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Initial observations on forecasts disclosed by 29 electricity distributors in March 2013

Date: 29 November 2013

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Executive summary

Purpose of paper

X1. Under Part 4 of the Commerce Act 1986, we are required to publish summary and analysis of the information disclosed by distributors. The purpose of summary and analysis is to promote greater understanding about the performance of distributors, their relative performance, and the changes in their performance over time.

X2. As we signalled on 6 September 2013, we are currently seeking to refine our approaches for analysing the asset management information disclosed by 29 distributors. Amongst other things, the information helps to identify whether distributors are operating and investing in their assets efficiently.

X3. To help identify any issues with our approach, and facilitate discussion, this paper sets out our initial observations on the expenditure forecasts disclosed in March 2013. We invite you to provide your views.

X3.1. A workshop with Commission staff is scheduled for 12 December 2013.

X3.2. Written responses are requested by 23 December 2013.

X4. Our initial observations will likely be of most interest to electricity distributors. However, we hope this paper will also be relevant to other stakeholders with an interest in the asset management of electricity distribution networks. By providing your views, you will help inform an updated piece of analysis due out next year.

Asset Management Plans—Disclosed in March 2013

X5. For a number of years, distributors have had to disclose the principal document that drives their asset planning decisions. In their 'Asset Management Plan', each distributor is required to describe the approach to risk management, consumer engagement, and the basis for making decisions on planned investments.

X6. In the past, our reviews of each distributor's Asset Management Plan have essentially assessed for compliance with the requirements.[1] The most recent assessment covered the planning period 1 April 2011 to 30 March 2021. That review concluded that compliance had generally improved relative to previous years.

X7. In future, other analytical approaches may potentially be suitable. For example, one option would be to review the governance processes and policies that are described by distributors in their Asset Management Plans.

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[1] Refer: Parsons Brinkerhoff New Zealand, 2011 Asset Management Plan Reviews, 26 August 2011. Available at: www.comcom.govt.nz/review-of-asset-management-plans/.

Initial observations based on existing analytical approaches

X8. Before considering alternative analytical techniques, we were interested in what our existing approaches could tell us about performance. In a price setting context, we developed a low cost model to forecast operating expenditure, and compared the predictions of that model to forecasts from 16 distributors.

X9. Although our existing model has already been tested through consultation, this is the first time we have applied the model to the industry as whole. We have therefore explained our approach in detail, so that other distributors can provide feedback about how the model has been applied, and how it could be improved.

X10. We have also suggested ways in which we could develop a similar model for certain categories of capital expenditure. We invite you to provide your views on these proposals. We are particularly interested in any issues you can identify before we develop the approach further.

Our initial observations—In brief

X11. As we explain in this paper, our view is that all distributors spend money for similar reasons. The three main 'drivers' are:

X11.1. Ownership – Owning assets creates on-going expenditure obligations that can be managed but not avoided, such as the costs of routine maintenance, vegetation management, and compliance with any laws and regulations.

X11.2. Health – Expenditure is required to ensure assets remain in sufficient health to provide a particular quality of service, either through maintenance of old assets, or replacement with new.

X11.3. Capacity – Expenditure may be required to keep pace with changes in the required capacity on the network as a whole, or at individual points, depending on the current and expected utilisation of assets.

X12. Across the industry, differences in the absolute level of spending can be explained, at least in part, by differences in the underlying drivers. For example, a large network will generally cost more to maintain than a small network. However, network characteristics are also relevant, such as network design, topology, and topography.

X13. Our expectation is that changes in expenditure could generally be explained by changes in the underlying drivers. For example, an increase in the number of assets owned by a distributor will tend to drive up the overall costs of maintenance. The size of any change may be affected by network characteristics, as well as other internal or external changes in the operating environment, eg, changes in laws and regulations.

Forecast changes in expenditure

X14. In this paper, we compare forecast expenditure to historic expenditure for each distributor. As can be seen in Table X1, we observe significant variation in the amount distributors forecast to spend relative to past levels. All changes are expressed in real terms, ie, before inflation is taken into account.

Table X1: Forecast change in expenditure (%)

Capital expenditure		Operating expenditure	
	2014-18 vs. 2010-13		2014-18 vs. 2010-13
Eastland Network	+142	Eastland Network	+33
Network Tasman	+110	Mainpower NZ	+29
Scanpower	+108	Electricity Invercargill	+27
Mainpower NZ	+51	Electricity Ashburton	+24
Waipa Networks	+49	Alpine Energy	+24
Orion NZ	+49	The Lines Company	+20
Horizon Energy	+42	WEL Networks	+18
Top Energy	+36	Orion NZ	+18
The Lines Company	+35	Unison Networks	+17
Counties Power	+33	Horizon Energy	+16
Aurora Energy	+29	The Power Company	+13
Electra	+28	Powerco	+13
OtagoNet	+26	Network Tasman	+13
Northpower	+26	Vector Lines	+13
Powerco	+24	Scanpower	+11
Wellington Electricity	+20	OtagoNet	+8
Network Waitaki	+17	Wellington Electricity	+8
WEL Networks	+14	Network Waitaki	+8
Nelson Electricity	+13	Westpower	+7
The Power Company	+12	Nelson Electricity	+4
Unison Networks	+8	Top Energy	+3
Vector Lines	+4	Counties Power	+1
Electricity Invercargill	−3	Northpower	−2
Electricity Ashburton	−6	Waipa Networks	−3
Marlborough Lines	−11	Centralines	−5
Alpine Energy	−15	Electra	−17
Centralines	−35	Marlborough Lines	−18
Buller Electricity	−36	Aurora Energy	−34
Westpower	−55	Buller Electricity	−63
Industry (excl. Orion NZ)	+16	Industry (excl. Orion NZ)	+9

X15. In total, 22 distributors are forecasting an overall increase in the average amount of operating expenditure from 2010-13 to 2014-19. Of these, 15 distributors are forecasting an increase of more than 10%, on average, each year.

X16. 22 distributors are forecasting an overall increase in capital expenditure. Of these, 15 distributors are forecasting an increase that is equivalent to more than 20%, on average, each year. However, seven distributors are forecasting an overall fall.

