Meeting Date: 4 August 2021

RELIABILITY INFORMATION AS OF MID-2021

SECURITY AND RELIABILITY COUNCIL

This is the 2021 annual reliability dashboard report, providing the SRC with reliability information.

Note: This paper has been prepared for the purpose of providing the SRC with reliability information. Content should not be interpreted as representing the views or policy of the Electricity Authority.

Contents

1. The purpose of this paper

This report provides the SRC with reliability information

1.1 The Security and Reliability Council (SRC) requested its secretariat prepare an annual report at the second meeting of each calendar year comprising various reliability measures and associated commentary.

1.2 The intent with these reports is to provide a dashboard of the available security and reliability data to the SRC. Section 4 contains examples of publicly available data.

1.3 In general, any large and sudden changes to the metrics in this paper would signal that further investigation was required. However, these metrics are not able to signal possible future problems. Identifying future reliability issues is the role of asset owners, and for distribution, potential future reliability issues are at the centre of several Commerce Commission customised price paths.

1.4 The aim of this paper is to identify areas of interest, and whether there may be a problem, from which more in-depth analysis would be needed to find root causes of any problem identified.

1.5 To ensure this regular paper remains effective, the secretariat may adapt it, for example, based on SRC feedback or where improved measures of power system management become available.

Reliability measures are important to consumers

1.6 Reliability is not an easy thing to monitor. Part of the future security and resilience (G2) review proposed by the Electricity Price Review (EPR) will think about how we can monitor reliability long term to put everyone in a better position to understand state of system reliability to support the Government, the SRC, and consumers' needs.

1.7 This monitoring may include development of a dashboard of indicators to potential risks to future security and resilience – how we would know if/when those risks are manifesting.

2. Limitations to the monitoring regime

2.1 There are limitations both on the quality of the data and the ability to forecast future reliability.

No low voltage monitoring

2.2 The Commerce Commission's information disclosure requirements for reliability do not go down to the low voltage level. While an Electricity Networks Association working group has done some work in this area, there is currently no immediate proposal to change the requirements.

2.3 With increased adoption of Advanced Distribution Management Systems (ADMS) some distributors are increasing their level of monitoring down to their low voltage networks to help them with visibility of changing patterns of consumer behaviour.

Data quality

2.4 Data quality problems occur in every industry and can manifest in many ways, such as:

a) Data availability – data may be lost (eg paper records destroyed) or was never collected in the first place.

b) Data consistency (eg changing what data is collected or in what format).

c) Data improvements over time - access to new data, data granularity changes, and modelling changes all have an effect.

d) Unexplained or unexpected causes behind data.

2.5 These quality issues can affect the ability to view trends, provide accurate forecasts, or know any measure with absolute certainty.

Forecasting reliability

2.6 One-off events such as the Penrose substation fire, or AUFLS trips, are idiosyncratic and while they may indicate systemic issues, it is not possible to forecast such events. However, these events are often worth reviewing thoroughly to understand and learn as much as possible. It is important that lessons from these events are disseminated.

2.7 Other approaches such as looking at the age of asset classes and developing a statistical understanding of reliability may give some indication of future reliability. This ought to be an important part of managing a network.

3. Reliability measures

Measures of system events

3.1 This section provides information on:

a) the count of voltage excursion notices.

b) various measures of management of power system frequency.

c) the count of times when reserves are less than required for security.

d) The count of grid warning notices for insufficient generation

e) primary and secondary transmission outage counts.

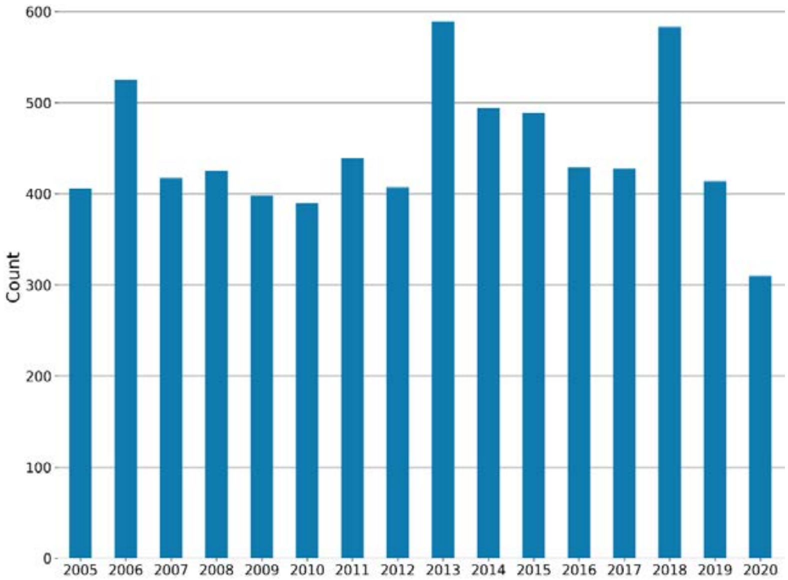
f) primary and maximum transmission outage duration in minutes.

g) (in appendix 1) the Commerce Commission’s new report *trends in local lines company performance*, with background information and additional links.

Count of voltage excursion notices

3.2 Transpower sends excursion notices[1] when voltage measures exceed stated limits. Figure 1 shows the annual counts of voltage notices, which are used to estimate the number of actual excursions. Excursion notice counts reflect the state of transmission and generation equipment. For example, an increase may indicate that assets are under pressure or getting to the end of their useful life. An upward trend would warrant further enquiries.

Figure 1: Voltage excursion notices



3.3 The drop in 2020 (to just over 300) is partly due to fewer notices issued during April when the country was at alert level 4. During this period several industrial users who are direct connects were turned off, so there was less equipment connected to the grid which could cause voltage excursions.

Management of power system frequency

3.4 In New Zealand, power system frequency between 49.8 Hz and 50.2 Hz is considered the ‘normal band’. However, the power system has been designed to cope with frequencies outside of the normal band (within limits).

3.5 The data in Figures 2-6 is sourced from the system operator.[2]

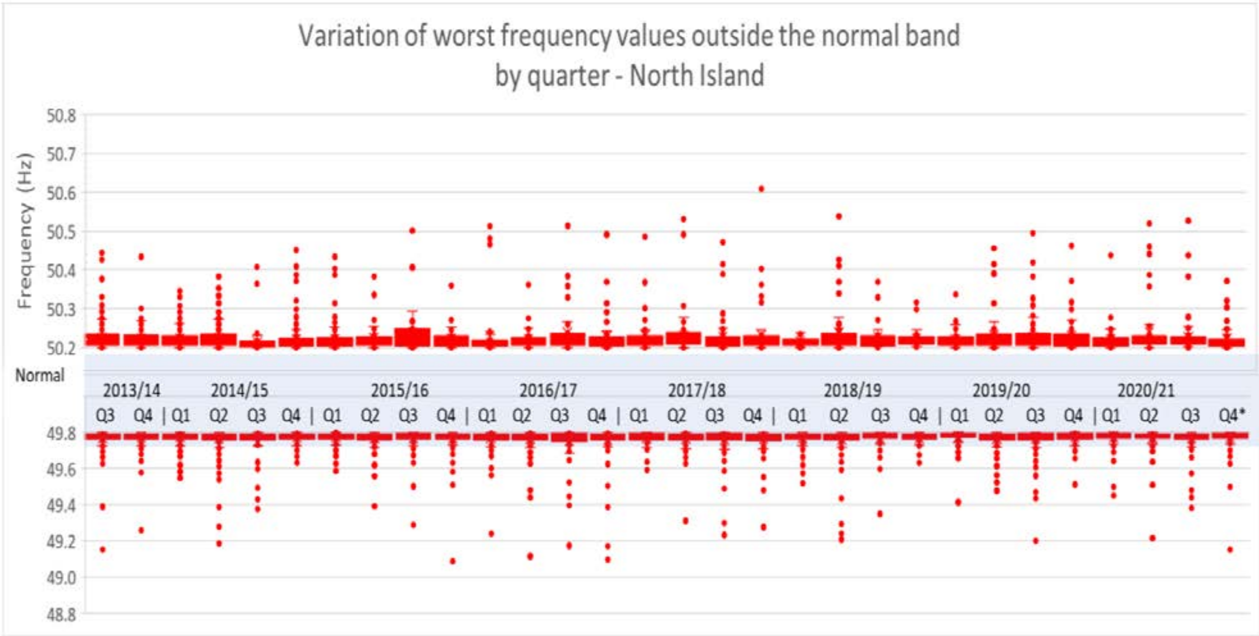
3.6 Figure 2 shows the number of frequency excursions by year.

[1] Source: https://www.transpower.co.nz/system-operator/operational-information/excursion-notices

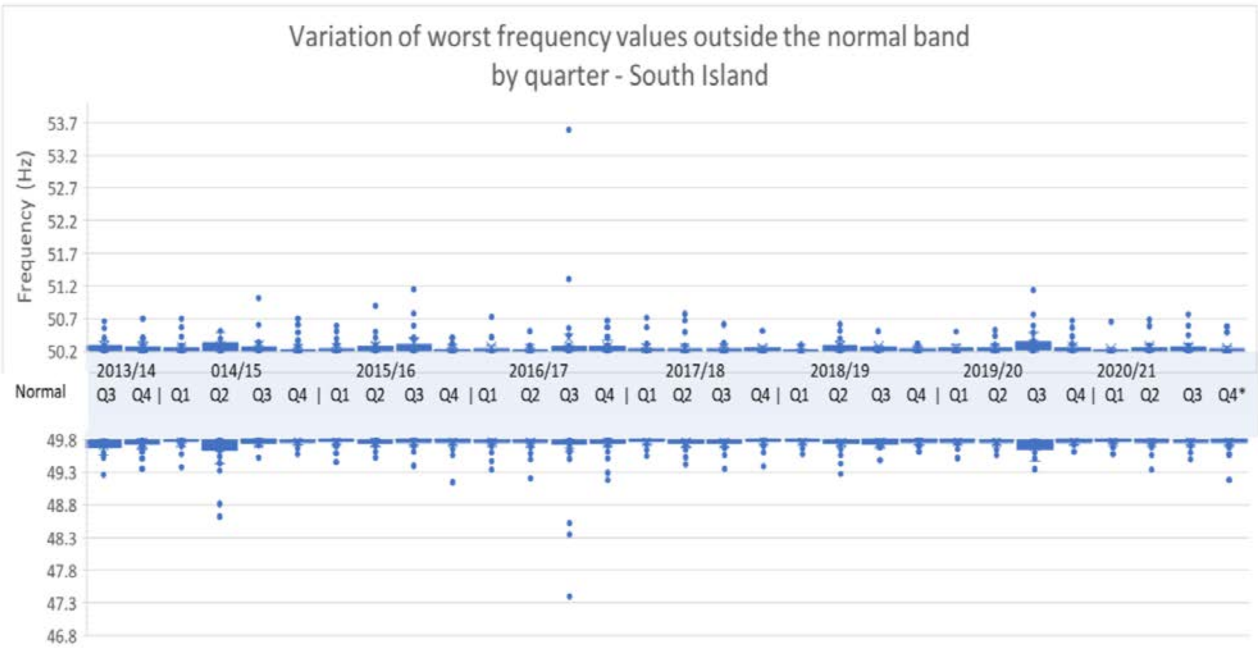
[2] Available from https://www.ea.govt.nz/operations/market-operation-service-providers/system-operator/monthly-reports/

Figure 2: Distribution of frequency outside the normal band (by island)

North Island



South Island



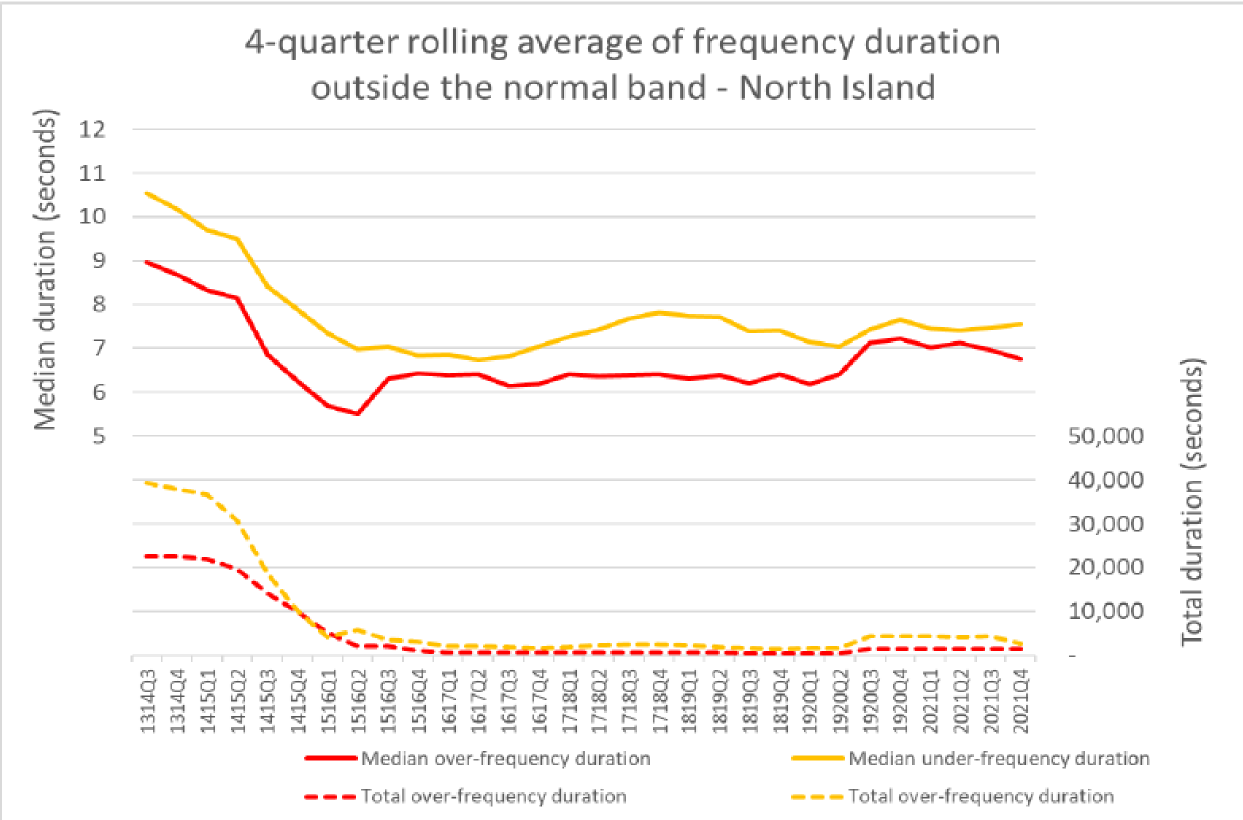
Note: These box and whisker charts show the distribution of data. The "box" represents the distribution of the middle 50% of the data, the "whiskers" indicate variability, and outliers are shown as single data points.

3.7 The above results show no trends of any alarm. For example, in the South Island, Q3 of the 2019/20 year (January to April 2020) shows a broader distribution of frequency maximums and minimums. That relates to Transpower's testing of its HVDC assets throughout that quarter.

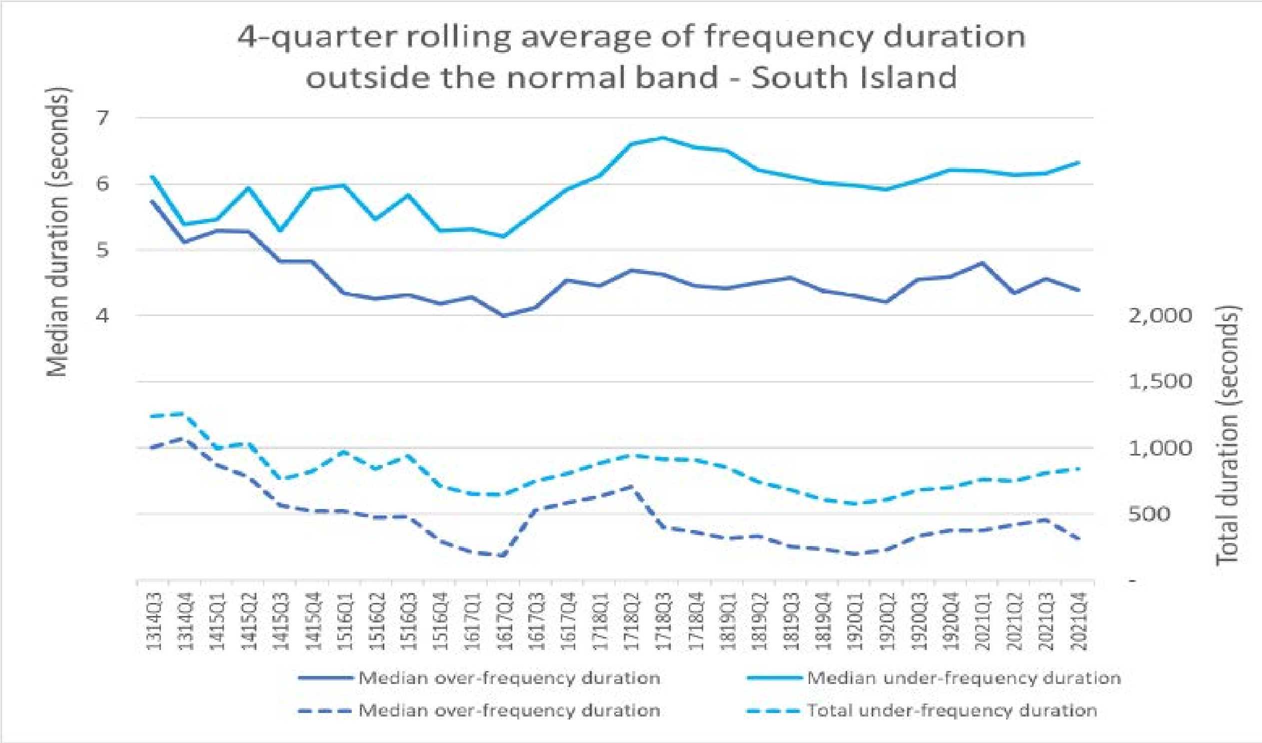
3.8 Figure 3 illustrates the duration of times that frequency exceeded the normal band. Each chart includes measures of median and aggregate duration. Median duration is essentially unaffected by outliers, so provides a better measure of typical performance. Aggregate duration provides a better measure of overall performance.

Figure 3: Duration of frequency outside the normal band (by island)

North Island



South Island



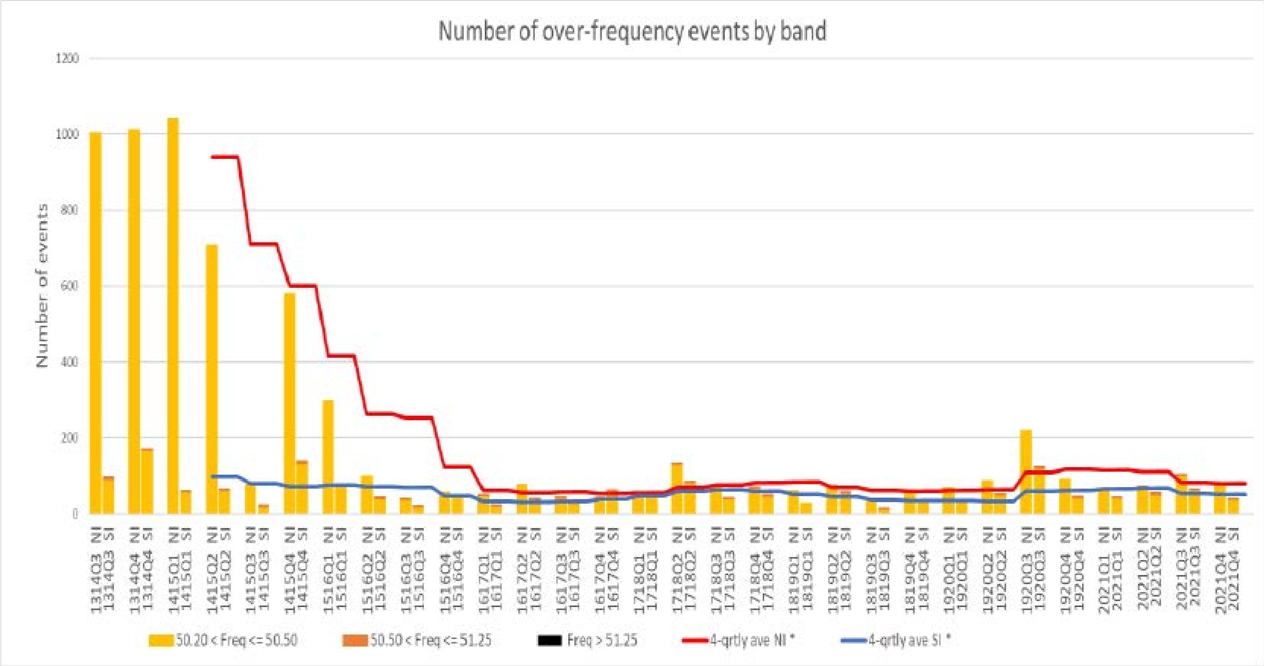
3.9 These charts illustrate the superior performance of frequency in the South Island across all measures of duration. This is largely a consequence of the South Island generation fleet (which is almost exclusively hydro) having better reliability and frequency response than the North Island fleet.

3.10 Transpower's HVDC testing in Q3 of 2019/20 is also evident in these charts. As previously noted, this was not the start of an upward trend in duration of frequency outside the normal band, as shown by the downward slope from Q3 2020-21.

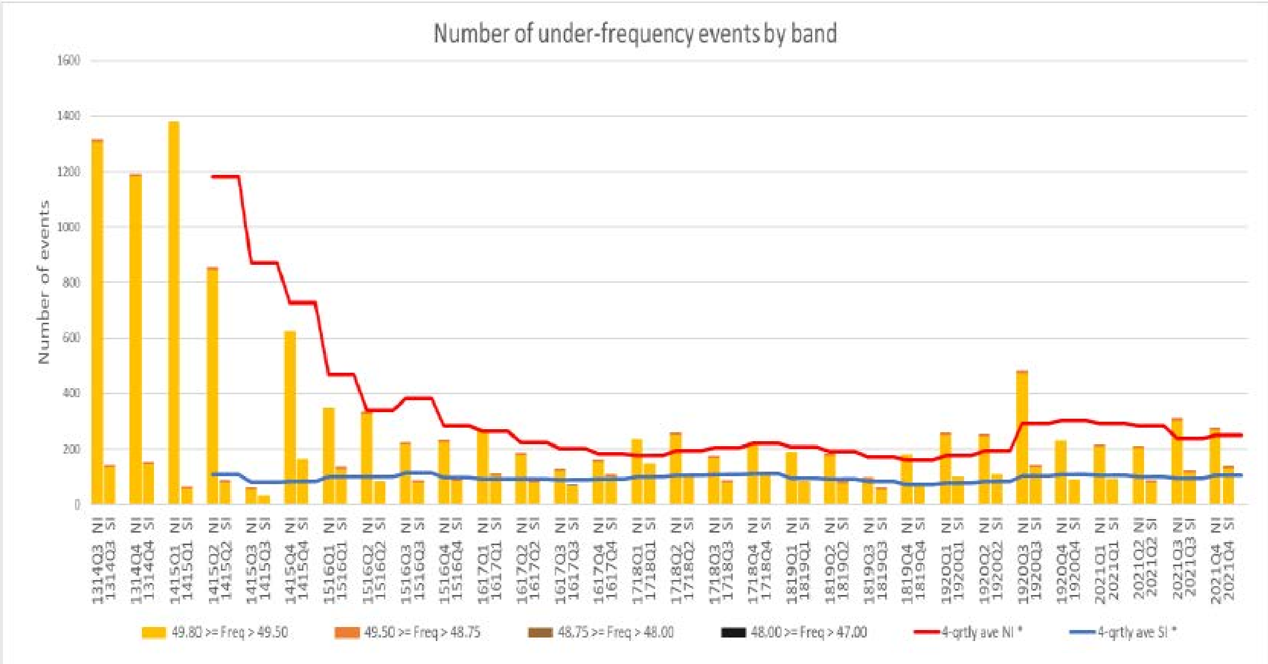
3.11 Figure 4 illustrates the number of instances in which frequency exceeded the normal band. The quarterly averages (the line chart) are solely an indicator of the number of instances and say nothing about the magnitude of the frequency outside of the normal band. However, the count of instances (the bar chart) is banded (and coloured) to give an indication of severity.

Figure 4: Count of instances of frequency outside the normal band (by island)

Over-frequency events



Under-frequency events



3.12 As with figures 2 and 3, Transpower's testing of the HVDC shows up in the third and fourth quarter of 2019 and the first and second quarter of 2020. Aside from that, there are no concerning results in figure 4.

3.13 All under-frequency events on the graph are in the yellow category, which is the smallest degree of variation (between 49.80Hz and 49.50Hz). This is a good sign.

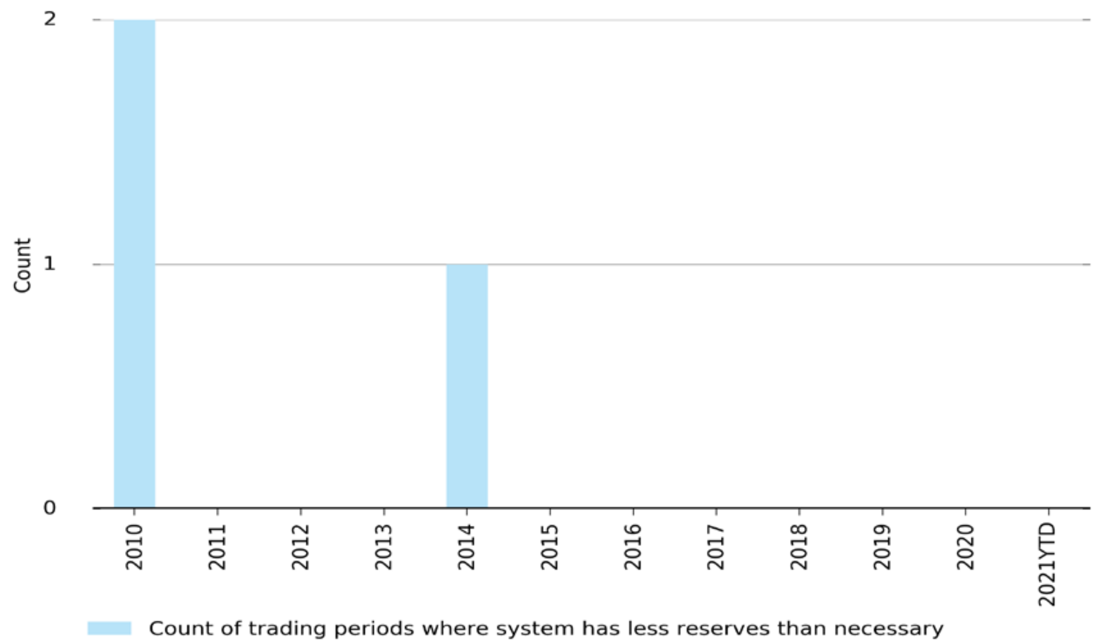
3.14 Compared to the North Island, the South Island has fewer instances of both under- and over-frequency outside the normal band. The difference between the islands is much larger with instances of under-frequency. This is also a consequence of the relative number, reliability and responsiveness of the generation fleets in each island.

Count of times when reserves are less than required for security

3.15 Figure 5 shows the annual number of occasions on which insufficient reserve was dispatched. Reserves are required to cover the largest risk in the system, usually a large generator or the HVDC. The system operator may not have enough reserve to cover the largest risk, after an event or due to inaccuracies in forecasting of supply and demand.

3.16 A trend of an increasing number of occasions of insufficient reserve being dispatched would warrant further investigation. The more such occasions, the higher the risk of an asset failure triggering the AUFLS system (thereby disconnecting load) rather than triggering reserves (which has no involuntary load loss).

Figure 5: Number of occasions on which insufficient reserve was dispatched



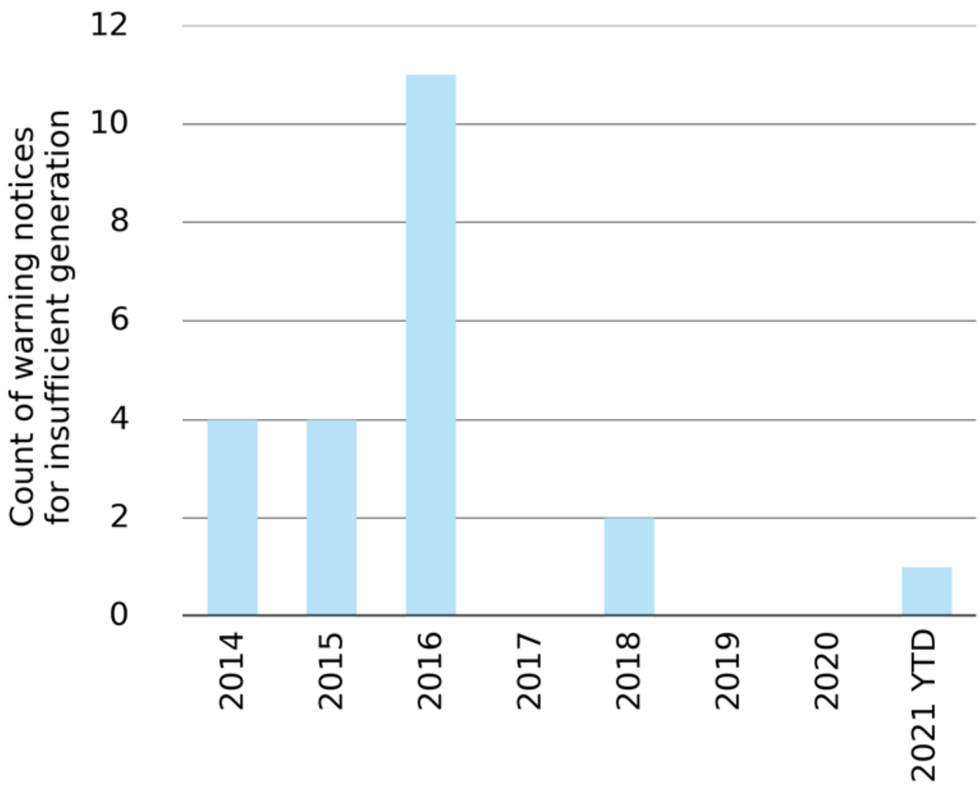
3.17 No such events have occurred since 2014.

Count of grid warning notices

3.1 Grid warning notices are issued by the system operator when there are insufficient offers to meet forecast demand. The number of grid warning notices for insufficient generation[3] issued each year is shown in figure 6. Trends in the numbers of grid warning notices can drive more detailed enquiries into things like maintenance scheduling and the incentives on generators to build new plant.

3.2 There has been one warning notice for insufficient generation issued so far in 2021.

Figure 6: Number of grid warning notices for insufficient generation



Measures of transmission grid reliability

3.3 This section provides information on:

a) primary and secondary transmission outage counts.

b) primary and maximum transmission outage duration in minutes.

[3] Source: https://www.transpower.co.nz/system-operator/operational-information/formal-notices

Primary and secondary transmission outage counts

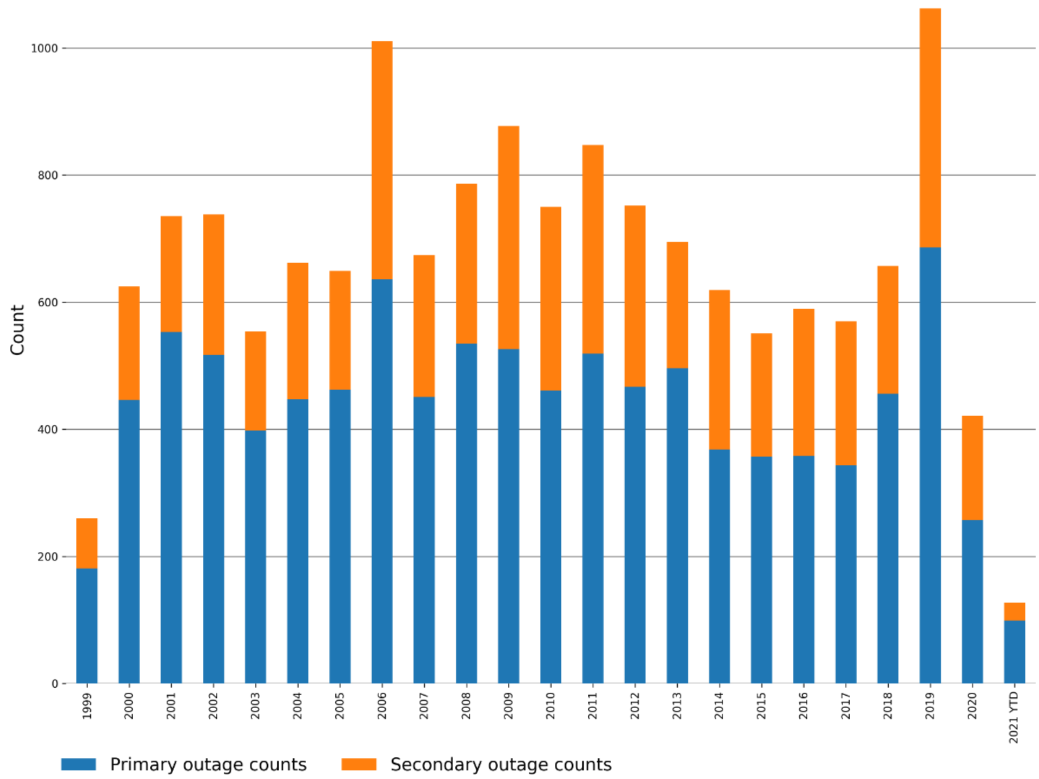
3.4 The information in this section specifically refers to forced outages, defined as those for which the equipment was tripped or manually taken out of service within 24 hours of the fault occurring or being discovered.

3.5 ‘Primary outage’ refers to the first piece of equipment to go out; a ‘secondary outage’ is a different piece of equipment that went out as a result of the primary outage.

3.6 A number of outages within a relatively short space of time, sharing a cause, are generally recorded as a single incident. If a second fault occurs or is discovered when attempting to return equipment to service, it is counted as a second outage.

3.7 Annual counts of primary and secondary outages are shown in figure 7.

Figure 7: Transmission forced outages



3.8 There has been a generally decreasing trend in the number of primary forced outages since 2011. The number of forced outages in 2020 was the second lowest in over two decades.

3.9 Figures 7a and 7b show the trends for primary and secondary forced outages, respectively.

Figure 7a: Primary forced outage trend

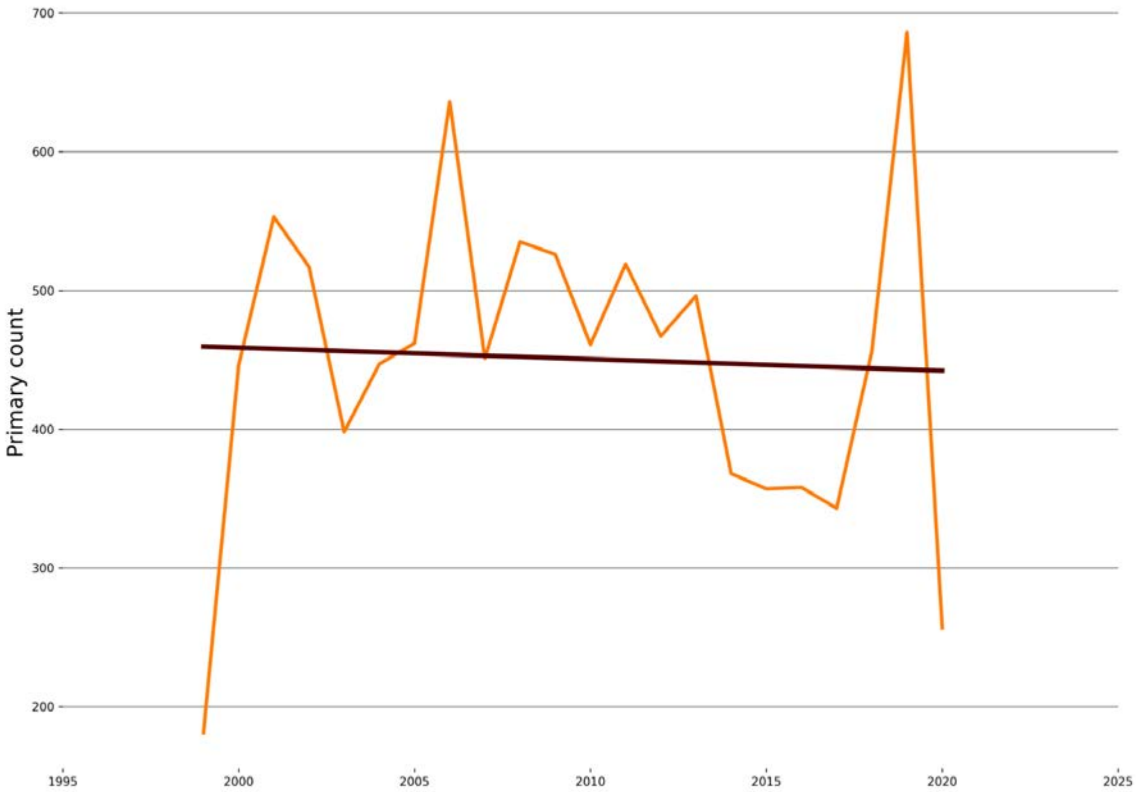
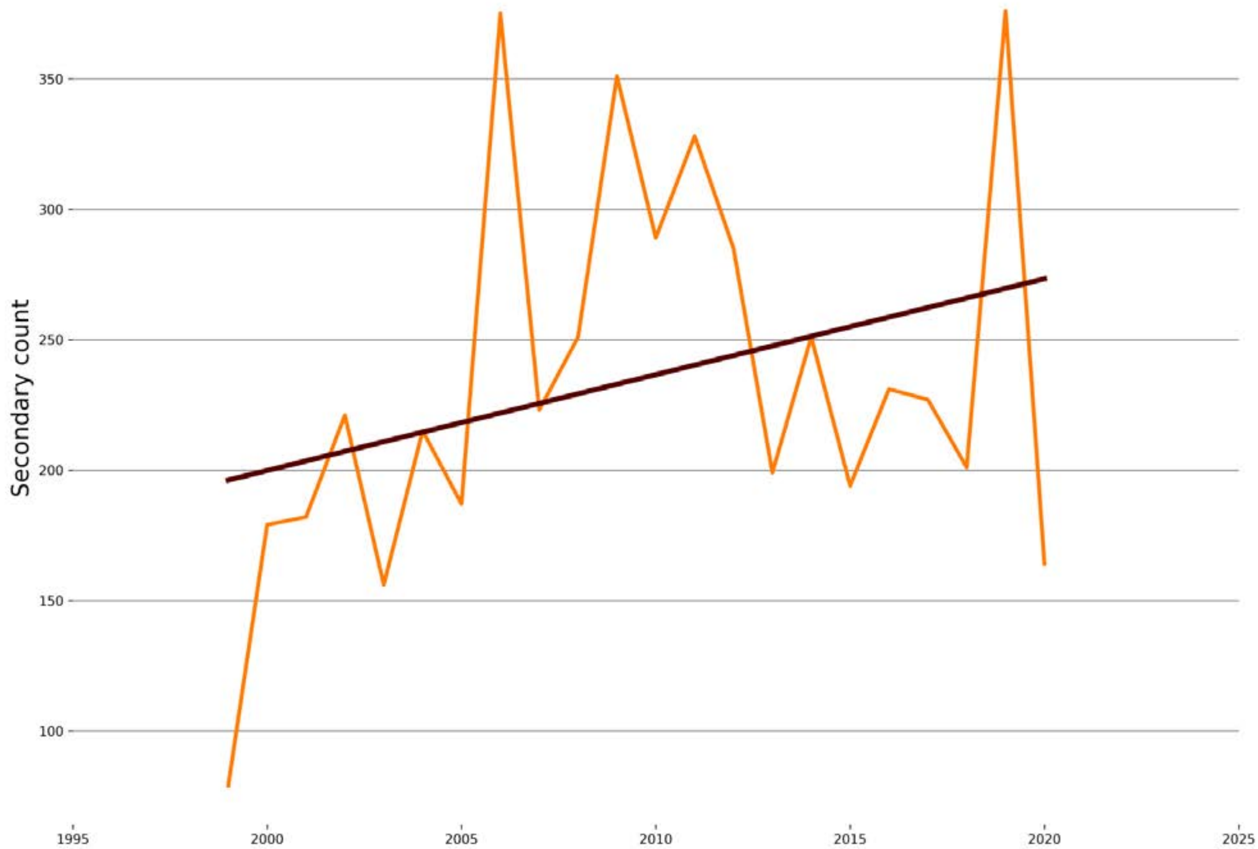


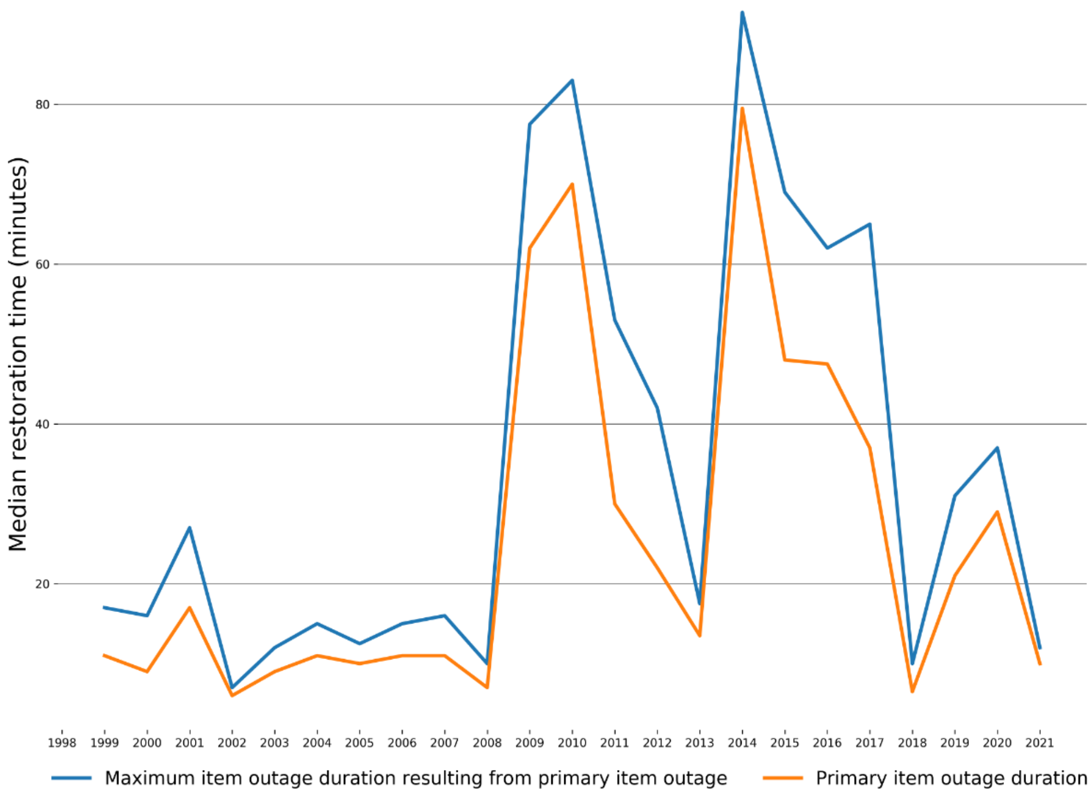
Figure 7b: Secondary forced outage trend



Primary and maximum transmission outage duration in minutes

3.10 Trends in the typical duration of transmission forced outages are shown in figure 8. The blue line indicates the annual median of the duration of primary outages (in minutes). The orange line indicates the annual median of the *maximum* duration of all outages (primary or secondary) relating to a single primary outage – arguably a better measure of how long it takes to return the grid to normal operation.

Figure 8: Median transmission outage duration



Measures of distribution network reliability

3.11 This section provides information on EDB network reliability.

3.12 The Commerce Commission now publishes a report entitled *Trends in local lines company performance.*[4] This reports across a range of reliability and other metrics. As noted in its inaugural report:

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

[4] The report (and associated dashboard) is available at https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/trends-in-local-lines-company-performance

3.13 SRC members are encouraged to read chapter 1 of the report, (attached as Appendix 1) as that sets out the Commerce Commission's approach, with links to more technical information and other reports.

4. Other available data

4.1 Reliability data is improving steadily with the installation of more sophisticated equipment and processes, and digital access to records.