X17. To help people better understand the variation shown in Table X1, we identify in this paper:

X17.1. The categories of expenditure that are largest in dollar terms;[2]

X17.2. The drivers that affect each category; and

X17.3. The information available about each driver.

X18. We also provide the results of our modelling for operating expenditure, which partially explains the variation in the forecasts. In some cases, a more detailed understanding of a distributor's forecast is likely to be appropriate. In such cases, the distributor's Asset Management Plan provides additional information.

Initial observations on forecasts of operating expenditure

X19. In Chapter 2, for operating expenditure, we observe that the largest category of operating expenditure for 21 distributors in 2010-13 was the same as it was for the industry as a whole, ie, 'business support'. However, for five distributors, the largest category was 'system operations and network support'.

X20. 'System operations and network support' is the category that is generally forecast to increase by a greater amount than any other category:

X20.1. 21 distributors forecast 'system operations and network support' to increase in real terms from 2010-13 to 2014-19; and

X20.2. 15 distributors expect this category to increase more in dollar terms than any other category.

X21. However, other categories are more material for certain distributors. Five distributors expect 'business support' to increase more in dollar terms than any other category. For other distributors, 'routine and preventative maintenance' or 'asset replacement and renewal' is expected to be the main area of growth.[3]

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[2] In addition, in Attachment D, we provide a detailed breakdown of the expenditure forecasts for each distributor.

[3] Under GAAP, some components of asset renewals may be treated as operational expenditure, which explains why 'asset replacement and renewal' appears as both a category of operating and capital expenditure and potentially why this is reported as a relatively small category.

X22. In Chapter 3, we identify what we observe to be the links between the drivers in paragraph 0 and each category of operating expenditure. Table X2 provides a summary. Chapter 3 explains where you can find further information for each driver.

Table X2: Driver of each category of operating expenditure

Category of operating expenditure	Ownership	Health	Capacity
Business support	•		
Routine and corrective maintenance and inspection	•	•	
System operations and network support	•	•	•
Service interruptions and emergencies	•	•	
Asset replacement and renewal		•	
Vegetation management	•		

X23. In Chapter 4, we use our model of operating expenditure to observe whether the drivers of expenditure help explain each distributors forecast. In general, we forecast operational expenditure to be lower than distributor's own forecasts, but many of the forecasts are within 10% of our model.

X24. Differences between our model and each distributor's forecast could arise for a number of reasons. For example, we have not attempted to take into account the relative efficiency of each distributor. In addition, our existing model extrapolates historic trends in network scale rather than relying on a forecast. A number of other improvements could be made if more information was available.

X25. We would expect that any evaluation of the difference between our model and the distributor's forecast should in the first instance consider specific details contained in the Asset Management Plans published by each distributor. Although detailed evaluation may be quite costly, certain reasons for differences will be more obvious than others.

X26. In Chapter 5, we analyse the input price assumptions that are implicit in each distributor's forecast. In general, for operating expenditure, we observe that distributors appear to assume that input prices will increase by 1-3% each year to 2018. These assumptions appear broadly consistent with an independent forecast by the New Zealand Institute of Economic Research for similar types of input.

Initial observations on forecasts of capital expenditure

X27. In Chapter 2, for capital expenditure, we observe that the largest category historically for 18 distributors is 'asset replacement and renewal', but for seven distributors it is 'system growth', and for three distributors it is 'reliability, safety and environment'. 'Consumer connection' is the largest category for one distributor.

X28. 'Asset replacement and renewal' is generally the category that is forecast to increase more than any other category:

X27.1. 24 distributors forecast 'asset replacement and renewal' to increase in real terms from 2010-13 to 2014-18; and

X27.2. 14 distributors expect this category to increase more in dollar terms than any other category.

X29. In addition, we observe that for certain distributors the forecast increase in other categories of capital expenditure are the more material in dollar terms.[4] These categories are 'system growth', 'reliability, safety, and environment', 'asset relocations' and 'non-network' capital expenditure.

X30. In Chapter 3, we identify what we observe to be the main drivers of each category of operating expenditure. Table X3 provides a summary. Chapter 3 also explains where you can find further information about each driver.

Table X3: Driver of each category of capital expenditure

Category of capital expenditure	Ownership	Health	Capacity
Asset replacement and renewal		•	
System growth			•
Consumer connection			•
Reliability, safety and environment	•	•	•
Non-network assets	•		
Asset relocations	•		

[4] One distributor, Westpower, is forecasting decreases in capital investments across all categories of capital expenditure.

X31. In Chapter 4, we invite views on how a high level model could be built to assess capital expenditure. Such a model could provide a high level prediction of the likely level of expenditure required on the network, or changes in expenditure relative to historic levels. These models could then be used to provide an indication of the likely efficiency and appropriateness of the distributor's forecast.

X32. While there are a number of methods by which a model could be developed for each of these expenditure categories, our observation is that two generic approaches are available: an 'adjustment method', and an 'absolute calculation'. These approaches are explained in Chapter 4 together with high-level examples of how they could be implemented for selected expenditure categories.[5]

X33. Finally, in Chapter 5, we analyse the input price assumptions that are implicit in each distributor's forecast. In general, for capital expenditure, we observe that distributors appear to assume that input prices will increase by 1-3% each year to 2018. These assumptions appear broadly consistent with an independent forecast by the New Zealand Institute of Economic Research for similar types of input.

Responding to this paper

X34. Chapter 6 of this paper provides details about how you can provide your view on this paper. Amongst other things, we set out the address for written submissions, and the arrangements for the workshop on 12 December 2013. The purpose of the workshop is to allow you to discuss the contents of this paper with Commission staff.

X35. By providing your views on this paper, you will primarily help inform an updated piece of analysis that we intend to publish next year on the same subject. In particular, the analysis in this paper relies solely on the information disclosed by distributors in March 2013.[6] Therefore, at a minimum, we anticipate updating our initial observations to incorporate the information that was required in August 2013.

X36. In addition, your views on this paper may help identify analytical improvements that could be relevant to the next reset of default price-quality paths. However, parties will have a separate opportunity to provide comments on our models at the draft decision stage in that process.