4.2 The following information sources are publicly available:

a) Authority reports into automatic under-frequency load shedding (AUFLS) events: https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/

Data from the system operator

4.3 The Security of Supply Annual Assessment and any ad hoc system operator studies: https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment

4.4 Electricity risk curves[5], which are available from the system operator and on EMI[6].

4.5 The system operator is working to improve their monitoring. They have:

a) developed a Dispatch Accuracy dashboard for energy dispatch.[7] It is a means of monitoring overall performance of the system operator's load forecasting, scheduling and real time adjustments to dispatch. It relates to reliability in the sense that more accurate dispatch means that the frequency keeper has to respond less to generation fluctuations.

b) committed to improved monitoring of the accurate dispatch of reserves. The system operator is required to dispatch the minimum amount of instantaneous reserves needed to maintain frequency within prescribed limits for certain events.

4.6 Figure 9 is a screen shot of the measures available in the dashboard.

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5 Previously known as 'hydro risk curves'

6 https://www.emi.ea.govt.nz/Environment/Reports

7 Available from https://www.ea.govt.nz/operations/market-operation-service-providers/system-operator/monthly-reports/2021/

Figure 9: System operator dispatch accuracy dashboard measures

Operator discretion applied	Total number of instances (5-minute dispatches) where operator interventions depart from the dispatch schedule to ensure the dispatch objective is met.
	Instances where the system operator has applied discretion under 13.70 of the Code to meet dispatch objective
Frequency keeper (MW)	Average absolute deviation (MW) from frequency keeper dispatch point. A movement of frequency keeping units away from their setpoint suggests greater variability in the system, but can also indicate the need for additional dispatches
Time error (s)	Average absolute daily time error (s) indicates imbalance between generation and load, a reflection of imperfect dispatch
Frequency excursions	Number of frequency excursions (>0.5Hz from 50Hz)
FK within 1% of band limit	% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.
FK outside of band limit	% of time frequency keepers spend outside their regulation limits
HVDC modulation beyond 30MW band	% of minutes where the maximum HVDC modulation exceeds 30MW away from its dispatch setpoint. This indicates greater variability in the system, but can also indicate the need for
Constrained on energy- Total	Total Monthly Generation Total constrained on - All sources
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.
Dispatch load accuracy error (%)	Average absolute difference between forecast generation (load plus losses, including PSD) and actual generation relative to the average actual generation
Wind offer accuracy (%)	Average absolute difference between persistence wind offer (based on 5mins prior) and the actual wind output relative to the average wind output

Data from the Commerce Commission

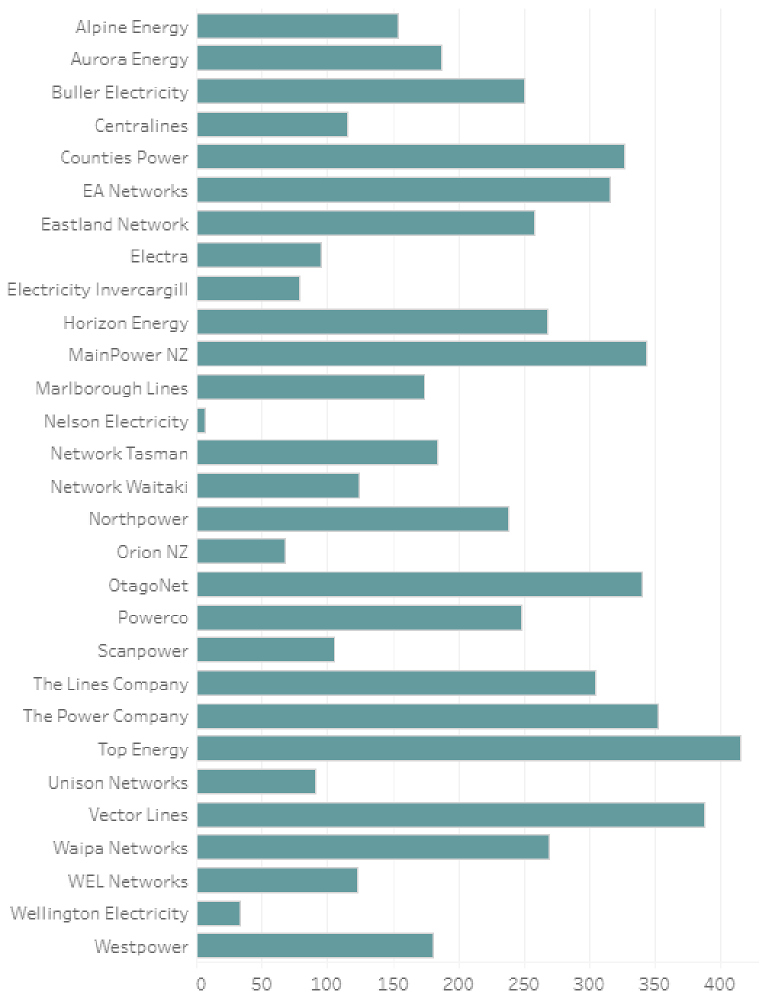
4.7 The Commerce Commission has a large set of metrics publicly available[8] on EDBs, including System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) maps and asset conditions. We have reproduced a selection of graphs below.

SAIDI and SAIFI measures

4.8 SAIDI and SAIFI are two of the measures the Commerce Commission monitors for ensuring customers are receiving a reliable standard of service.

4.9 SAIDI is calculated by adding all customer interruption durations and dividing it by the total number of customers served, to give, on average, the number of minutes a customer was without power over the course of the year. Figure 10 gives the 2020 SAIDI by EDB.

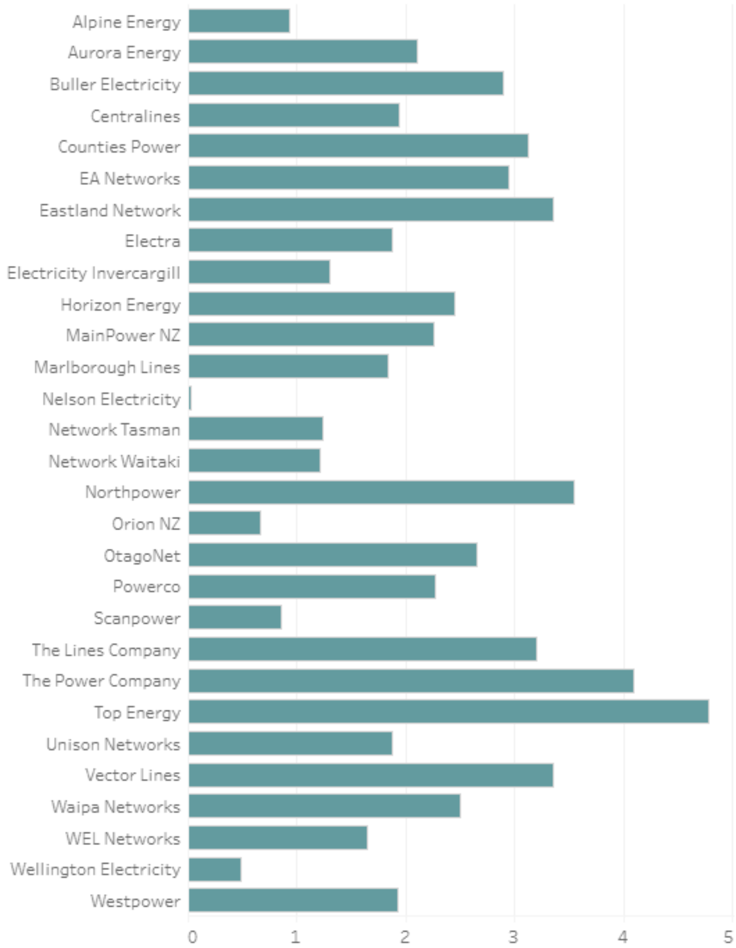
Figure 10: 2020 SAIDI by EDB



8 https://public.tableau.com/profile/commerce.commission.regulation#!/vizhome/Performanceaccessibilitytool-NewZealandelectricitydistributors-Dataandmetrics/Homepage

4.10 SAIFI is calculated by taking the total number of customer interruptions divided by the total number of customers served, to tell us, on average, how many times the power went out for each customer over the course of the year. Figure 11 gives the 2020 SAIFI by EDB.

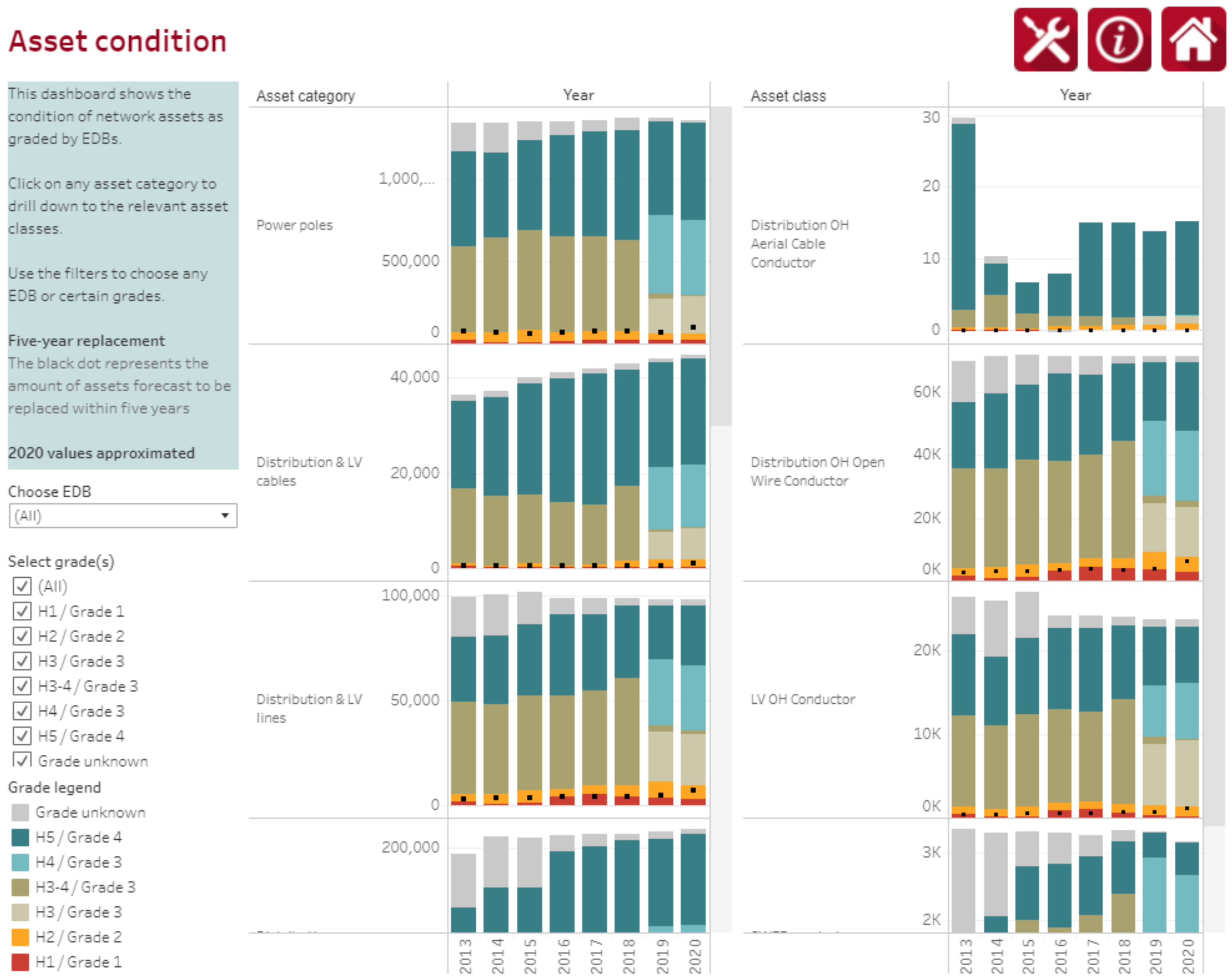
Figure 11: 2020 SAIFI by EDB



4.11 The Commerce Commission sets a target 'threshold' for SAIDI that 17 EDBs are incentivised to achieve ('price-quality regulation'). There are a further 12 EDBs not subject to price-quality regulation. All 29 EDBs are subject to information disclosure obligations to ensure SAIDI, SAIFI and other reliability measures can be scrutinised by stakeholders.

Other reliability measures

4.12 The Commerce Commission holds additional detailed data which can give an overview of the system. A sample of this data which highlights asset condition of power poles, is included below to give the SRC an idea of what is available for further analysis.



5. Questions for the SRC to consider

5.1 The SRC is asked to consider and provide advice on the following questions:

Q1. Does the SRC want to receive different data in the 2022 version of this report?

Q2. Having considered this report, what advice, if any, does the SRC wish to provide to the Authority?

Appendix A: Commerce Commission paper: Trends in local lines company performance

COMMERCE COMMISSION NEW ZEALAND
Te Komihana Tauhokohoko

Trends in local lines company performance

Local lines companies' performance trends

The Commerce Commission has released performance trends for New Zealand's local lines companies

We have released a breakdown of revenue and reliability trends that help to explain why local lines company charges in New Zealand have been increasing over the 12 years since 2008. The analysis also gives insight into the frequency and duration of power cuts (outages) local lines companies have experienced over the same period.

Profitability has been reasonable

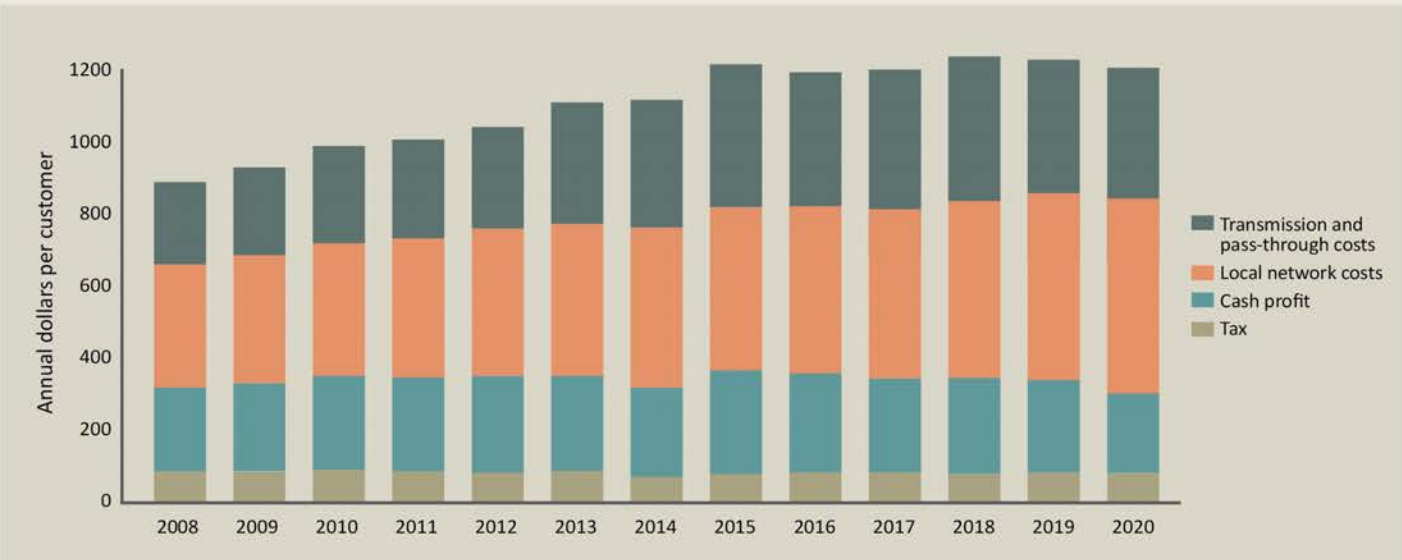
While there are differences between each local lines company, the level of profitability or return on investment across the industry has generally been around 5% to 6% between 2013 and 2020. That is below the estimates of reasonable returns that we have used for setting price limits for some of the local lines companies (7.8% for 2010-2015 and 6.4% for 2016-2020). The lowest annual return on investment averaged over the period was 2.1% by Marlborough Lines and the highest was 7.2% by Electra.

Interactive dashboard and report now available

You can learn more about the industry and your local lines company on our new dashboard and in our report.

Lines charges have increased to support investment in infrastructure

The chart below shows that annual lines charges have increased by $350 for each customer on average between 2008-2020. This equates to an inflation adjusted increase of 1.2% per customer each year (average inflation over the period was 1.8% per annum). A key driver of the increase in lines charges has been to pay for increased investment in the national transmission network. Network costs have also increased because local lines companies have been investing in their networks to support growth and replace aging assets.

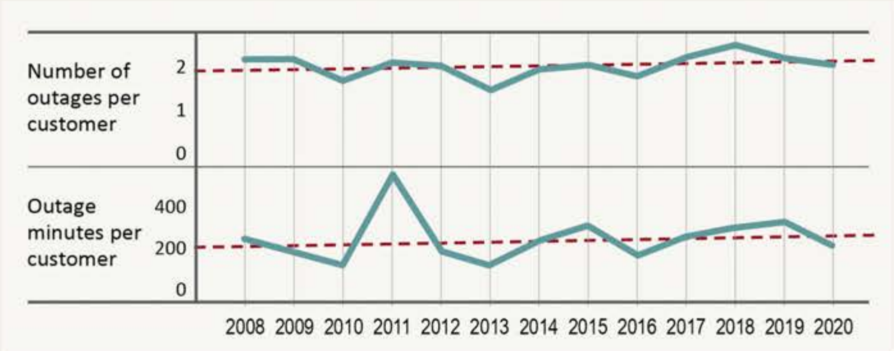


Little change to reliability

The average number of outages that each customer experiences has remained similar over time—while there are more outages in total, they tend to be smaller in scope, each one affecting fewer customers. We also found that outages tend to last slightly longer than they used to. Our results include some major events, such as earthquakes and storms.

Outage performance varies by lines company and by customer. Customers on many networks will have experienced some improvement in reliability. While the trends for unplanned outages are different across each of the lines companies, the number and duration of planned outages has increased for almost all lines companies. This reflects the high levels of investment to improve and replace assets. It may also have been affected by changes to health and safety practices, which aim to improve safety for lines workers but can mean longer outages.

Vector and Aurora lines companies have had significantly worsening reliability, for which they have been penalised in Court. We continue to investigate other lines companies where we are concerned about poor reliability outcomes.



Average **number of outages** per customer per year

1.9

This represents an annual increase of **1%** per year

Average total **length of outages** per customer per year

235 minutes

This represents an annual increase of **2%** per year

Biggest improvement in reliability

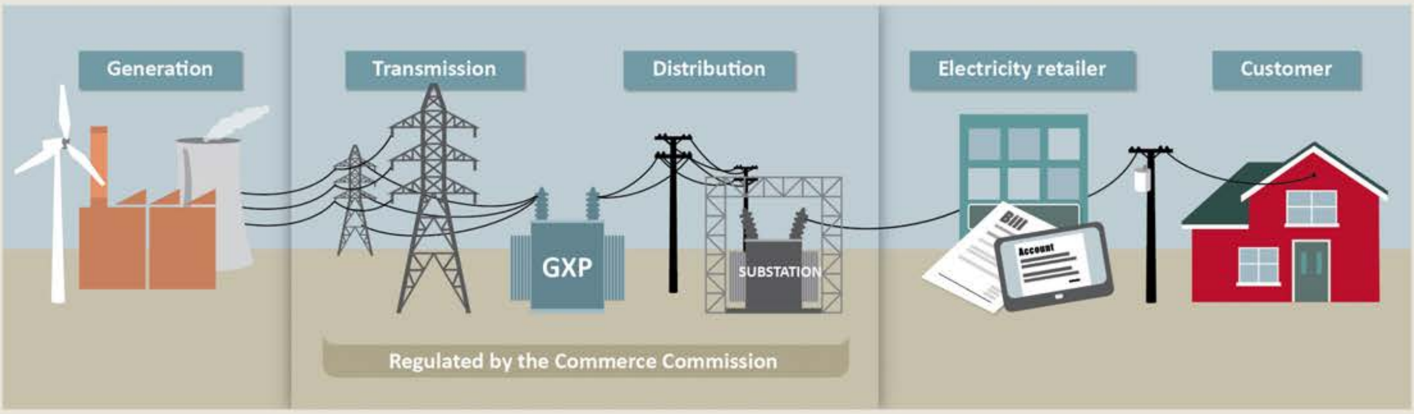
Nelson Electricity

Biggest deterioration in reliability

Aurora

What makes up my electricity bill and what portion does the Commerce Commission regulate?

Under Part 4 of the Commerce Act, we have a role regulating markets where there is little or no competition (and little prospect of future competition). Local lines companies and our national transmission network operator, Transpower, fall into that category. Combined transmission and distribution lines charges make up approximately 38% of the average consumer electricity bill. There are 29 local lines companies and one transmission company.



Why did the Commerce Commission conduct this analysis?

Part of our role is to require the lines companies to disclose information about their performance and for us to share our analysis of that performance. This set of analysis looks at the changes in prices over time and explores the causes of those price changes. It also assesses the changes in reliability over time.

COMMERCE COMMISSION NEW ZEALAND
Te Komihana Tauhokohoko

Contents

The accompanying paper titled 'Approach to trend analysis of local lines companies', describes the technical detail of the analytical approaches we have used and the legislative context of our analysis.

Chapter 1 – Introduction

Purpose of this report

The purpose of this report is to help people 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 give insight into the issues affecting local lines companies, which can then help inform a clearer impression of their performance.

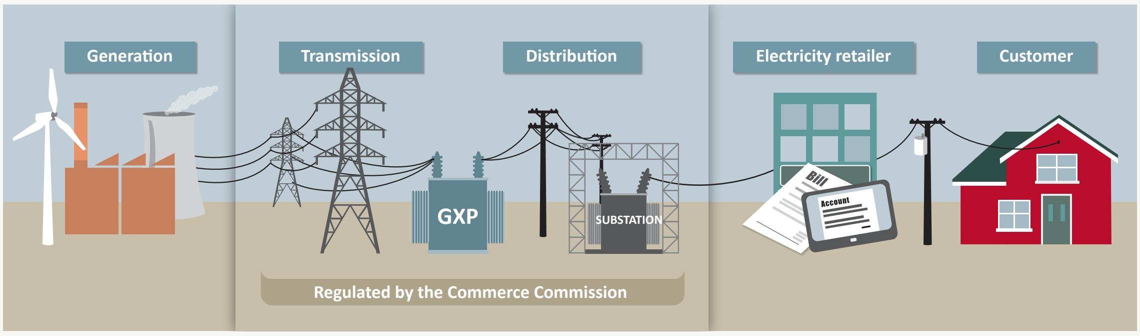
This report presents and discusses analysis we have undertaken to identify past trends in local lines companies' revenue and reliability, and examines the underlying drivers of those trends. It gives a high-level picture of these trends at an industry and individual company level and helps identify areas 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 under Part 4 of the Commerce Act 1986. Our responsibilities under the Act are described in the associated paper 'Approach to trend analysis of local lines companies'.