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5 Attachment A also contains some preliminary analysis of the information disclosed in March 2013 about the underlying drivers of the categories of expenditure that appear to be most material, namely: 'asset replacement and renewal', and 'system growth'.

6 The information required by 31 March 2013 included estimated expenditure for the disclosure year ending 1 April 2013. In this paper, we have treated these estimates as actual expenditure for that year, but we recognise that actual expenditure may in fact be different.

Working group established by the Electricity Networks Association

X37. Amongst other things, we hope that the observations in this paper would be relevant to the working group on forecasting approaches for default price-quality paths that has been established by the Electricity Networks Association. Nevertheless, Commission staff attend these working groups as observers only. The first outputs from this group are expected in the New Year.

X38. However, in our view, analysis of expenditure forecasts is relevant for all distributors, not just those that are subject to default price-quality paths. For example, the analysis helps promote understanding of the differences in the amount that each distributor is forecast to spend relative to historic levels.

Other observations contained in the attachments

X39. The attachments to this paper provide some initial observations on additional areas of performance. Attachment B discusses expected changes in the level of quality provided to consumers by each distributor, and attachment C provides initial observations of information disclosed in relation to energy efficiency, demand side management and reductions in losses.[7]

[7] The observations contained in these attachments may be relevant to the working group established by the Electricity Networks Association for quality of service, and the working group for energy efficiency, demand side management, and the reduction of losses.

1. Introduction

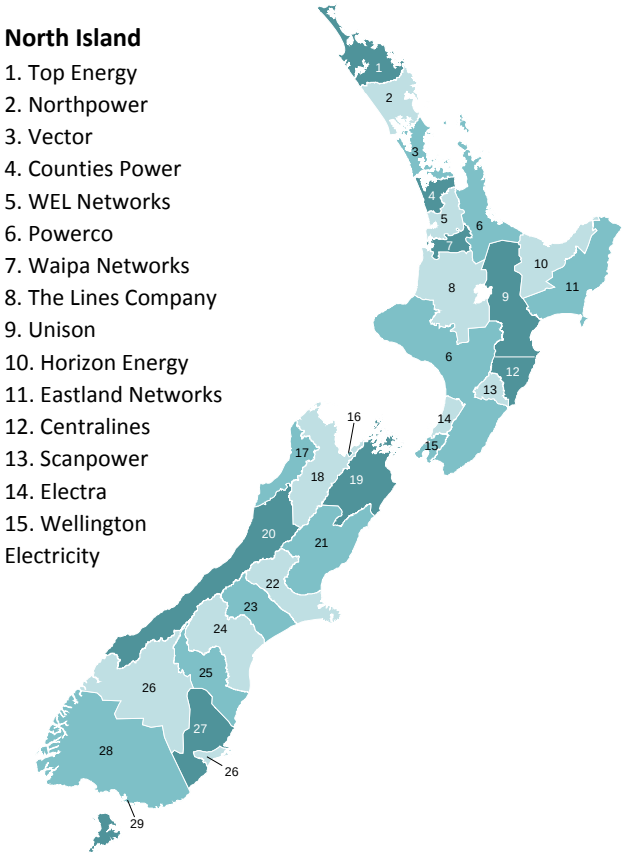
Purpose of paper

1. This paper provides our initial observations on the expenditure forecasts disclosed by 29 electricity distributors in March 2013. You are invited to provide your views in writing by **23 December 2013**. A workshop with Commission staff is scheduled for **12 December 2013**.

Summary and analysis of information disclosed in March 2013

2. Under Part 4 of the Commerce Act, the 29 electricity distributors shown in Figure 1 are subject to information disclosure regulation. Part 4 provides for regulation in markets in which there is little or no competition, and there is little or no likelihood of a substantial increase in competition.

Figure 1: Location of 29 electricity distributors



North Island
1. Top Energy
2. Northpower
3. Vector
4. Counties Power
5. WEL Networks
6. Powerco
7. Waipa Networks
8. The Lines Company
9. Unison
10. Horizon Energy
11. Eastland Networks
12. Centralines
13. Scanpower
14. Electra
15. Wellington Electricity

South Island
16. Nelson Electricity
17. Buller Electricity
18. Network Tasman
19. Marlborough Lines
20. Westpower
21. Mainpower
22. Orion New Zealand
23. Electricity Ashburton
24. Alpine Energy
25. Network Waitaki
26. Aurora Energy
27. OtagoNet
28. The Power Company
29. Electricity Invercargill

3. In each of these markets, information disclosure regulation helps people assess whether the purpose of Part 4 is being met. In broad terms, the 'Part 4 Purpose' is to promote the long-term benefit of consumers, by promoting outcomes that are consistent with those produced in competitive markets.[8]

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[8] The relevant outcomes are those reflected in the regulatory objectives in (a)-(d) of the Part 4 purpose statement. These objectives are that each regulated supplier: (a) has incentives to innovate and to invest,

4. Last year, in October 2012, we revised the disclosure requirements so that a more complete suite of information could be taken into account by people interested in assessing whether the Part 4 Purpose is being met. The first disclosures under the new requirements were due in March 2013.

Our summary and analysis role

5. Under information disclosure regulation, we are required to publish summary and analysis of disclosed information. The purpose of summary and analysis is to promote a greater understanding of the performance of each distributor, their relative performance, and the changes in performance over time.[9]

6. As we signalled in September 2013, we are currently seeking to refine our approaches for analysing the information contained in each distributor's 'Asset Management Plan'. The Asset Management Plan is the principal document that drives a distributor's asset management decisions.

7. Analysing asset management information is one part of understanding whether the Part 4 Purpose is being met. For example, one question the information helps to answer is whether distributors are operating and investing in their assets efficiently. Further explanation was provided when we set the requirements.[10]

8. However, we recognise that different stakeholders have different needs, and future analysis may focus on different information. We invite you to provide views on the usefulness of the types of analysis discussed in this paper, as well as the analysis that you would find most useful as part of our summary and analysis.