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



We use the term 'customers' to mean the entities 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 percent 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' revenue. By analysing changes in local lines companies' 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 2020 (years ending 31 March).[1,2] It considers the local lines companies' revenue and costs, and the quality of services they provided over that period.

1. All years discussed in this report are years ending 31 March unless otherwise specified.
2. Given the timing of this report and our receipt of the 2020 data, the 2020 data has not yet been subject to our full checks for compliance with our regulatory rules.

We expect that this analysis will be of interest to all stakeholders. Electricity sector stakeholders need to have confidence that the prices electricity customers pay for local lines companies reflect an industry that is working efficiently, and for their long-term benefit. 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 alongside this report

We intend this to be a regular report that we will update as new data becomes available, and to build in fresh analysis and insights.

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

- A paper titled 'Approach to trend analysis of local lines companies', which describes the technical detail of the analytical approaches we have used and the legislative context in which we undertake this approach.
- A fact sheet highlighting some of the key findings of our analysis.
- An online interactive dashboard that will walk users through the key findings and allow them to look further into the results if they choose.
- 'Live' graphs in our Performance Accessibility Tool, where our analysis will be kept up to date as new data becomes available, and where users can dig deep into the detail of the data.

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 ID data that we have undertaken over time, which can be found on our website.[3]

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

- *A database of the ID data* – this groups the raw data disclosed by each local lines company into a single, manipulatable repository in Microsoft Excel.
- *The Performance Accessibility Tool* – this is an online portal that visualises the ID data, including profitability and revenue, capital and operating expenditure, asset condition and age, and reliability data. The tool is interactive, allowing the data to be interrogated and summarised at various levels.[4]
- *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.[5]

3. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data
4. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors
5. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-summaries-for-electricity-distributors

We also produce in-depth pieces of analysis across the range of performance areas. We have published:

- A review of local lines companies' forecast expenditure and the drivers of that expenditure.[6] This review took place in 2013 and helped to inform our approach to setting price-quality paths.
- An initial snapshot report providing a high-level picture of the revenue, reliability, and expenditure of local lines companies between 2008 and 2011.[7]
- An assessment of local lines company profitability.[8] This 2016 publication helped to answer the frequently asked and important question of whether the average level of local lines company profit is appropriate. We considered this work a high priority, as customer confidence is dependent on the extent to which excessive profit is limited, and we wanted to also be sure that profits are sufficient to support necessary investment.
- A report of our observations from our review of local lines companies' 2016 and 2017 asset management plans.[9] This report built on engagement with local lines companies and other stakeholders about whether local lines companies are managing their assets for the long-term benefit of consumers.
- An external report on the level of risk preparedness shown in the local lines companies' asset management plans.[10] This was published in 2019 and was intended to further the conversation on risk and resilience with regards to information that is readily available for interested stakeholders.

We also have work underway that continues our scrutiny of local lines companies' asset management reporting. This review, which began in 2019, aims 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 their planned response to addressing such issues. The resulting report will highlight examples of best practice reporting, as well as instances where we considered the discussion insufficient.

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6. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/summary-and-analysis-of-information-disclosed-by-electricity-distributors
7. See https://comcom.govt.nz/__data/assets/pdf_file/0011/63110/Overview-of-electricity-distributors-performance-from-2008-2011-chapters-1-4-of-full-analysis-updated-5-February-2013.pdf
8. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/profitability-of-electricity-distributors
9. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/review-of-asset-management-practices/review-of-asset-management-plans
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Chapter 2 – Our key findings

Purpose of this chapter

This chapter discusses the key findings across our range of trend 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.

- We have found, on average, that the amount of profit that lines companies receive from each customer has remained roughly the same since 2008. Overall, the amount of profit being made by local lines companies over the period was reasonable.
- Despite the profit-per-customer remaining static, rising costs mean customers are paying $350 more per year now than in 2008, or $165 if adjusted for inflation, rounded to the nearest $5.[11] This is equivalent to an increase of 38% in nominal terms, and 15% after adjusting for inflation. The increase was greatest from 2008 to 2015, and has since slowed for a variety of reasons including slower inflation and lower finance costs.
- Of this increase of $350, nearly half of it ($165) 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 $80 per year more from each customer so they can recover the costs of increased investment that they made to support growth and ensure healthy assets. Local lines companies are spending more on running their businesses and operating their electricity networks too, resulting in a $110 average increase per customer since 2008.
- The average number of unplanned power outages per customer across the industry has remained similar over this time. However, 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 may have been the changes that some lines companies made to their health and safety practices, such as undertaking less work while the power is still on.

We have also concluded that some trends, such as the increasing non-network expenditure by local lines companies, may warrant further analysis at some point in the future.

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 associated report 'Approach to trend analysis of local lines companies' regarding our use of trend analysis.

Further, unless otherwise stated, the charts and figures for monetary data are given in nominal terms – ie, they have not been adjusted to exclude the impact of inflation.

11. The components do not add up to the total because of rounding.

Customers on average pay local lines companies $350 per year more than they did over a decade ago

Local lines company revenue has increased faster than networks have grown

In aggregate, local lines companies' revenue grew by 53 percent in nominal terms between 2008 and 2020, and 38% on a per-customer basis due to the growth in the number of customers being served.[12] The revenue growth is shown in Figure 2.

The number of customers connected to a local lines company, and the energy and power supplied to those customers have all grown over the same period - by 10 percent, 10 percent and 8 percent in total, respectively.[13] However, revenue has increased faster than these drivers of network growth, meaning customers on average have experienced an increase in price. In 2020, customers paid, on average, approximately $350 more than in 2008 (in nominal terms).[14] This is shown in Figure 3.

We have principally 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.

The trends would be largely the same if we had instead used energy (kWh) or peak demand (kW) as measures of growth.[15]

Figure 2: Total revenue and trend for all local lines companies, 2008-2020

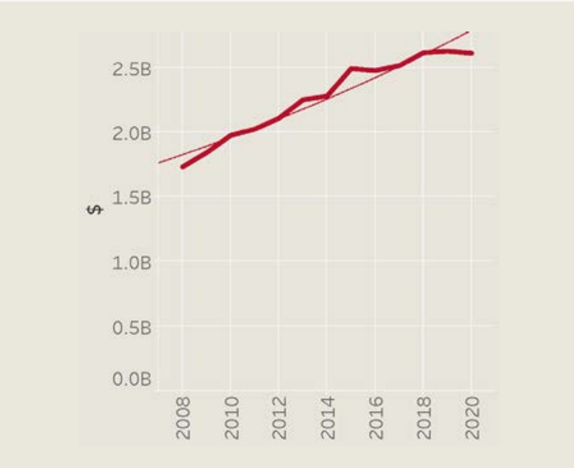
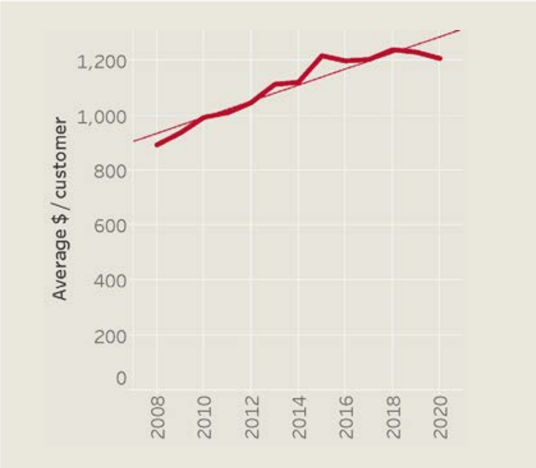


Figure 3: Average revenue per customer and trend, 2008-2020



12. Our analysis refers to the growth implied by the trend, rather than the absolute increase in dollars or dollars per customer between 2008 and 2020.
13. Energy and power are closely related but are not the same physical quantity. Energy is a measure of the ability to do work, which can be measured in watt-hours (or kWh, MWh, GWh etc); power is the rate of producing or consuming energy, and is measured in watts (or kW, MW, GW etc).
14. New customers may also have paid an upfront amount to help fund their connection to the network, as we discuss later.
15. 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.

Local lines company revenue has increased nearly twice as fast as inflation

Some of the nominal increase in revenue reflects general price pressures that impact across the whole economy. Local lines companies' annual revenue grew by 53 percent in total, or by $350 per customer, in nominal terms. After adjusting for inflation using the consumer price index, revenue increased by 27 percent in total, or $165 per customer over this period. For customers, this means that network prices have, on average, increased at close to twice the rate of inflation.[16]

Figure 3 highlighted that customers on average will have experienced nominal price increases that have slowed over time. This is both because of lower inflation, and slower growth in the revenue recovered by local lines companies.

Inflation has varied over time, but was higher in the first half of our data period than in the latter half. This is shown in Figure 4, which gives the annual rate of inflation, as described by Stats NZ's consumer price index.

Figure 5 shows the rate of change in local lines company revenue after removing the effects of inflation. This shows that the rate at which underlying local lines company revenue has changed has fluctuated significantly from year-to-year. However, it too increased at higher rates in the early and middle parts of the data period compared to the most recent years.

Figure 4: Annual rate of inflation

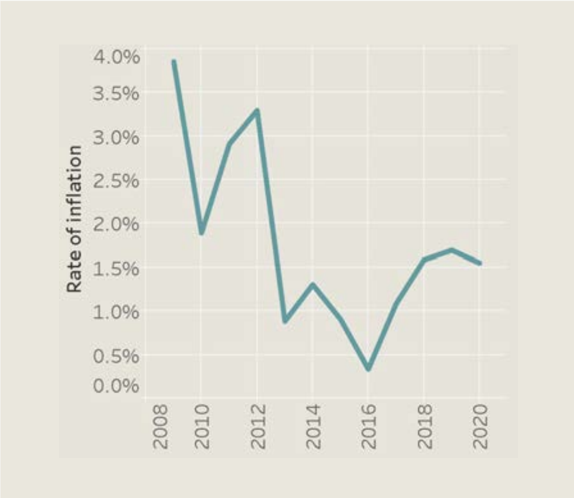
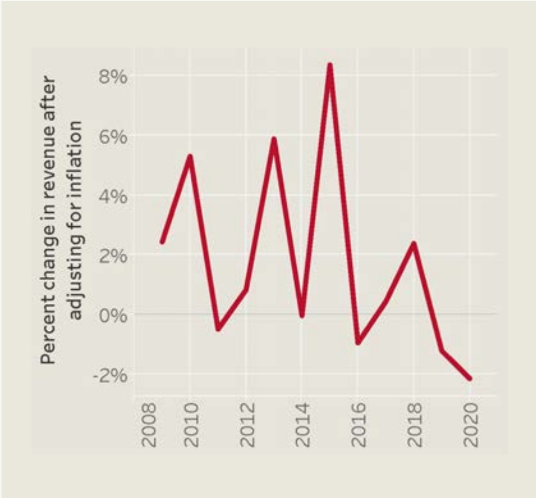


Figure 5: Change of local lines company revenue adjusted for inflation



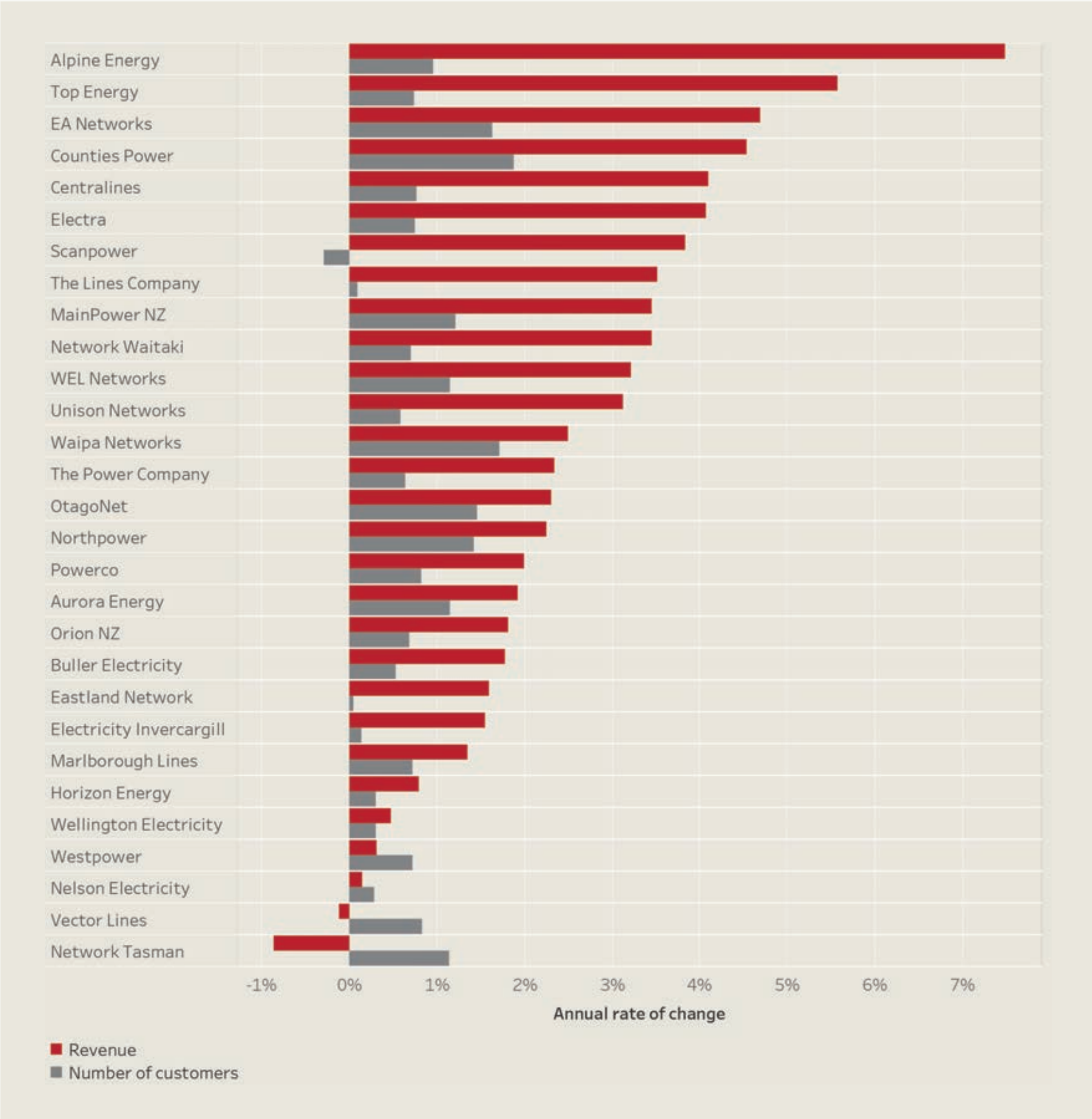
We first set price-quality paths for price-quality regulated local lines companies in the 2010 year, and reset them again in 2013 and 2015. Step-ups in revenue are evident in each of these years, as we had sought to allow each supplier's forecast revenue to align with their reasonable forecast costs. We typically allow for any significant realignment in the first year of the regulatory period, with only changes in line with inflation allowed in future years. While the values in Figure 5 include local lines companies that are exempt from price-quality regulation, the non-exempt local lines companies dominate the results because they include the largest companies. The non-exempt local lines companies earned 81 percent of the total revenue earned by all local lines companies between 2008 and 2020.

16. In accounting for inflation, we have used the historic consumer price index as provided by Statistics New Zealand.

Changes vary across local lines companies

After excluding the effect of inflation, nearly all individual local lines companies have had increases in revenue that are faster than their customer growth. However, each local lines company's rate of revenue growth has differed quite significantly. This is shown by Figure 6, which shows the annual rate of revenue growth in constant 2020 dollar terms (red bars), along with the rate of annual customer growth (grey bars).[17] It covers a shorter period (2010-2020) due to data limitations.[18]

Figure 6: Annual rates of change of revenue (adjusted to remove impact of inflation) and customers by local lines company, 2010-2020



17. The annual rate of revenue growth refers to the average annual change in the trend rather than the average of each annual change.
18. 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.

This figure shows that the annual average revenue growth (adjusted to remove the impact of inflation) has ranged from 7.5 percent for Alpine Energy (111 percent over the 10 years since 2010) through to an annual decrease of 0.9 percent for Network Tasman (down 8 percent over the ten years since 2010). It also demonstrates that there is little relationship between revenue growth and connection growth, though only four local lines companies (Westpower, Nelson Electricity, Vector Lines and Network Tasman) have had revenue grow slower than connections.

For price-quality regulated local lines companies, the rates of growth reflect the revenue limits we imposed.[19] For example, we allowed the increase for Alpine Energy to allow for a normal return and because of their need for revenue to fund a significant investment programme due to growth on their network. Similarly, the decrease by Vector Lines is reflective of significant restraints on revenue that we introduced in 2013 to limit excessive profit.

Local lines company revenue funds four primary components

Line charges provide local lines companies with revenue that allows them to recover four 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.[20]
- Local network costs – costs that directly relate to the services the local lines company provides;
- A component they retain as a cash profit;[21] and
- Tax, which is primarily driven by profit.[22]

19. More information on price-quality regulation – including which local lines companies are covered by it – is provided on our website.
20. 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.
21. 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.
22. Our analysis only identifies the 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 and Figure 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.

Figure 7: Breakdown of revenue, 2008-2020

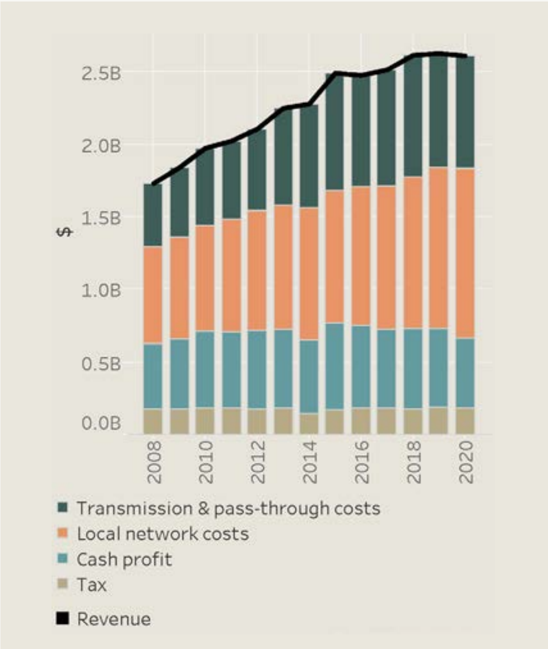
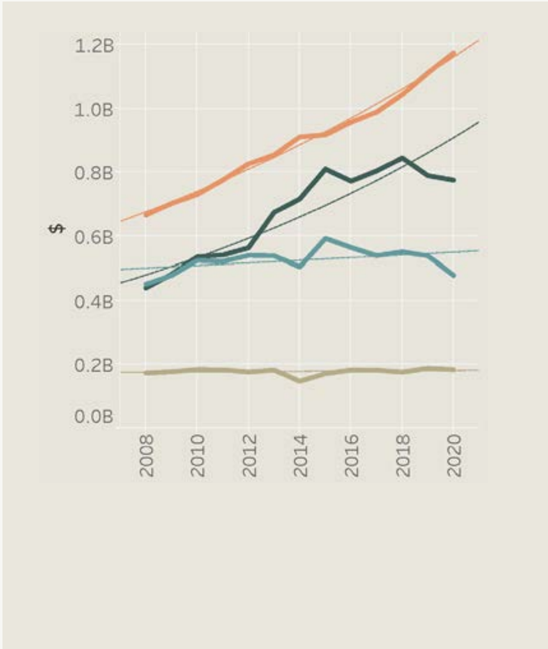


Figure 8: Change in components and trends, 2008-2020



These figures highlight that local lines companies' own network costs are the largest of these components – around 36 percent of all revenue between 2008 and 2020 went towards local network costs. Local network costs have increased consistently over the period at an annual rate of 4.5 percent in nominal terms. Over the thirteen years, annual costs have risen by around 72 percent or $480 million.

Transmission and other pass-through costs were a smaller proportion of total costs over the period – around 30 percent. However, they have been the fastest growing component, trending up at an annual rate of 5.3 percent, or by $425 million in total over the 12 years since 2008.

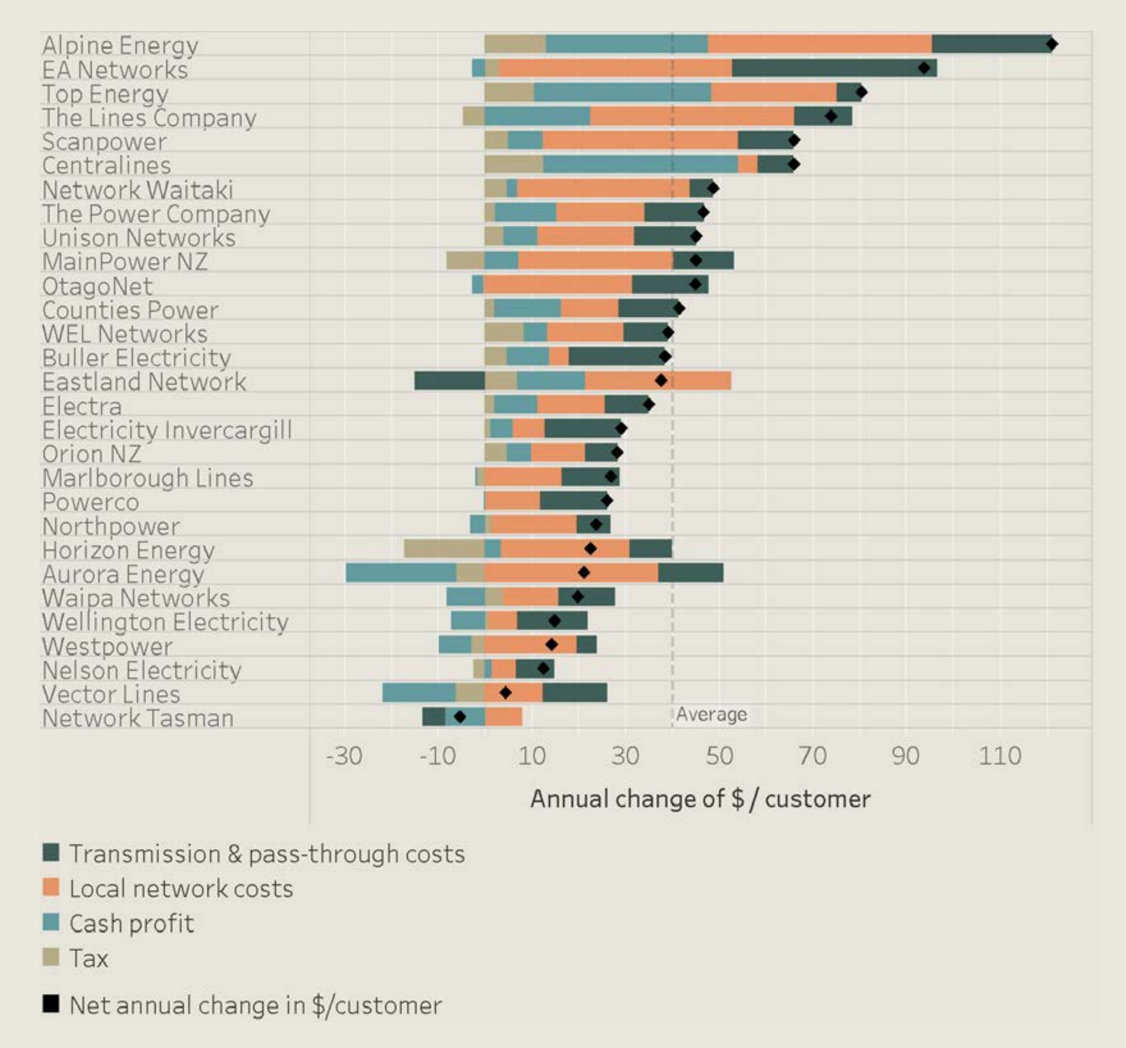
Cash profit has grown slowly in comparison, at an annual rate of 0.8 percent – less than the average rate of inflation – adding $50 million over the 12 years since 2008.

Tax has been largely static, reflecting the modest changes in profit combined with reductions in the corporate tax rate.[23]

23. The corporate tax rate was reduced from 30 percent to 28 percent from the 2011 tax year (ie, also ending 31 March).

The particular components exerting cost pressure differ for individual local lines companies. This is shown in Figure 9 for 2010-2020. Figure 9 gives the average annual per-customer increase in revenue for each local lines company.[24] This is broken down into the same components as the previous graphs. The figure 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 increase is given by the black diamond.

Figure 9: Trend in key cost categories in dollars per customer by local lines company, 2010-2020



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

Around half the increase in network prices is due to cost increases for transmission services

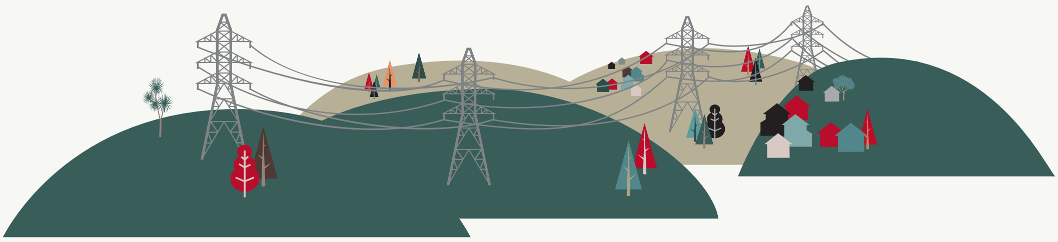
Around 30 percent of local lines companies' revenue has paid for the costs of services provided by other parties. These costs, which the local lines companies pass-through to customers without any mark-up, have been the fastest growing component of costs, responsible for close to half the total increase. In 2020, customers on average paid around $165 per year more towards these costs than they did in 2008.[25]

Around 89 percent 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 – its customers 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 7 percent of pass-through costs are from distributed generation.[26] 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 percent of pass-through costs are split amongst several other parties.[27]

Between 2008 and 2020, the costs that local lines companies have passed on from Transpower for transmission services increased from $415 million per year to over $700 million per year. This is shown in Figure 10.



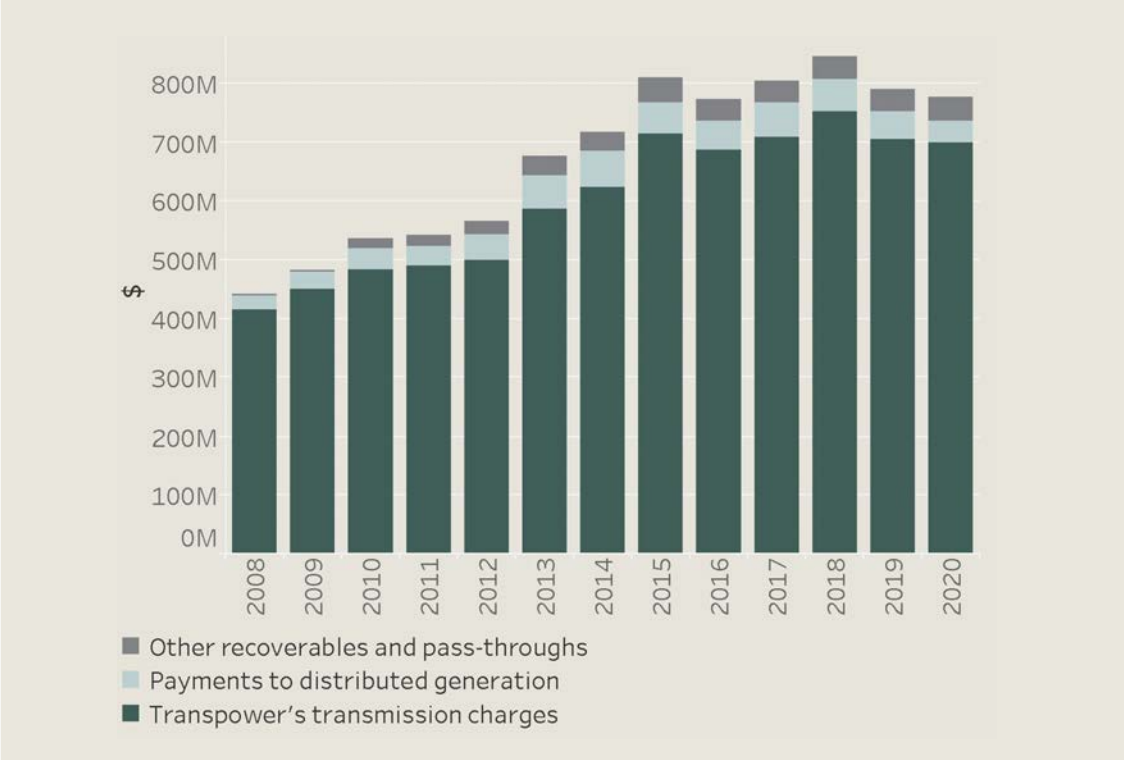
25. The the average increase in annual costs per customer is based on the trend in costs rather than a direct comparison of 2008 and 2020.

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

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

Figure 10 also shows that payments to distributed generators have increased materially – from $20 million in 2008 to over $60 million in 2014, though they subsequently decreased again to $35 million in 2020.[28]

Figure 10: Total transmission, distributed generation and other pass-through costs, 2008-2020



The costs passed through from Transpower have increased to allow Transpower to pay for several major capital projects that it carried out during the period. These projects were approved by the Electricity Commission, after a period of low investment and in anticipation of increasing or shifting generation and demand.[29] In particular:

- the 'North Island Grid Upgrade' project cost around $900 million and was approved in 2007 and commissioned in late-2012;
- the 'HVDC pole 3' project cost $670 million and was approved in 2008 and commissioned in mid-2013; and
- the 'North Auckland and Northland' project cost $470 million and was approved in 2009 and commissioned in early-2014.

In total, between 2008 and 2020 the value of Transpower's regulated asset base more than doubled – increasing by around $2.5 billion in nominal terms.[30]

28. 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 (ie, economic costs) would no longer receive these payments under regulated terms.
29. 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.
30. 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.

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. The costs of shared assets are allocated across transmission customers based on their contribution to periods of peak demand on the transmission network.[31] Because Transpower's increased costs are shared broadly across local lines companies, the average customer represented by each local lines company will have been impacted similarly.

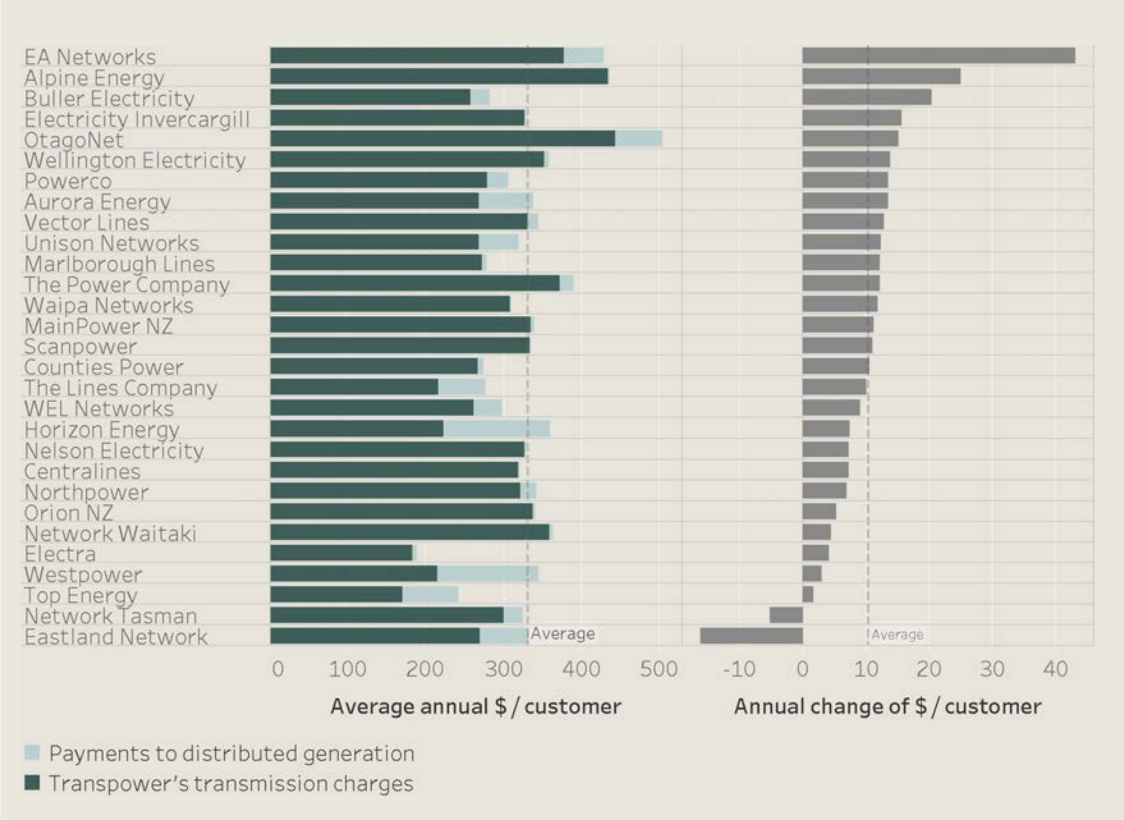
However, it will not have been a homogenous impact because there have been changes in the extent to which local networks rely on the transmission system when it is experiencing peak demand. Peak demand on the transmission system has remained broadly the same throughout the data period, but increased contributions to peak demand from some local lines companies have been offset by decreased contributions from others.[32] 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.

31. 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 are expected in the future, following recent changes to the transmission pricing methodology guidelines by the Electricity Authority.
32. Based on Transpower's reporting of New Zealand peak grid demand. See section 3.1 of https://www.transpower.co.nz/sites/default/files/publications/resources/Transmission%20Planning%20Report%202019.pdf

Figure 11 shows the average cost of transmission services – including Transpower charges and payments to distributed generation – for each local lines company between 2010 and 2020 (left-hand side). It also shows the annual rate of change in these costs (right-hand side) implied by the trends over 2010-2020.[33] 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.

Figure 11: Average transmission cost per customer, and change in that cost over time by local lines company, 2010-2020



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 also shows that all but two local lines companies have had costs per customer increase over the period. Both Network Tasman and Eastland have 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.

33. 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.

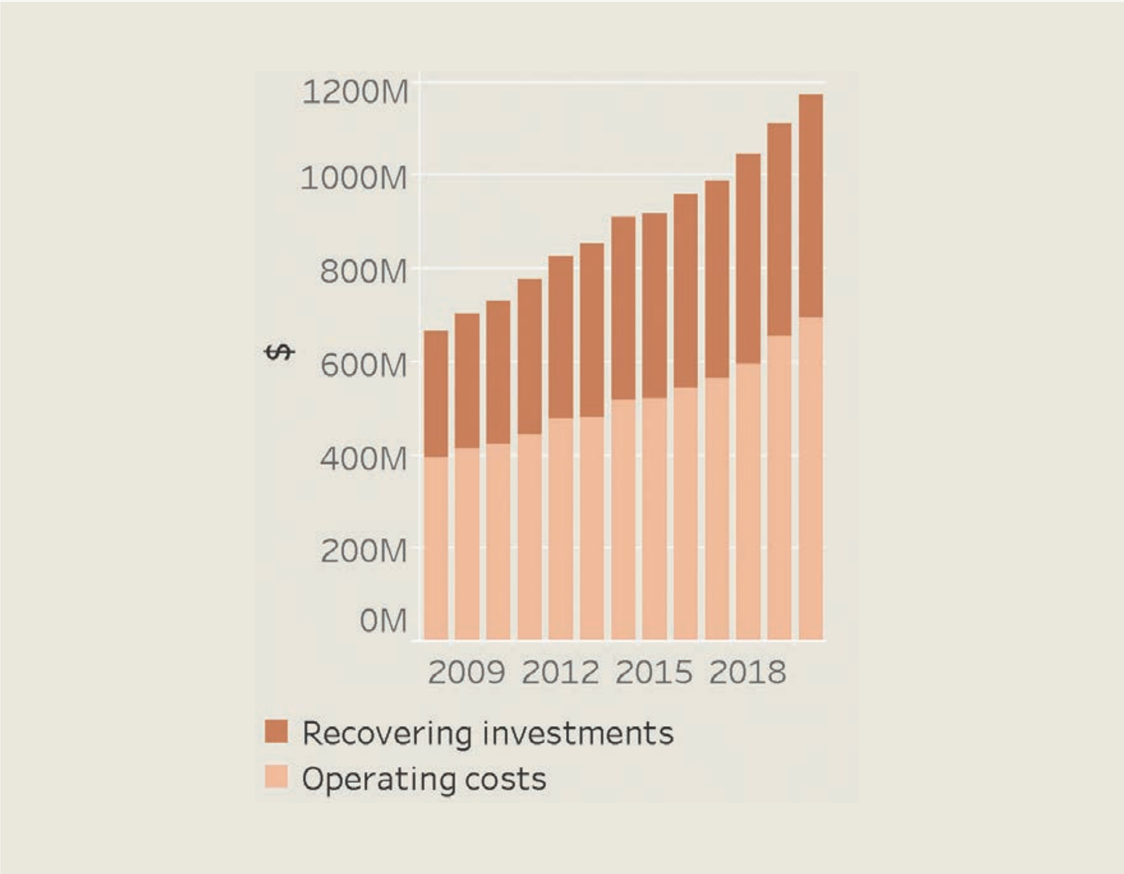
Customers are paying more to recover higher local network costs

Around 39 percent of local lines companies' revenue was required to recover the companies' own costs associated with their networks. Local network costs can be split into two further sub-components, which have both grown steadily over time:

- **Recovering investments**: Around 42 percent of local lines companies' own costs (17 percent of total revenue) related to recovering the cost of investments in their networks that were made to support growth and ensure healthy assets.
- **Operating costs**: Around 58 percent of local lines companies' own costs (23 percent of total revenue) related to running their businesses and operating their networks day-to-day.

The breakdown into these sub-components and change over time is shown in Figure 12.

Figure 12: Aggregate network costs by sub-component, 2008-2020



Local network costs are higher because of increased investment in local networks

Around 42 percent of local lines companies' own costs allowed them to recover the costs of investments they have made in their networks.

The total value of local lines companies' regulated asset base reached $13.0 billion in 2020, having increased by $6.0 billion since 2008.[34]

This increase reflects $9.3 billion of new assets that were commissioned (including purchased assets) and gains in the value of assets of $2.2 billion, partially offset by $4.9 billion of depreciation of the asset base over time.[35]

Local lines companies need to invest in new assets to support growth in and the health of the network. 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.[36]

Table 1: Mapping of categories and purpose of expenditure

Category used	Capital expenditure category in ID	Purpose of expenditure
Ensure network health through replacement and improvement	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 network growth	Consumer 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
Non-network	Non-network	Support distribution services but not part of the network itself
Other	Asset relocations	Moving existing assets in response to a request
	Costs of financing and value of vested assets	Technical adjustments

Local lines companies recover the cost of their investments over the life of the assets through depreciation, and this is what is reflected in the lines charges paid by customers.[37]

34. Based on 2020 data as disclosed, including a significant change to disclosed asset value from a related-party sale and lease-back transaction by Vector Lines.
35. Plus minor changes for asset disposals, lost and found assets and reallocated assets.
36. This is a shorter period due to data limitations, as not all capital expenditure was allocated to a category in 2008 and 2009.
37. Depreciation does not allow for a return on the capital cost of investments, which is captured in profit, discussed later.

Depreciation has remained at a fairly consistent proportion of the total regulated asset base since 2010, as shown by the line in Figure 14. This suggests there is no 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.[38]

The increase in depreciation has been faster than customer growth. Based on the trend, each customer on average pays around $63 more per year now than they did a decade ago for local lines companies to recover investment costs. Figure 14 gives the average amount of depreciation recovered per customer.

Figure 13: Investment in assets, 2010-2020[39]

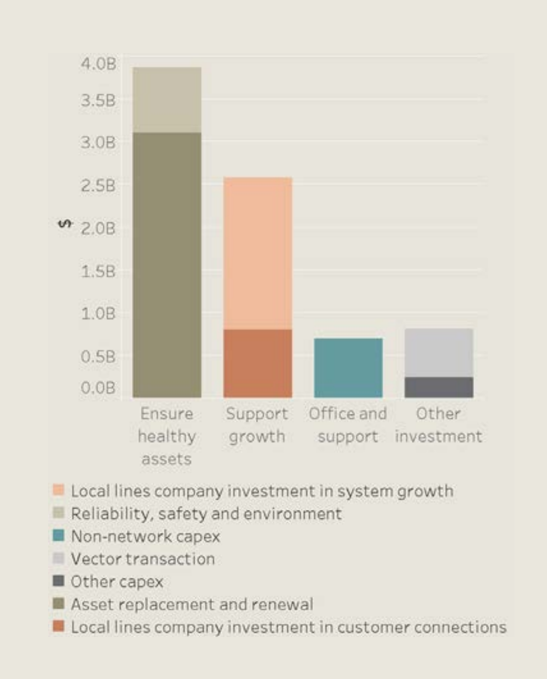
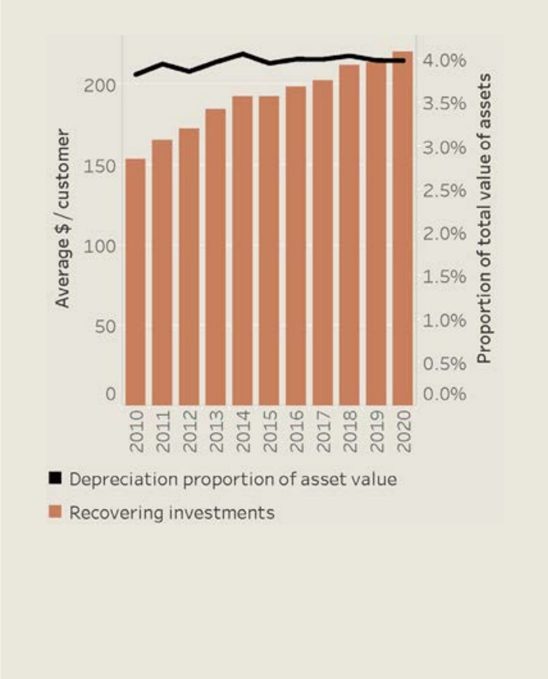


Figure 14: Total depreciation per customer and as a proportion of total value of assets, 2010-2020



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

39. Note reduced time-period. Local lines company investment totalled $6.6 billion between 2010-2020.

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 networks. Figure 15 shows, for each local lines company, the average depreciation cost per customer between 2010 and 2020 (left-hand side), and annual change in this metric implied by the trend (right-hand side).

Figure 15: Trend in depreciation in $/customer by local lines company, 2010-2020

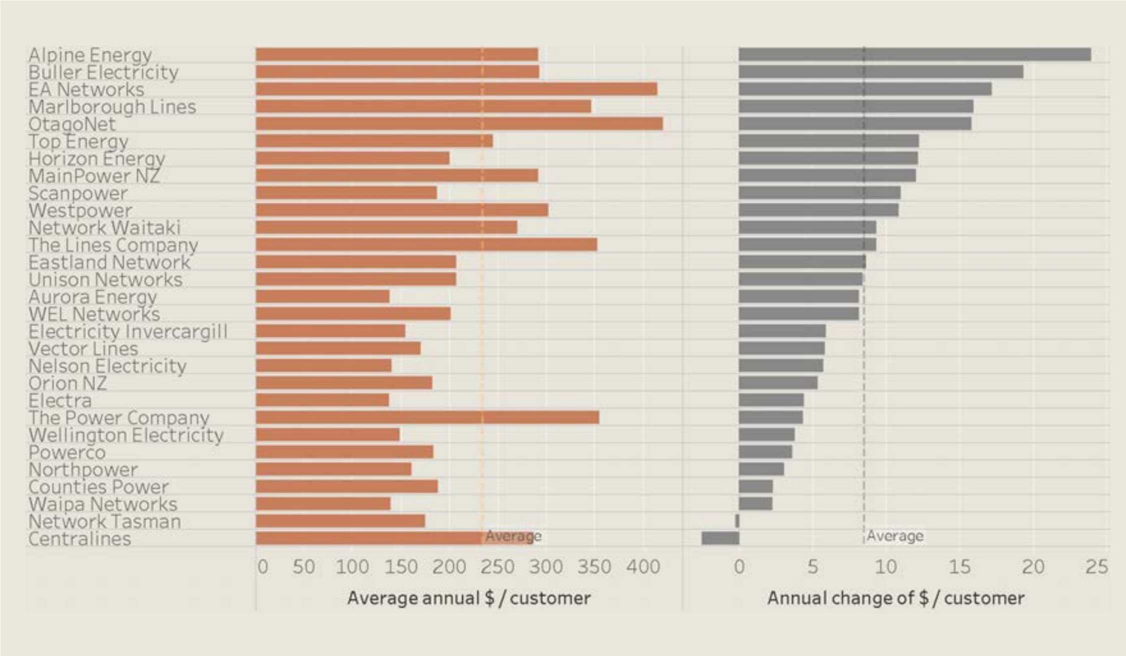


Figure 13 showed that around a third ($2.6 billion) of the investment that local lines companies made in their assets between 2010 and 2020 was for supporting network growth.