Approaches for analysing asset management information

9. In the past, our reviews of Asset Management Plans have essentially taken a compliance approach. In particular, we have asked an external consultancy to review each distributor's Asset Management Plan for compliance with the requirements. The most recent review covered the planning period April 2011 to March 2021.[11]

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including in replacement, upgraded, and new assets; (b) has incentives to improve efficiency and provide services at a quality that reflects consumer demands; (c) shares with consumers the benefits of efficiency gains in the supply of the regulated services, including through lower prices; and (d) is limited in their ability to extract excessive profits. Refer: s 52A(1) of the Act.

9 In addition, like other interested persons, we are able to monitor and analyse all information disclosed by distributors.

10 Refer: Commerce Commission, *Information disclosure for electricity distribution businesses and gas pipeline businesses: Final reasons paper*, 1 October 2012.

11 Refer: Parsons Brinkerhoff New Zealand, 2011 Asset Management Plan Reviews, 26 August 2011, which is available on the Commission's website at: www.comcom.govt.nz/review-of-asset-management-plans/.

10. However, in the context of resetting default price-quality paths, we have also developed 'top down' models of operating expenditure, which we have compared to the forecasts disclosed by 16 distributors.[12] By definition, these 'top down' models do not involve detailed 'bottom up' reviews of individual projects or programmes.

11. Other analytical approaches may potentially be suitable in future. Amongst other things, each distributor must describe the approach to risk management, consumer engagement, and the basis for making decisions on planned investments. One option is therefore to review the processes and policies described by distributors.

Initial observations informed by existing analytical techniques

12. We are interested in improving and extending our existing top down models. These models have the benefit of being relatively low cost, because they rely on readily available information. In addition, all assumptions and inputs are transparently reported.

13. In this paper, we start by setting out our initial observations on the materiality of different expenditure categories. These observations identify the categories of expenditure that we consider are the most important for us to focus on at this time. We invite you to provide your views on what areas of expenditure summary and analysis should focus on.

14. To help facilitate discussion, we then explain what we observe to be the three main drivers of expenditure, and how each driver relates to the disclosed categories of expenditure. We also list the information that is readily available about each driver. Amongst other things, these drivers are relevant to future modelling.

15. Chapter 4 sets out the differences we observe between each distributor's forecast of operating expenditure, and our own 'top down' model.[13] To help identify issues, we explain the key parts of our approach, and the options available for developing similar approaches for additional categories of expenditure.[14]

16. In Chapter 5, we set out our initial observations on the input price assumptions that are implicit in each distributor's forecast of expenditure. In particular, we compare the assumptions made by different distributors to forecasts by an independent economic forecaster.

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12 Refer, for example: Commerce Commission, *Resetting the 2010 15 Default Price-Quality Paths for 16 Electricity Distributors*, 30 November 2012, Attachment H.

13 Where differences are observed between modelled forecasts of operating expenditure and a distributor's forecast, the differences may have arisen due to drivers not captured within the model. We have not considered the specific detail in the Asset Management Plans as our primary focus is to outline how the model works and the use that might be made of it in a summary and analysis context.

14 Attachment A provides some preliminary analysis of the drivers of two of the most material categories of capital expenditure: 'asset replacement and renewal' and 'system growth';

17. The attachments to this paper provide some additional initial observations on particular areas of distributor performance. Attachment B discusses expected changes in the level of quality provided to consumers by each distributor, and attachment C provides initial observations of information disclosed in relation to energy efficiency, demand side management and reductions in losses.

Responding to this paper

18. Chapter 6 of this paper provides details about how you can provide your view on this paper. Amongst other things, we set out the address for written submissions, and the arrangements for the workshop on 12 December 2013. The purpose of the workshop is to allow you to discuss the contents of this paper with Commission staff.

19. By providing your views on this paper, you will help inform:

    19.1 an updated piece of analysis that we intend to publish next year on the same subject;[15] and

    19.2 future analysis of information disclosed by distributors in their Asset Management Plan, or other annual disclosures.

20. In addition, your views on this paper may help identify analytical improvements that could be relevant to the next reset of default price-quality paths. However, parties will have a separate opportunity to provide comments on our models at the draft decision stage in that process.

21. We also note that we have generally relied on the information as it was disclosed to us. In a limited number of cases, we have made changes where errors appeared obvious, eg, confusion of real and nominal forecasts. We welcome any feedback on the changes that we have made to the information.

Relationship with working groups established by the Electricity Networks Association

22. We also hope that this paper may contain some observations on expenditure forecasts that are relevant to the working group established by the Electricity Networks Association on forecasting approaches for default price-quality paths. Some observations may also be relevant to:

    22.1 the working group for quality of service; and

    22.2 the working group for energy efficiency, demand side management, and the reduction of losses.

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[15] For example, the analysis in this paper relies on the information disclosed by distributors in March 2013. At a minimum, we anticipate updating our initial observations to incorporate the information that was required in August 2013, including analysis of the difference between estimated and actual expenditure for 2013. The information required in August 2013 has only recently been disclosed by all distributors.

23. Nevertheless, Commission staff attend these working groups but as observers only. Any comment made by Commission staff is not a Commission view or opinion. Nothing that Commission staff say or do can bind Commissioners, who must be able to come to their own views on all matters.

2. Materiality of expenditure categories

Purpose of chapter

24. This chapter sets out our initial observations on the categories of expenditure that are most material in the forecasts:

    24.1 For the industry as a whole;[16] and

    24.2 For individual distributors.

25. This information is intended to highlight what areas of expenditure could be of particular interest when explaining the variation across distributors.

Breakdown of forecasts for industry as a whole

26. In this section, we observe what the most material categories of expenditure are for the industry as a whole. We have identified the categories that are most material in both absolute terms and relative to historic levels. In Chapter 3, we explain why each category of expenditure would be expected to change over time.

Two main categories—Capital and operating expenditure

27. Each distributor incurs two main types of expenditure when running and maintaining their network. The two categories are:

    27.1 Capital expenditure, which generally comprises investments in assets that are used to supply regulated services; and

    27.2 Operating expenditure, which generally comprises spending on operating the system, such as maintenance, vegetation management and business support.

28. Figure 2 shows that the forecast growth in total expenditure is largely driven by changes in capital expenditure.[17] The estimated increase in capital expenditure from 2012 to 2013 alone is significant (27% or $137m in 2013 prices).