Customers themselves invested a further $1.0 billion to partially cover the costs of the assets necessary for them to connect to the local network or increase their demand.[40] Local lines companies are allowed to require customers to contribute financially to the 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 for determining the level of contribution.

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

40. They may face further costs for assets on their own property.

Figure 16 shows aggregate expenditure on consumer connections since 2010, including the investment by local lines companies and the contributions made by customers.[41] Figure 17 also shows these same costs spread across the new connections that were added.

Figure 16: Consumer connection expenditure and customer contributions, 2010-2020

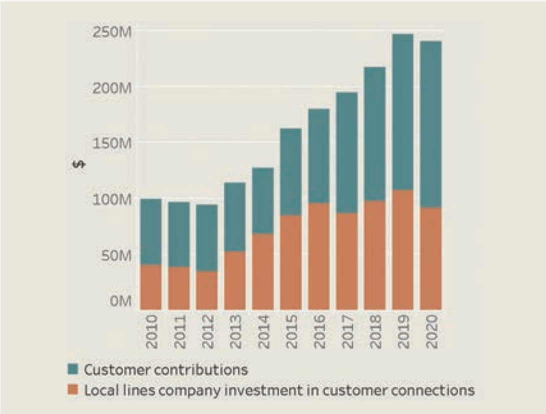
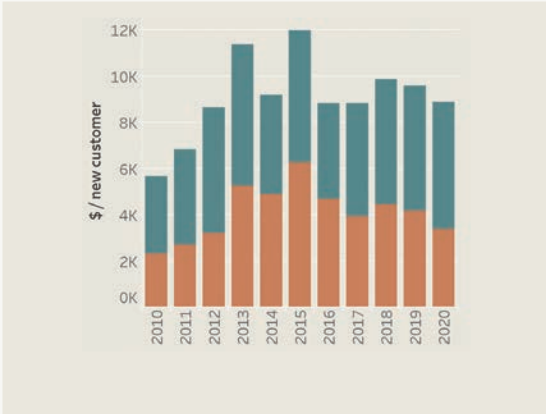


Figure 17: Consumer connection expenditure and customer contributions per new connection, 2010-2020



The graphs show that consumer connection expenditure has ramped up progressively since 2012. This appears to be driven by an increase in activity given that the average total cost of new connections has remained roughly the same during that period of growth.

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.[42]

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 18 and Figure 19 show the local lines companies' 'system growth' expenditure in total and per new connection.[43]

These graphs highlight a 'bubble' of expenditure for system growth between 2013-2016. Around 60 percent of this expenditure was invested in zone substations and sub-transmission assets.

Figure 18: System growth expenditure, 2010-2020

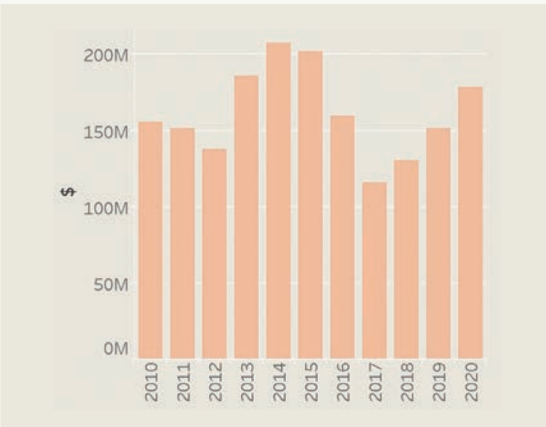
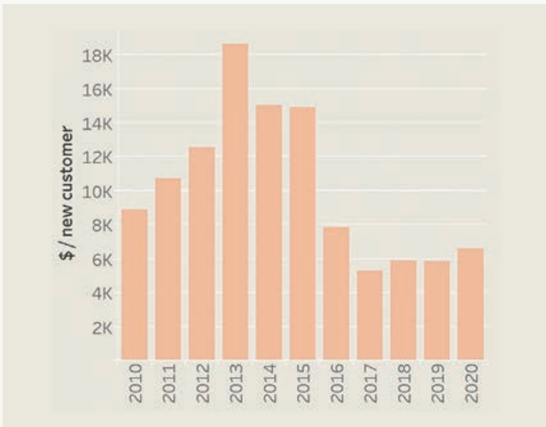


Figure 19: System growth expenditure per new connection, 2010-2020



41. We have estimated the share of the investment met by capital contributions for 2010 to 2012, assuming that the proportion of total capital contributions that are for consumer connection has remained consistent through-out the data period.
42. Capital contributions are treated 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.
43. We have excluded from this analysis a significant related-party sale and lease-back transaction that was disclosed by Vector Lines under ID in 2020 in order to observe long-term trends.

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

Figure 20: Capital expenditure for system growth per additional connection, between 2010-2020

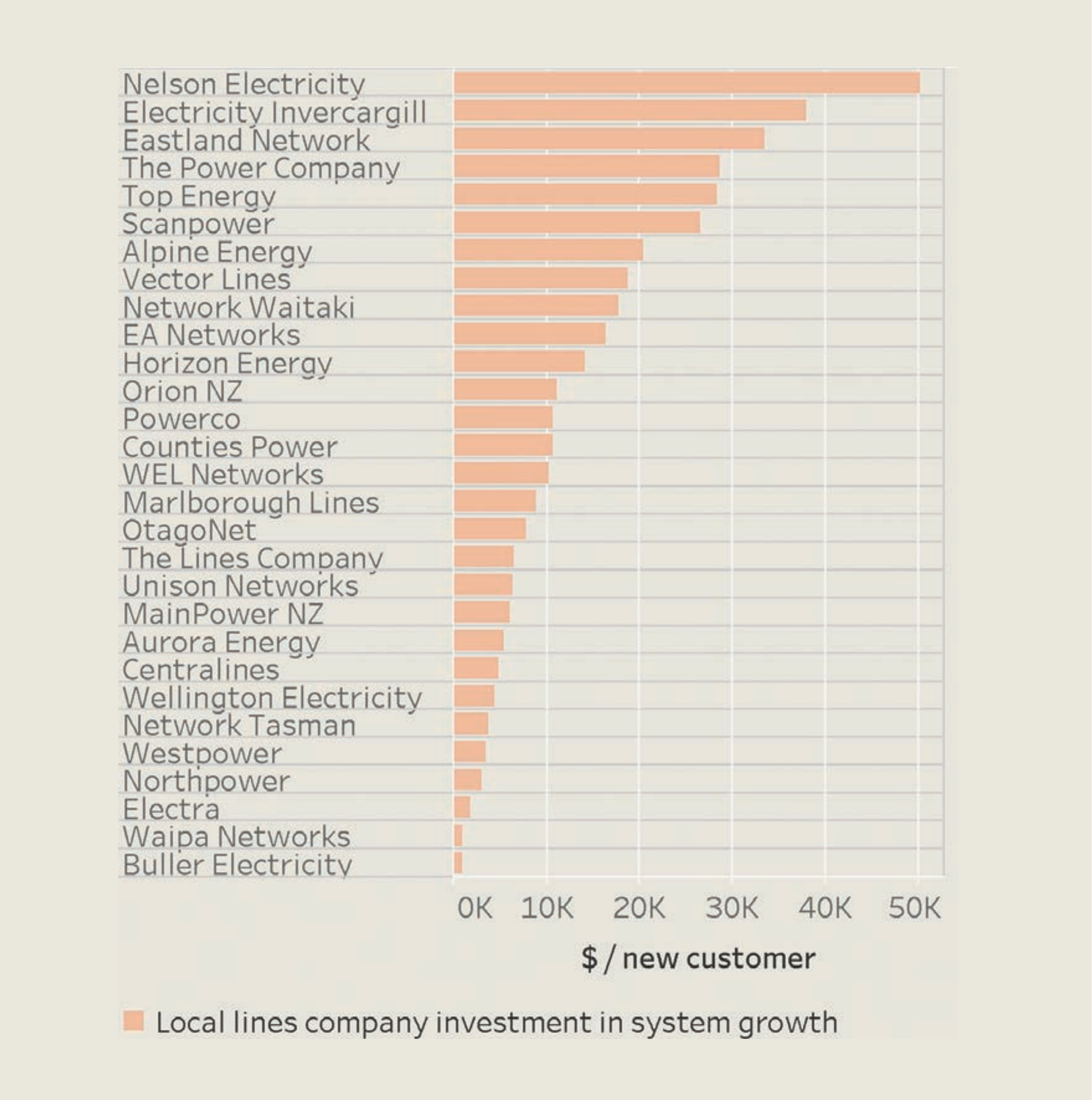


Figure 20 highlights that several local lines companies have significant expenditure on system growth relative to that for additional connections. This suggests they have been in a period of reinforcing shared assets that had been nearing capacity.

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 customers.[44] New individual customers may not always cover the full incremental costs of their additional demand, which may instead be shared quite broadly. Investment increments tend to be much larger than the increment in demand that necessitated them. Further, local lines companies may not always be able to identify specifically which customers benefit from, or cause a need for network reinforcement.

As examples, 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.

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 things like 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 in Figure 21. 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 21: Value of non-network assets within regulated asset base for all local lines companies, 2008-2020

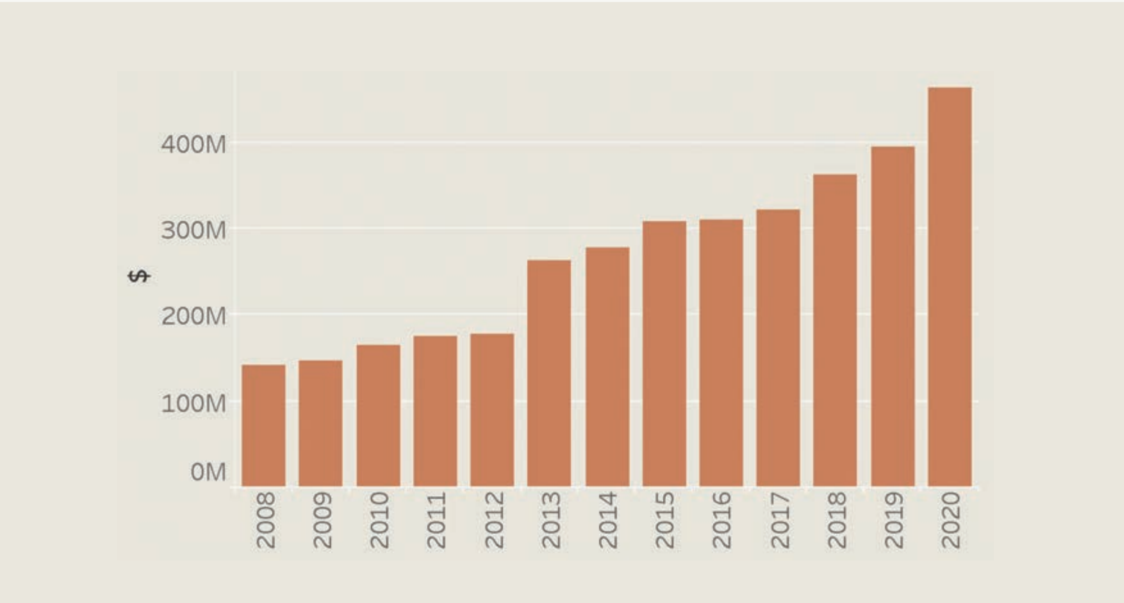


Figure 21 shows that the overall value of assets deemed to be non-network assets has increased in absolute terms by around $250 million since 2008, or 280 percent in total.

Figure 22 shows the investment made in non-network assets by local lines companies between

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

2013 and 2020. It uses dollars per customer for easier comparison between local lines companies and breaks the expenditure down further into categories of assets.[45]

Figure 22; Average capital expenditure on non-network assets by local lines company and asset category, 2013-2020

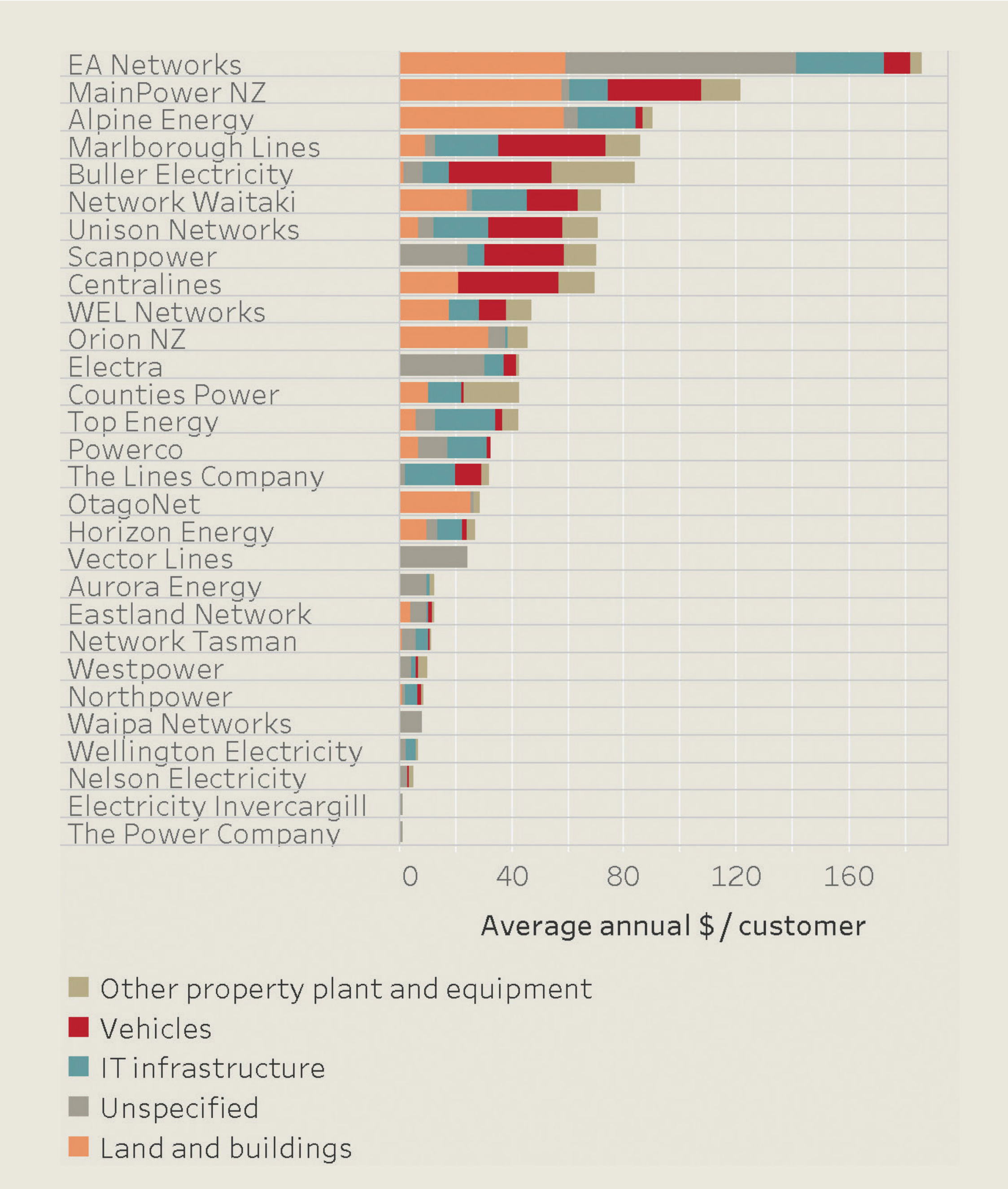


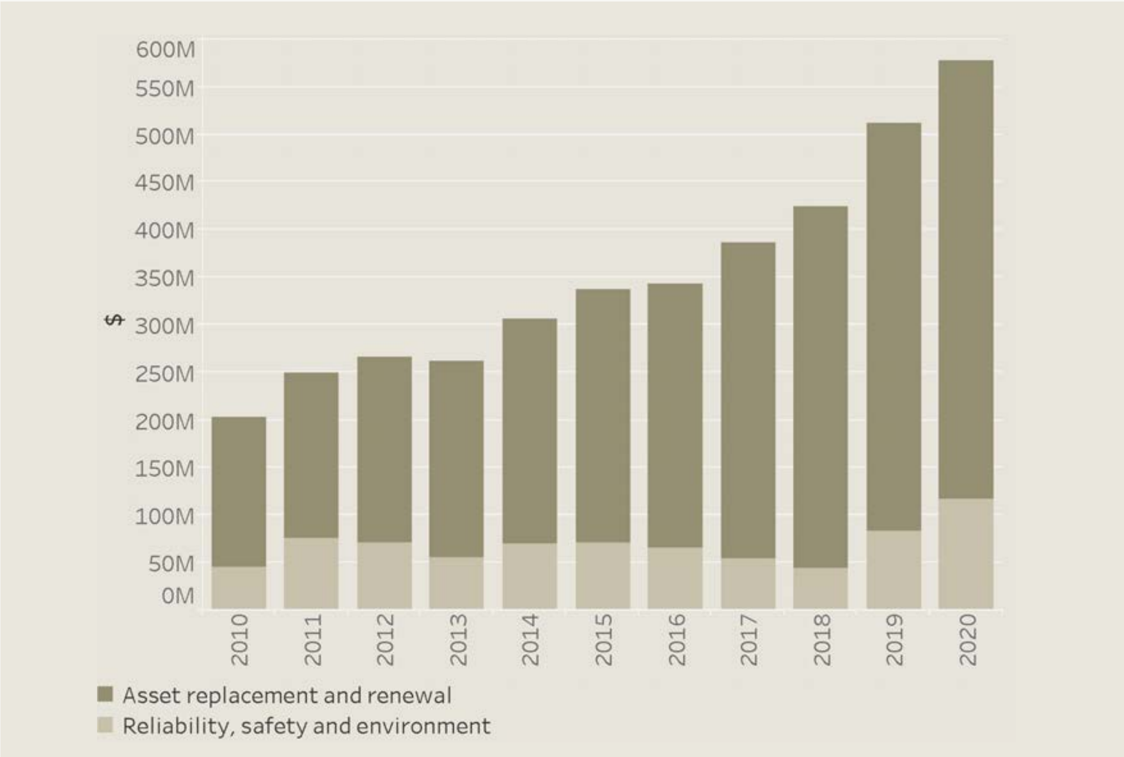
Figure 22 highlights that some local lines companies have made big investments relative to their size in non-network land and buildings, which is identifiable because the chart is given in expenditure per customer. This may mean they have been reacting to growth in their overall business size and capabilities. In some of these cases these may be one-off investments that are unlikely to be repeated in the foreseeable future, like a new head-office building or workshop.

Local lines companies have been investing to ensure healthy assets

45. 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.

About half ($3.9 billion) of the investments that local lines companies have made in new assets were to replace or improve their existing assets to ensure they remain safe and fit-for-purpose.[46] This investment occurred at an accelerated rate over the period. This is shown in Figure 23.

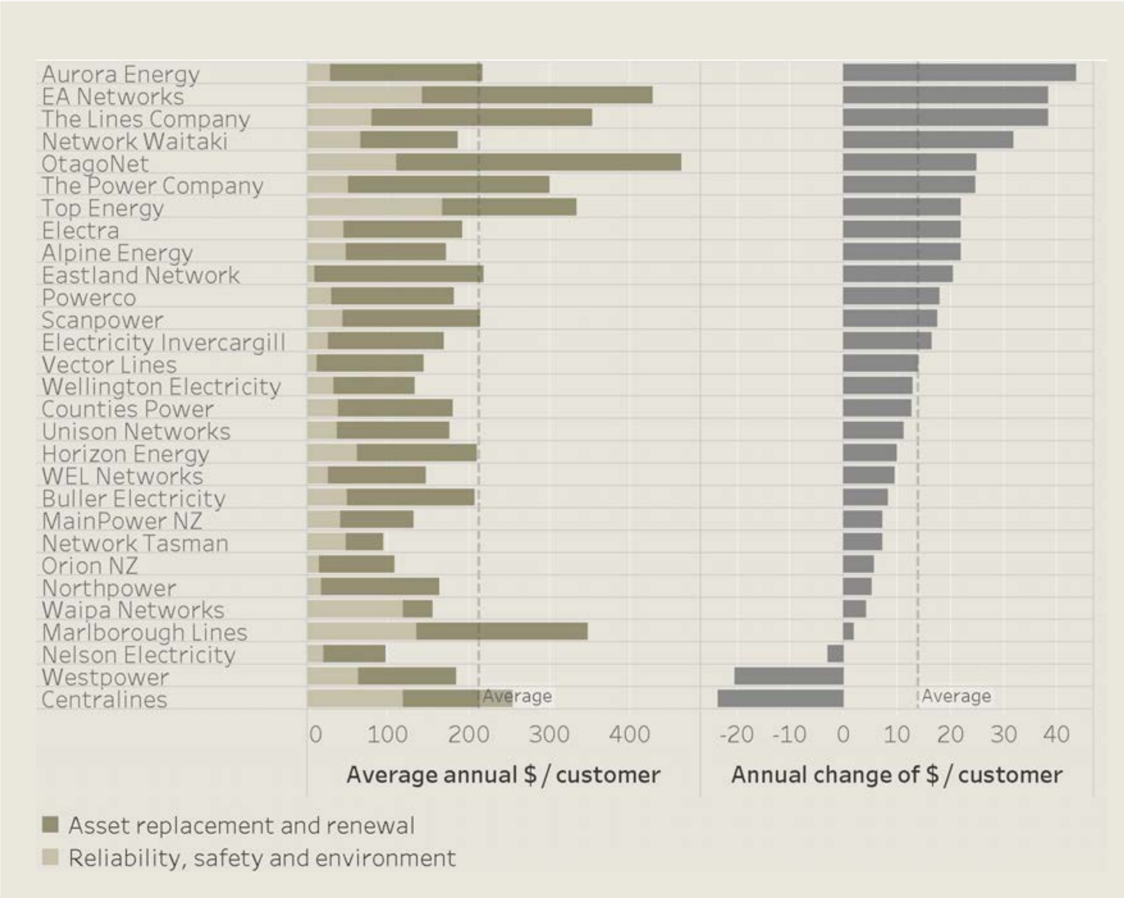
Figure 23: Capital expenditure to replace and improve existing assets for all local lines companies, 2010-2020



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 24, which gives the average replacement and improvement expenditure per customer for each local lines company between 2010 to 2020 on the left-hand side. The right-hand side shows the rate of change in this expenditure implied by the trend.