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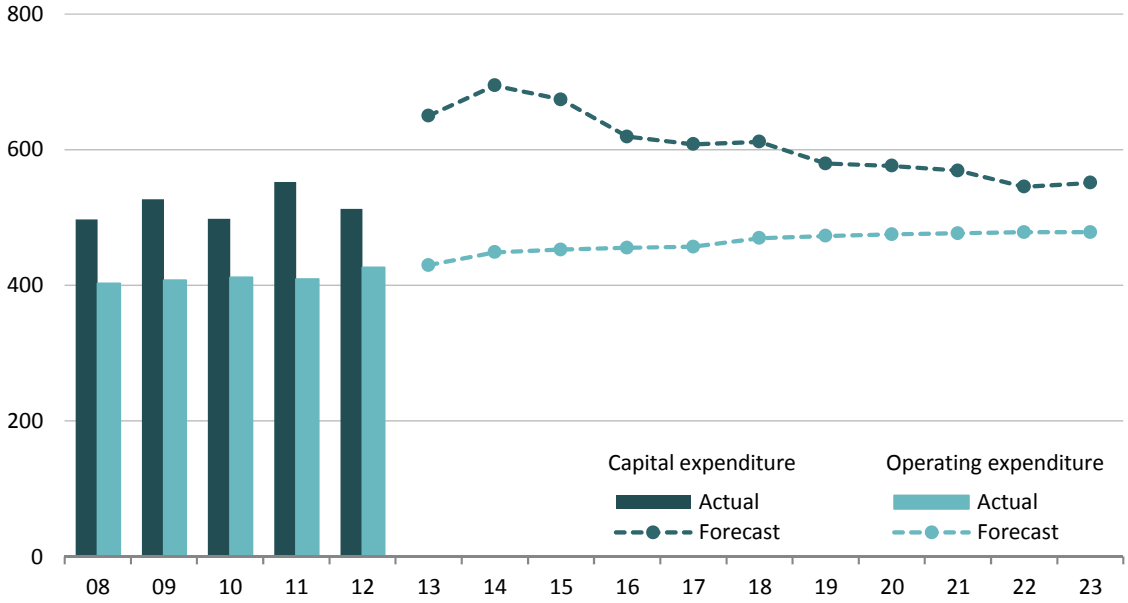
[16] Throughout this paper, the graphs and analysis for the industry as a whole exclude data relating to Orion NZ. This data has been excluded due to the significant increases in expenditure planned by Orion in response to the Canterbury earthquakes, which may distort the industry level analysis.

[17] Actual expenditure was disclosed under the requirements prior to revision in 2012, whereas forecast expenditure is based on the revised requirements. Although they are different disclosure requirements, we expect the categories to be broadly comparable. Commerce Commission, *Electricity Distribution Information Disclosure Determination*, 1 October 2012.

Figure 2: Aggregate forecast of annual operating and capital expenditure ($m, 2013 prices)



29. Our understanding is that operating expenditure has a more stable profile than capital expenditure because the activities associated with operating expenditure are more regular. For example, on-going operational maintenance can be smoothed over a number of years.

Breakdown of forecast operating expenditure at industry-level

30. For the industry overall (excluding Orion), we observe that average annual operating expenditure is forecast to be approximately 9% higher in real terms in 2014-18 relative to 2010-13 (equivalent to an average increase of $37.6m each year).[18] However, some categories are forecast to increase more than others.

31. At a high-level, we can distinguish between:

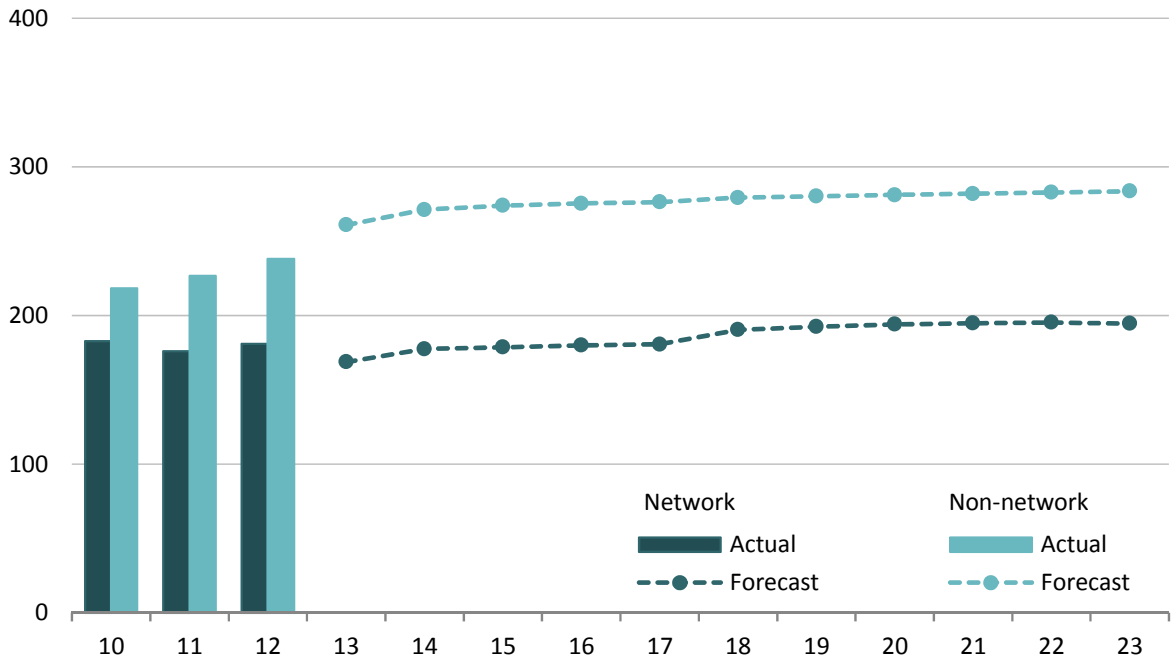
    31.1 Network expenditure, which reflects activity on the physical network (for example, expenditure on maintaining the network) and

    31.2 Non-network expenditure, which includes system operations, network support and business support activities (such as general management).