46. We have combined asset replacement and renewal expenditure and reliability, safety and environment expenditure in this section, as there is a blurred line between these categories, and variation in how individual local lines companies categorise them. Collectively we refer to them as expenditure to 'replace and improve' assets.

Figure 24: Average annual capital expenditure on replacement and improvement per customer, and rate of change, 2010-2020



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 some assets.

The right-hand side of the graph shows expenditure to replace and improve assets increased at an annual rate of $43 per customer per year for Aurora Energy. Another three local lines companies have rates of increase greater than $30 per customer per year, and a further six greater than $20 per customer per year. Aurora has applied for a customised price-quality path to enable it to continue a higher level of asset replacements. Powerco, Orion and Wellington Electricity successfully applied for customised price-quality paths during the period to allow for increased expenditure on replacing and improving their assets, including for resilience purposes.

The Commission has had concerns about the sufficiency of some local lines companies' replacement and improvement programmes. This was heightened following issues raised with Aurora Energy and further engagement with local lines companies.[47] Recent increased investment is unsurprising and may be of long-term benefit to customers. Our reviews of asset management plans have identified a welcome trend of more local lines companies moving toward a systemised and objective approach to their asset replacement programmes.

Figure 24 also shows three local lines companies whose renewal 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. This is suggested by their annual average expenditure being broadly in line with the industry average, despite the declining trend.

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, cost drivers and hence efficiency. We consider this is a potential subject of future work. This would support our priority for the sector of improving understanding about investment levels and associated incentives.[48]

47. See https://comcom.govt.nz/regulated-industries/electricity-lines/projects/aurora-energy-independent-review-of-the-state-of-the-network

48. We discussed our priorities for the sector in a November 2017 open letter. See https://comcom.govt.nz/__data/assets/pdf_file/0019/59311/Open-letter-on-our-priorities-for-the-electricity-sector-for-201718-and-beyond-9-November-2017.PDF

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

Around 58 percent of local lines companies' own costs allowed them to run their businesses and operate their networks day-to-day.

As shown in Figure 25, annual operating expenditure by all local lines companies reached $690 million in 2020, having increased from $395 million in 2008. The trend has been for local lines companies to recover around $110 more per customer per year to fund this expenditure.

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 between 2013 and 2020, which accounts for close to two thirds of the total increase in operating costs.[49] The changes are shown in Figure 26 for the following categories:

Table 2: Operational expenditure categories and purpose of expenditure [50]

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

49. 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 articially low in 2013.

50. For more specific definitions, see https://comcom.govt.nz/__data/assets/pdf_file/0025/78703/Electricity-distribution-information-disclosure-determination-2012-consolidated-3-April-2018.pdf

Figure 25: Breakdown of operating expenditure, 2008-2020

Figure 26: Components of operating expenditure and trends, 2013-2020

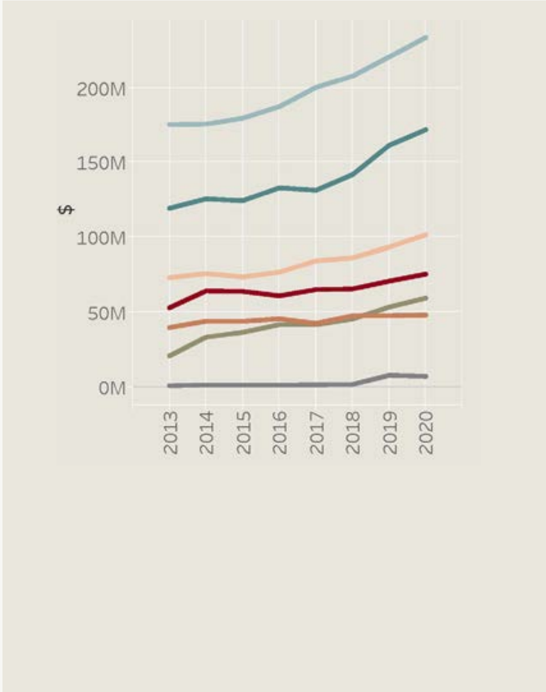


Figure 25 highlights that the increase in operating costs has been consistent over the full data period, and notably faster than network growth resulting in higher per-customer costs.

When we set price-quality paths for 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;[51]
- change with expectations of industry-wide changes in productivity; and
- increase for specific significant and uncontrollable step-changes in costs.

Between 2015 and 2020, 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, the factors driving higher operating costs were not completely the same as we anticipated. Inflation turned out lower than forecast, meaning that economy-wide cost pressures would not have driven higher costs to the extent we thought. However, other factors more than offset those savings.[52]

51. For setting the price-quality paths we used a combination of the Producer Price Index and Labour Cost Index to reflect the inflation pressure on local lines companies' operating costs.

52. See Attachment A of https://comcom.govt.nz/__data/assets/pdf_file/0020/191810/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2020-Final-decision-Reasons-paper-27-November-2019.PDF.

Figure 26 highlights that there were increases in the three biggest components of cost – being business support, system operations and network support, and routine maintenance. Vegetation management has also increased significantly, though it is a smaller contributor to total operating costs.

Figure 27 shows that the change in operating costs has differed significantly for different local lines companies, suggesting 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 2013-2020 period. This change is broken down into the same components as Figure 26. Increases in operating costs for a category extend to the right, while decreases in costs extend to the left. The net change is indicated by the black diamond.

Figure 27: Trend in operating expenditure categories in cost per customer by local lines company, 2013-2020

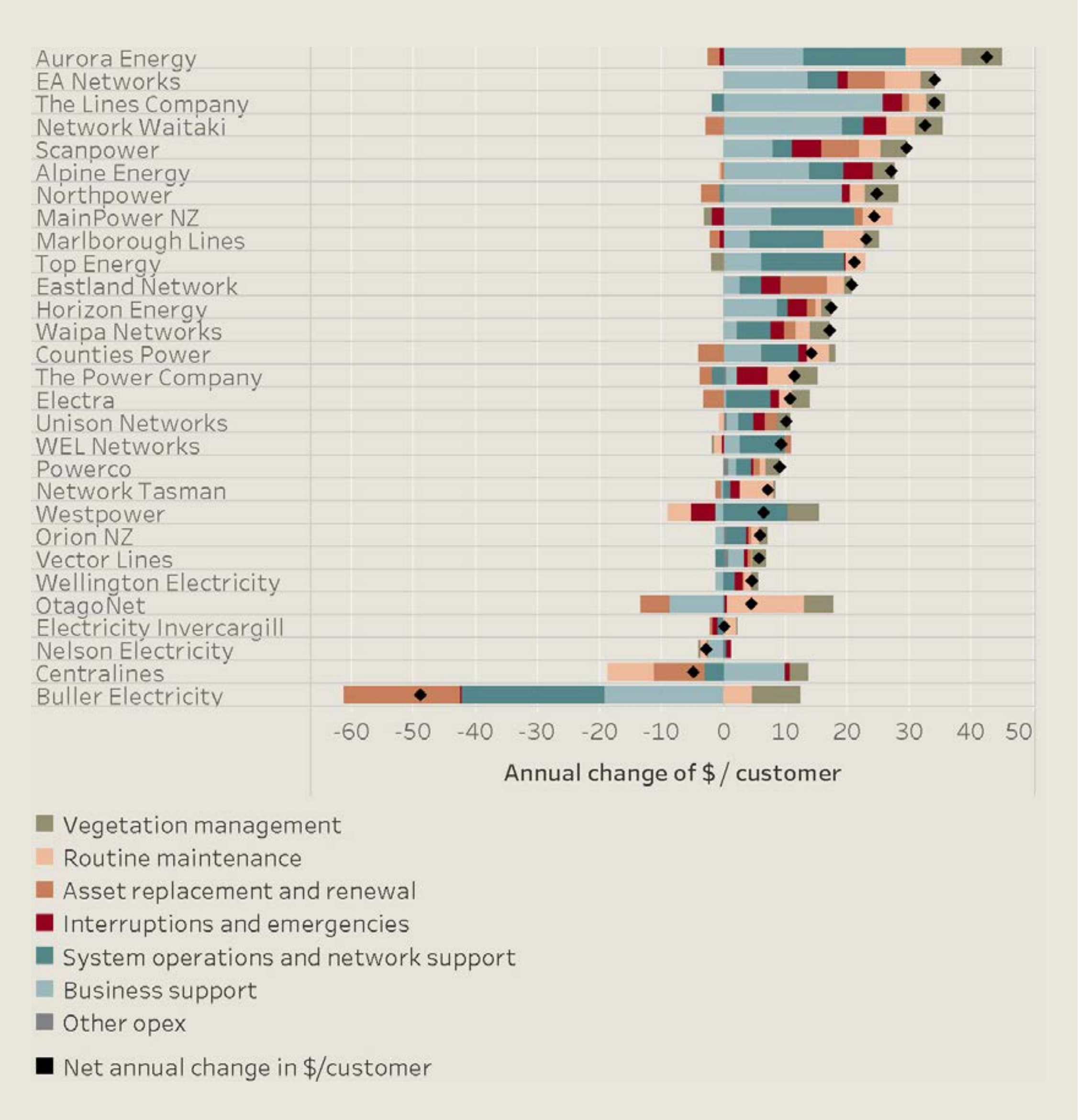


Figure 27 shows that all but four local lines companies have been spending more on operating their businesses day-to-day. Aurora Energy's operating costs increased the fastest, at a rate of over $42 per customer each year.[53] Conversely, Buller Electricity's operating costs declined by around $49 per customer each year, which we understand reflects a restructuring following the loss of revenue from a large customer.

The graph also shows that, while the categories driving 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 electricity distribution services.

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

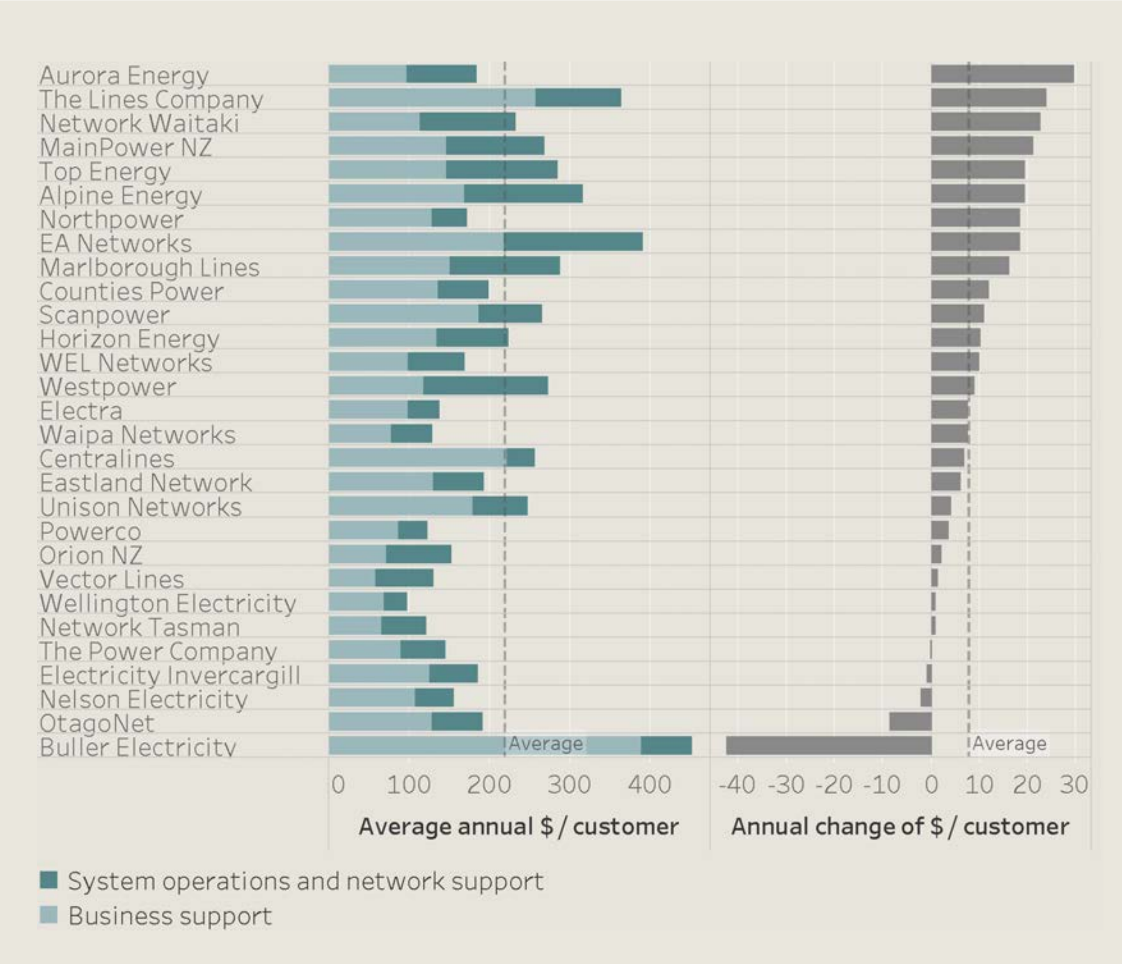
The two largest components of local lines companies' operating expenditure are for 'business support' and 'system operations and network support '– both considered non-network expenditure. These components respectively comprised around 35 percent and 24 percent of total operating expenditure from 2013 to 2020.

Business support operating expenditure relates to general corporate activities. Systems and network support operating expenditure relates to the design, management, and planning of the network, as well as interaction with customers. These categories of operating costs have been increasing at annual rates of 4.4 percent and 5.0 percent respectively since 2013. Overall, in 2020 customers on average paid around $42 more than they did in 2013 to support this expenditure.

All but two local lines companies have had increases in non-network operating expenditure, though there is a wide variation in changes. This is shown in Figure 28, which gives 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.

53. This is likely to be at least partially affected by their application for a customised price path (which they submitted in June 2020) and separation between the lines company and its contracting arm. See https://comcom.govt.nz/news-and-media/media-releases/2020/commission-receives-aurora-energys-application-to-increase-prices-to-fund-$383-million-network-investment-plan

Figure 28: Average annual non-network operating expenditure and rate of change in that expenditure by local lines company (2013-2020)



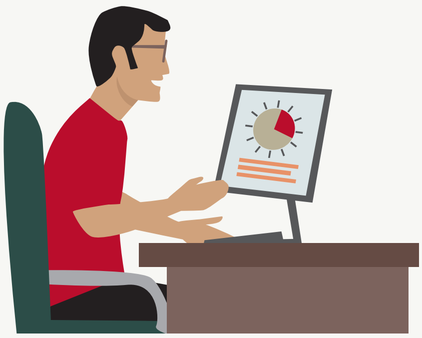
ID does not provide a further breakdown of these expenditure categories, and we are unable to readily analyse what specific factors caused them to increase.[54]

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

Higher insurance costs are one factor that has affected local lines companies' non-network operating expenditure, and we explicitly allowed for an increase in insurance costs within price-quality paths when we reset them in 2010. Local lines companies have suggested several other factors that may have been placing pressure on non-network operating expenditure, including:

- increasing regulatory requirements – notably including the need to meet stricter health and safety requirements – and an increased need to engage with regulators;
- changing customer demands;
- changes in technology, including industry-specific technology such as smart meters and network monitoring equipment, as well as information technology and technology services; and
- labour shortages.[55]

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.



55. 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 we gave local lines companies. However, we note that these issues did not meet the threshold required to be specifically included within allowances. See https://comcom.govt.nz/__data/assets/pdf_file/0020/191810/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2020-Final-decision-Reasons-paper-27-November-2019.PDF, page 164.

Local lines companies have been spending more to maintain their assets

Network assets require regular maintenance, including replacement parts.[56] Local lines companies must also keep lines free of vegetation to avoid unplanned outages. Figure 29 and Figure 30 show that local lines companies have been spending more on these activities since 2013.

Figure 29 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 30 shows total vegetation management expenditure (bars) and this expenditure per kilometre of power line (line).

Figure 29: Total operating expenditure on routine maintenance, and proportion of asset base, 2013-2020[57]

Figure 30: Total operating expenditure on vegetation management, and per km of power line 2013-2020

Figure 29 suggests that replacement and renewal operating expenditure has been flat, but routine maintenance spending has increased by around $28 million in absolute terms since 2013. 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.[58] Most spend between 0.5-2.0 percent 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 30 show that expenditure on vegetation management has increased by around $39 million or 88 percent 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 that 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.[59] In conducting our ongoing analysis of asset management practices and asset management plans, we assessed that the major driver of this higher spending is likely to be that local lines companies have been engaging in more comprehensive management of vegetation in the vicinity of existing lines, and thus devoting more resources toward it.

56. 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.
57. Value of the asset base at the start of the year.
58. This will be made available on the Performance Accessibility Tool.
59. Local lines companies disclose the length of power line on their network that specifically requires vegetation management. However, this data is of varying quality, so we have chosen not to rely on it in our analysis.

Despite the increased spending on both vegetation management and routine maintenance since 2013, there has only been a minor improvement 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 been worsening. This is shown in Figure 31. However, we note that the data series here is short relative to the likely period over which we might observe the benefits of improved vegetation management and maintenance. Further, external events and the quality of reporting may have influenced these trends.

Figure 31: Average outages experienced by customers that were caused by defective equipment and vegetation

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 32, 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 32: Average annual number of outages per customer and annual change in outages per customer caused by defective equipment and vegetation, by local lines company, 2013-2020

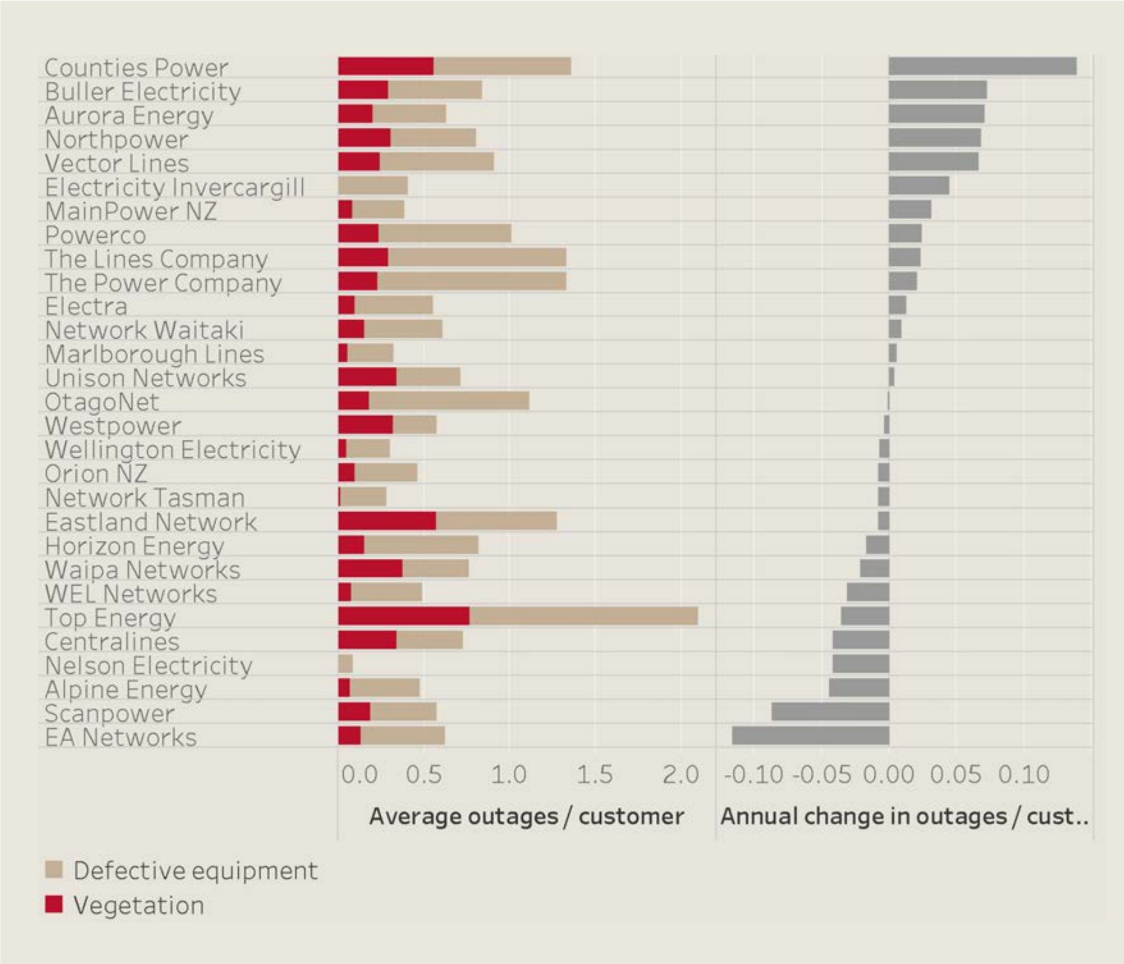


Figure 32 shows that around half of local lines companies have had a steady or declining number of outages per customer attributed to vegetation and defective equipment. However, increases by some large local lines companies influence the overall effect on customers seen in Figure 31 – most notably, Vector and Aurora Energy who have both faced Court-imposed penalties for breaches of the reliability standards we have set. Conversely, the local lines companies that have shown improvements in the number of outages per customer are comparatively small.

While not shown in the graph, in analysing the data we did not see an obvious relationship between changes in each individual local lines company's expenditure and the number of outages per customer for either vegetation or defective equipment. This seems counter-intuitive, but may reflect:

- limitations of the data - including that the data series is relatively short;
- that there is a mixture of preventative and reactive expenditure;
- that outages caused by vegetation or defective equipment may be exacerbated by transitory external events such as storms; and/or
- that other network characteristics influence both outages and expenditure in a way that clouds any expected relationship.

Further, expenditure on assets for replacement and improvement will also impact the incidence of outages by defective equipment and may potentially be a stronger driver of reliability outcomes.

We note there may be future changes to requirements for vegetation management expenditure. The Ministry of Business, Innovation and Employment is currently reviewing the Electricity (Hazards from Trees) Regulations 2003, which cover the trimming of trees near power lines, from both a safety and reliability perspective. The review is being progressed because, while tree owners consider the regulations work well, those involved in vegetation management consider they do not work well, for several reasons. While it is too soon to speculate on the outcomes of the review, they may change the extent, allocation of responsibility for, and costs of vegetation management.