[18] For the purposes of this analysis, the forecasts of 2013 expenditure provided in the March disclosures have been treated as actual expenditure. We consider this is reasonable as this forecast will incorporate actual data that occurred during 2013 prior to the disclosure, and will likely included budgeted expenditure for the remaining year.

32. Figure 3 shows non-network accounts for approximately 60% of total operating expenditure, and network accounts for approximately 40%.

Figure 3: Aggregate forecast of annual network and non-network operating expenditure ($m, 2013 prices)

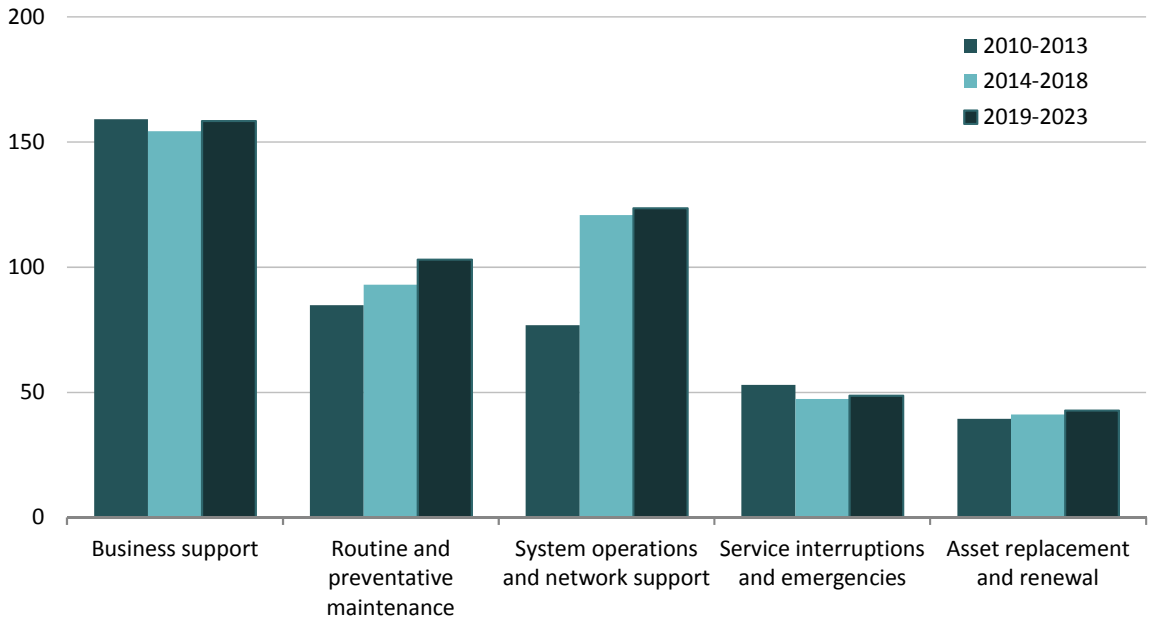


33. Breaking down operating expenditure further, we observe that the largest single category is 'business support', which includes expenditure on activities such as management and human resources. The other categories are, 'system operations and network support', 'routine and preventative maintenance', 'service interruptions and emergencies', and 'asset replacement and renewal'.[19]

34. Figure 4 shows the breakdown by category for the industry as a whole.

[19] For definitions of expenditure categories see: Commerce Commission, *Electricity Distribution Information Disclosure Determination*, 1 October 2012. Notably, under GAAP, some components of asset renewals may be treated as operational expenditure, which explains why 'asset replacement and renewal' appears as both a category of operating and capital expenditure and potentially why this is reported as a relatively small category.

Figure 4: Industry-level breakdown of annual average operating expenditure ($m, 2013 prices)



35. At the industry-level, 'system operations and network support' is forecast to increase the most. The increase in average annual expenditure on this category, from 2010-13 to 2014-19, is 57% (or $43.9m in 2013 prices). All other categories are generally expected to remain relatively stable over time.[20]

Detailed breakdown of capital expenditure at industry-level

36. For capital expenditure, we observe the forecast increase for the industry as a whole is 16% in 2013 prices from 2008-13 to 2014-19.[21] This increase is equivalent to $88.1m of average annual capital expenditure for 2008-13. As we observed with operating expenditure, however, the size of the increase varies across categories.[22]

[20] Please note that vegetation management is included in the category 'routine and preventative maintenance', in order to make the historic and recent disclosures comparable.

[21] Prior to 2010, only the network/non-network breakdown was available for capital expenditure but not for operating expenditure.

[22] The relative level of capital expenditure relative to operating expenditure capital intensity varies across distributors. The 3 most capital intensive distributors are: WEL Networks (70% of historical expenditure goes on capital investments), Electricity Ashburton (71% of historical expenditure goes on capital investments); Vector (61% of historical expenditure goes on capital investments).

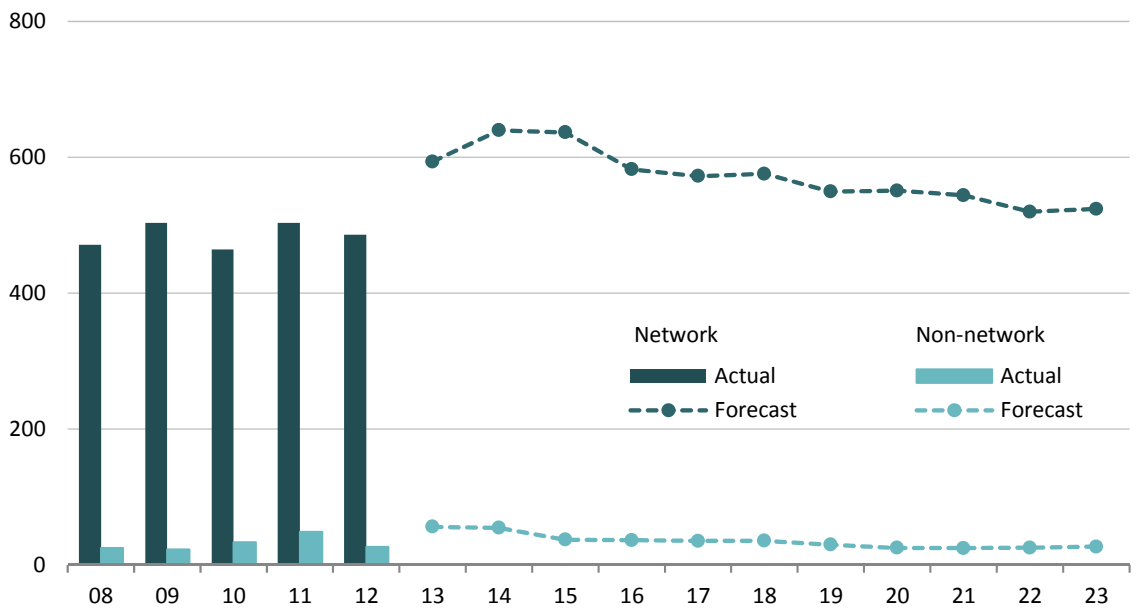
37. At a high-level, capital expenditure can also be broken down into:

    37.1 Network investments, which is expenditure on assets that form part of the physical network; and

    37.2 Non-network investments, which is spending on assets that are used to support the distribution of electricity, but not as part of the physical network.

38. For the industry a whole, network investments comprise the majority of total capital expenditure (around 90%), but the forecast trend is similar for both categories. When expressed in 2013 prices, both categories are forecast to increase from 2012 through to 2014, before tapering off for the remaining years.

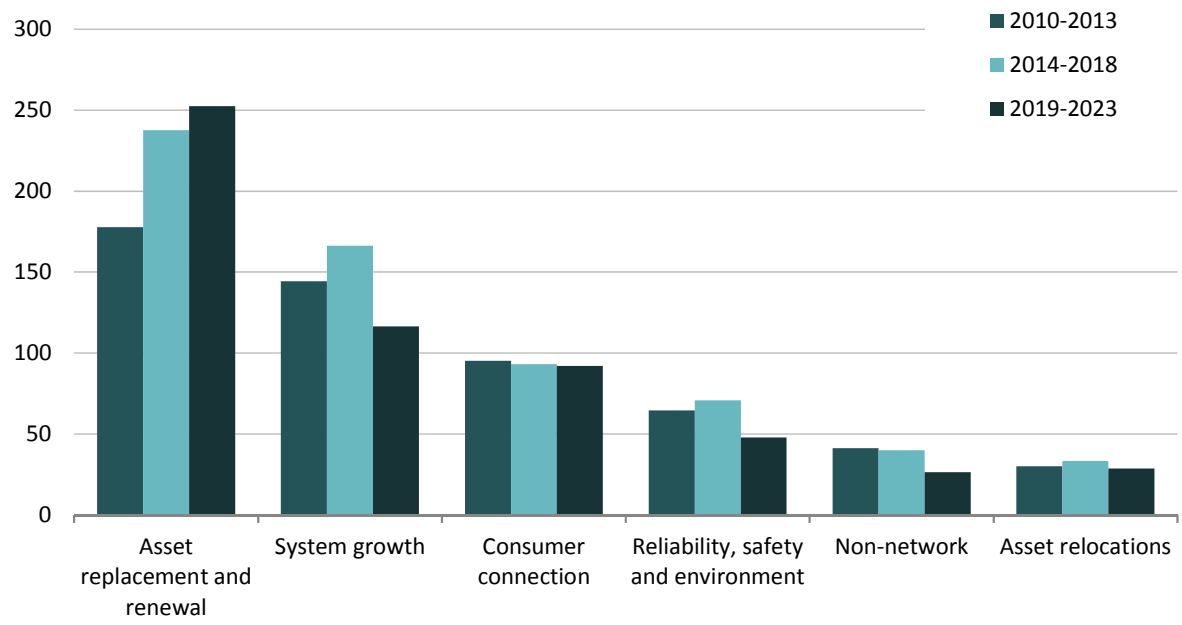
Figure 5: Aggregate forecast of annual network and non-network capital expenditure ($m, 2013 prices)



39. At the industry-level, we observe the largest individual category of capital expenditure is 'asset replacement and renewal', which relates to expenditure on replacing or renewing assets as a result of physical deterioration. Figure 6 shows a breakdown in average annual expenditure on each category at the industry-level.[23]

[23] For definitions of expenditure categories see: Commerce Commission, *Electricity Distribution Information Disclosure Determination*, 1 October 2012.

Figure 6: Industry-level breakdown of annual average capital expenditure ($m, 2013 prices)



40. Figure 6 demonstrates that 'asset replacement and renewal' is also forecast to have the most material impact on capital expenditure for the industry as a whole. The forecast increase for this category (excluding Orion NZ) is 34% in 2013 prices for 2014-18 relative to 2010-13 (equivalent to a $60m increase).

Breakdown of forecasts for individual distributors

41. In this section, we observe what the most material categories of expenditure are for individual distributors. Similar to the previous section, we have identified the categories of expenditure that are most material in absolute terms and relative to historic levels. The numerical analysis can be found in attachment D.

Breakdown of operating expenditure

42. Based on our analysis in attachment D, we observe that the largest category of operating expenditure for 21 distributors in 2010-13 was the same as it was for the industry as a whole, ie, 'business support'. However, for five distributors, the largest category was 'system operations and network support'.

43. In total, 22 distributors are forecasting an overall increase in the average amount of operating expenditure from 2010-13 to 2014-19. Of these, 15 distributors are forecasting an increase that is more than 10%, on average, each year. These changes are calculated in 2013 prices, ie, adjusted for inflation.

44. Consistent with what we observe at the industry-level:

    44.1 21 distributors are forecasting 'system operations and network support' to increase in real terms from 2010-13 to 2014-19; and

    44.2 15 distributors expecting this category to increase more in dollar terms than any other category.

45. However, although we observe a slight decline at the industry-level in expenditure on 'business support', 17 distributors are forecasting an increase in this category. Moreover, five distributors are expecting this category to increase more in dollar terms than any other category from 2010-13 to 2014-18.