The costs to restore power after an outage have declined

The number of unplanned power outages has trended upwards at an industry level since 2010 (discussed further later). However, the costs of restoration have changed much less quickly. This is shown in Figure 33, which gives the total operating costs for 'emergencies' across the industry (bars), and the total number of unplanned outages (line). Combined, this means the restoration costs-per-outage have trended down, as shown in Figure 34.

Figure 33: Total operating expenditure for emergencies versus unplanned outages, 2010-2020

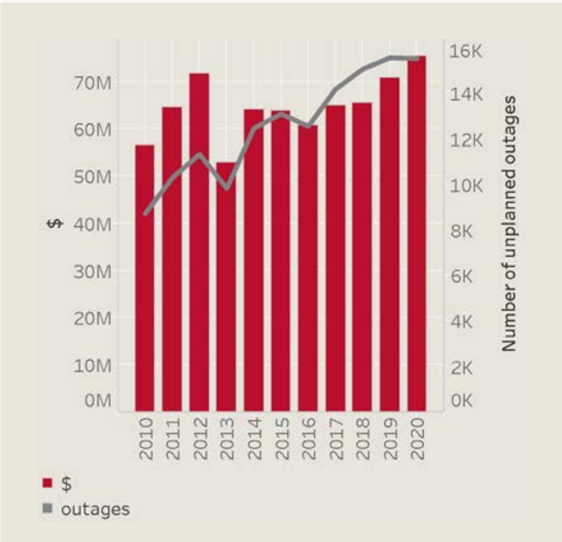


Figure 34: Average emergency opex per unplanned outage and trend, 2010-2020

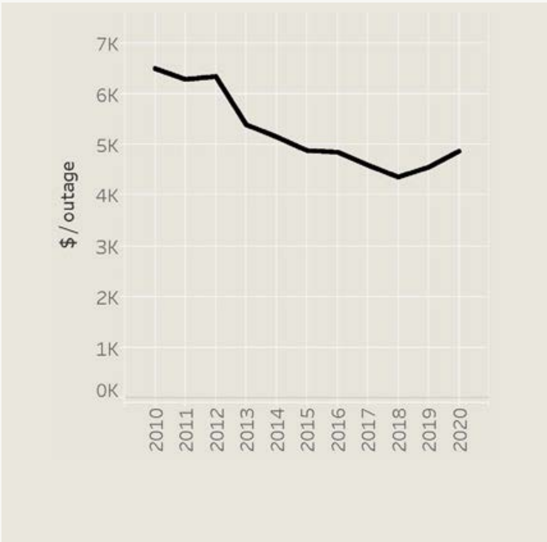


Figure 35 shows how the average restoration costs have changed for each individual local lines company. The colour of the bars indicates the total number of unplanned outages across the full period, with a darker bar indicating relatively more outages.

Figure 35: Rate of change of per-outage expenditure on 'emergencies' by local lines company, shaded by number of outages, 2010-2020

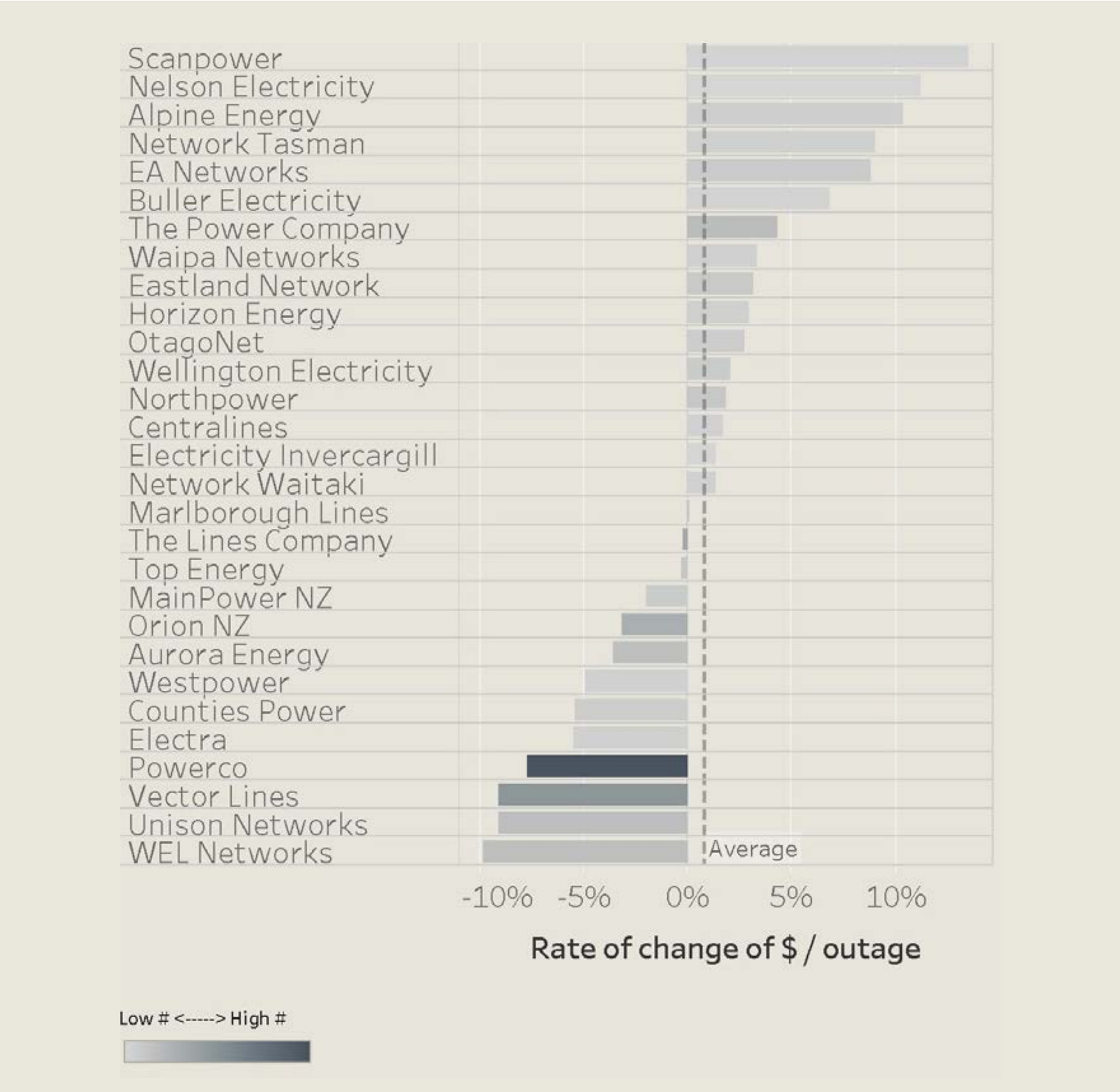


Figure 35 shows that the trend of decreasing outage restoration costs is not universal across local lines companies, with some local lines companies showing significant cost increases and others, significant declines. However, the larger local lines companies have tended to have costs decline, and these local lines 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.

Customers on average pay the same amount toward local lines companies’ profit which was not excessive

Collectively, local lines companies earned $775 million in total regulatory profit after tax in 2020. This is the total profit we recognise under our regulatory rules as reported under ID requirements. Regulatory profit excludes any profit the local lines company might earn from other business interests. The profit in 2020 consisted of:

- $480 million in cash profit
- $295 million of non-cash asset revaluation gain (in line with inflation).[60]

The change in profit and the breakdown over time is shown in Figure 36.

Figure 36: Total regulatory profit after tax for all local lines companies, 2008-2020

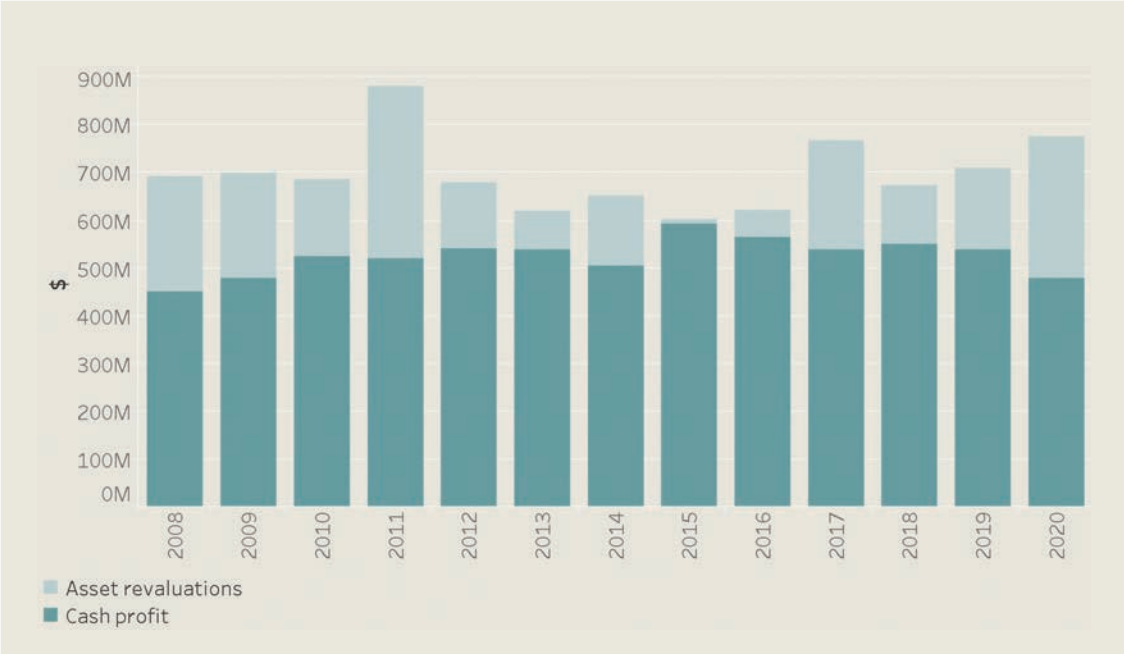


Figure 36 shows that the overall trend in total profit was relatively flat between 2008 and 2020. However, there was a dip from 2013 to 2016.

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 36 shows that cash profit (the teal bars) trended gradually upwards at an industry level between 2008 and 2015 before declining somewhat.

60. This is a 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 regualtory asset base, and are recovered slowly over time in future years through depreciation.

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 inflation has also increased the value of assets. Local lines companies are incentivised to invest because they can earn a return on their investments, which is their cash profit.
- Offsetting this, reductions in interest rates meant the cost of capital to invest reduced, which we reflected in the return we allowed price-quality regulated local lines companies to earn on their investments. This meant that cash profit in later years did not need to be as high to ensure fair compensation to local lines companies for their investments.
- Six 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 six 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 increased by around 0.8 percent per year, or 10 percent over the 12 years since 2008. Given the growth in customers, this has meant that each customer on average paid the same in 2020 than they did in 2008.

While outside the period of this analysis, we note that further declines in interest rates significantly affected the revenue we set for price-quality regulated local lines companies under the price-quality paths that apply from 1 April 2020 to 31 March 2025. However, we note that when interest rates eventually increase again, these would flow through to a higher cost of capital. A higher cost of capital would allow price-quality regulated local lines companies higher cash profit, placing upward pressure on prices.

The non-cash gains from asset revaluations (the light bars in Figure 36) represents 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.[61] Over the period since 2008, the revaluation of assets has been variable but consistent with measured inflation.[62]

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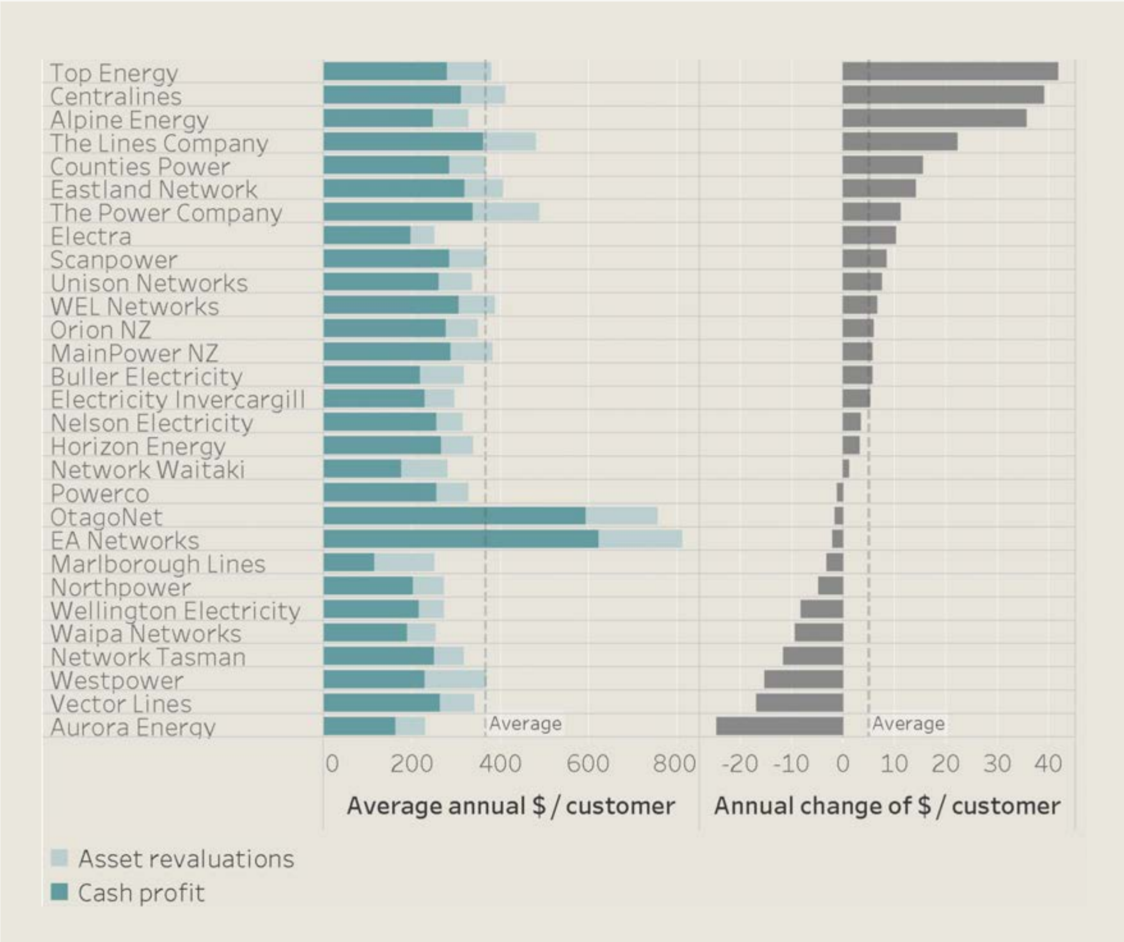
61. This is because line charges are set with regard to the value of the asset base, to provide for a recovery of investment through depreciation and also a return on that investment.

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

123. Despite total profit having declined over the period at a total industry level, there are differences in results between different local lines companies. Figure 37 shows the average annual profit per customer, using the same breakdown as in Figure 36 (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 37: Average annual total profit after tax and rate of change by local lines company, 2010-2020



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. For example, EA networks had total assets of $13,600 per customer in 2020, while Wellington Electricity had total assets per customer of $3,700.

The right-hand graph shows that three local lines companies have had their total profit after tax trending up by more than $30 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, two price-quality regulated local lines companies have seen their total profit after tax trend down by more than $10 per year. Aurora Energy has had revenue that has grown slowly under its price path, though it has recently invested heavily after safety issues were identified on its network, with higher costs eating into profit. Vector's 2010 price-quality path (set in 2012 following High Court action) required a reduction in its allowable revenue to better align it with its actual costs.

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

Figure 38 shows the total regulatory profit after tax expressed as a percentage of the total value of assets between 2013 and 2020.[63] This is given for price-quality regulated local lines companies, exempt companies, and all companies, weighted by the value of their asset base.

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. A company's required rate of return is also known as its weighted average cost of capital.

We have not included these graphs for each local lines company in this report. However, these are available on our interactive dashboard.

Figure 38: Weighted average return on investment based on total value of local lines company assets, 2013-2020 [64]

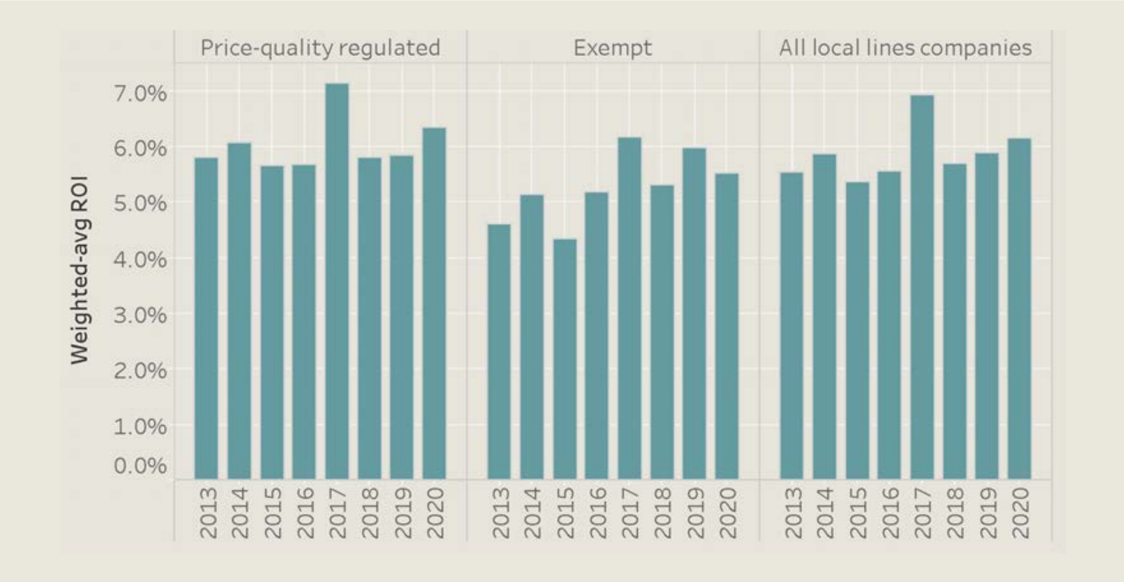


Figure 38 shows that return on investment has been increasing slightly for the industry in total.

The local lines companies that are exempt from price-quality regulation have had gradually increasing returns over the period but because the majority of the industry (in terms of asset value) consists of price-regulated local lines companies – which had stable returns over the period – the total industry result is still broadly stable.

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 percent for 2011 to 2015 and 6.4 percent for 2016 to 2020.[65] The industry returns were generally lower than these levels, suggesting that local lines companies were not collectively making excess returns.[66]

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63. The period of this analysis begins in 2013 given changes in the ID requirements which make earlier comparisons challenging.
64. 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.
65. 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 we used the 67th percentile. Our decision to use a lower percentile point of our estimate is explained in the relevant reasons paper on our website. See https://comcom.govt.nz/__data/assets/pdf_file/0029/88517/Commerce-Commission-Amendment-to-the-WACC-percentile-for-price-quality-regulation-Reasons-Paper-30-October-2014.PDF
66. 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 profitabilty.

Customers on many networks will have experienced some reduction in unplanned outages and restoration costs have declined

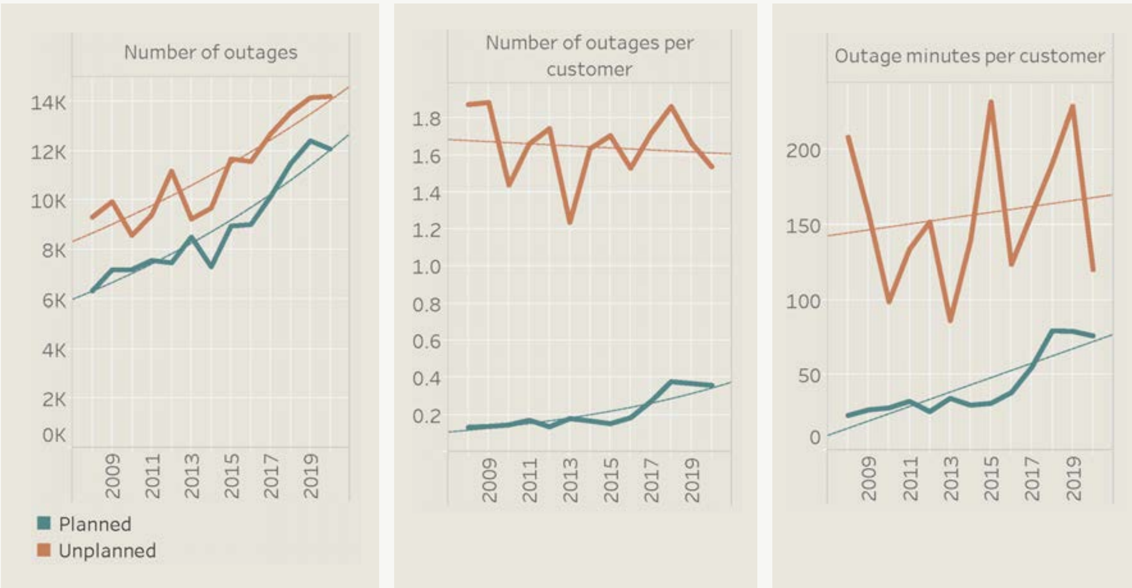
As well as looking at trends in the revenue and expenses of local lines companies, we have also analysed how the quality of the service they provide to customers has changed over time.

Figure 39 shows, for the whole country between 2008 and 2020, 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; and
- the total amount of time that each customer tended to have their power out for.

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 because of adverse weather and lightening, defective equipment, human error and third party, wildlife or vegetation interference. We have excluded outages caused by some major events from the analysis, such as the Canterbury earthquakes and particularly severe storms.[67]

Figure 39: Statistics of planned and unplanned outages, 2008-2020



From Figure 39 we can make three observations:

- There have recently 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, they 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 more likely to be planned.

67. 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.

We have identified two 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 we have set, and their customers make up a substantial proportion of the total customer base.
- Some local lines companies have recently 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 40 shows the trend in these same three metrics for each individual local lines company, for planned (left-hand side) and unplanned (right-hand side) outages between 2008 and 2020. The local lines companies are separated into those subject to price-quality regulation and those that are exempt, and then ordered from largest to smallest based on the number of customers on each local lines company.

Figure 40: Rate of change of number, frequency and duration of outages by local lines company, 2008-2020

Figure 40 shows that most local lines companies have seen increases in the number, frequency and duration of planned outages. With the exception of Powerco, the larger price-quality regulated local lines companies have also tended to have increases for unplanned outages. However, several smaller and exempt local lines companies have a reduced number, frequency or duration of unplanned outages.

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