46. We also observe significant changes in other categories of operating expenditure. In particular:

    46.1 16 distributors are forecasting an increase in 'routine and preventative maintenance', with six distributors expecting this category to increase more in dollar terms than any other category; and

    46.2 17 distributors are forecasting an increase in operating expenditure on 'asset replacement and renewal', with two distributors expecting this category to increase more in dollar terms than any other category.

47. In summary, 'business support' is the largest category of operating expenditure for most distributors historically, and around half the industry forecast increases in this category that are larger in dollar terms than for any other category. However, the largest dollar changes for some distributors are forecast for 'system operations and network support', 'routine and preventative maintenance', or 'asset replacement and renewal'.

Detailed breakdown of capital expenditure

48. Historically, the largest category of capital expenditure for 18 distributors has been 'asset replacement and renewal', for seven distributors it is 'system growth', and for three distributors it is 'reliability, safety and environment'. 'Consumer connection' was the largest category for only one distributor.

49. Notably, 22 distributors are forecasting an overall increase in capital expenditure. Of these, 15 distributors are forecasting an increase that is equivalent to more than 20%, on average, each year. However, seven distributors are forecasting an overall decrease in capital expenditure.

50. Consistent with what we observe at the industry-level:

    50.1 24 distributors forecast an increase in expenditure on 'asset replacement and renewal'; and

    50.2 14 distributors expect this category to increase more in dollar terms than any other category.

51. In addition, we observe that three categories of capital expenditure are forecast to increase more for certain distributors:[24]

    51.1 15 distributors forecast an increase in expenditure on 'system growth', with five distributors expecting this category to increase more in dollar terms than any other category;

    51.2 16 distributors forecast an increase in 'reliability, safety, and environment', with five distributors expecting this category to increase more in dollar terms than any other category; and

    51.3 13 distributors forecast an increase in 'non-network' capital expenditure, with three distributors expecting this category to increase more in dollar terms than any other category.

52. In summary, 'asset replacement and renewal' is generally the largest category of capital expenditure for most distributors historically, and around half the industry forecast increases in this category that are larger in dollar terms than for any other category. We also observe that the most material changes for some distributors are for 'system growth', 'reliability, safety, and environment', or 'non-network'.

[24] One distributor, Westpower, is forecasting decreases in capital investments across all categories of capital expenditure.

3. Drivers of each expenditure category

Purpose of chapter

53. To help explain how the information disclosed can assist in understanding planned expenditure, this chapter discusses:

    53.1 The main drivers of each expenditure category;

    53.2 The measures of these drivers available in information disclosure.

54. The data disclosed on these measures will allow an assessment of the expenditure forecasts provided by distributors.[25] We invite views on whether these drivers reflect the majority of distributor's decisions to spend money.

Three main drivers of expenditure

55. We have identified three main high-level drivers of expenditure which, in our view, help to explain the majority of distributor's decisions to spend money.[26] The three drivers are as follows.

    55.1 Ownership – Owning assets creates on-going expenditure obligations that can be managed but not avoided, such as the costs of routine maintenance, vegetation management, and compliance with any laws and regulations.

    55.2 Health – Expenditure is required to ensure assets remain in sufficient health to provide a particular quality of service, either through maintenance of old assets, or replacement with new.

    55.3 Capacity – Expenditure may be required to keep pace with changes in the required capacity on the network as a whole, or at individual points, depending on the current and expected utilisation of assets.

56. We have deliberately tried to identify drivers at a high-level to ensure they capture the majority of all expenditure decisions. We consider these drivers capture, at the highest level, the multiple drivers and considerations behind expenditure decisions. Furthermore, as explained in later sections, greater precision may be possible for particular expenditure categories.

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[25] Attachment A provides preliminary analysis of two areas of planned expenditure using such measures.

[26] Our work has been informed by previous submissions and feedback from stakeholders. As such, we consider our identification and description of these drivers is largely consistent with the drivers identified by distributors during previous consultations. This includes comments from stakeholders that participated in the technical working groups for the information disclosure requirements, and submissions in response to the paper: Commerce Commission, *Information Disclosure: Approaches for Understanding EDB and GPB Cost Efficiency - Technical Paper for Consultation*, 7 October 2011.

57. We invite you to provide your views on the three high-level drivers we have identified. We are particularly interested in any examples of expenditure decisions that you think cannot be explained at a high-level by one or more of the three drivers that we have identified.

Other factors affect the specific level of expenditure

58. We recognise that a number of other factors will also affect the specific level of expenditure required by each distributor. These factors are important to consider when assessing expenditure forecasts. This is because they affect the amount a distributor spends on a particular activity:

    58.1 Over time; and

    58.2 Relative to other distributors.

59. Over time, both internal and external factors will affect the amount of expenditure a distributor can expect to spend. For example:

    59.1 Changes in the distributor's target level of quality, or appetite for risk, may lead to a step change in the amount of expenditure driven by asset health-related activities;

    59.2 Changes in laws and regulations will lead to a step change in the amount of expenditure driven by asset ownership;

    59.3 Changes in input prices, or the distributor's efficiency, would be expected to affect the amount of money spent by a distributor on all activities over time.

60. Relative to its peers, the amount a distributor requires for a particular activity is more a function of the network's characteristics. In other words, the driver of the expenditure may be the same in both cases, but the impact on the distributor is different. The most commonly cited network characteristics include:

    60.1 Network design or topology – the type and configuration of asset used to supply consumers is impacted by historic design decisions, eg, voltage levels;

    60.2 Network topography – the terrain of the network can affect the cost of accessing assets; and

    60.3 Composition of consumer connections – different types of consumers have different needs, which may affect the cost of serving these consumers.[27]

[27] For example, a network with a relatively high proportion of agricultural consumers may have incur relatively higher costs in order to provide services that reflect these consumers demands.

Linking the underlying drivers to expenditure categories

61. Table 1 provides our view on which of the three drivers influence decisions on particular categories of capital and operating expenditure. We invite you to provide your views on our proposed classification.

Table 1: Proposed matching of drivers to expenditure categories

	Ownership	Health	Capacity
Capital expenditure			
Asset replacement and renewal		•	
System growth			•
Consumer connection			•
Reliability, safety and environment	•	•	•
Non-network assets	•		
Asset relocations	•		
Operating expenditure			
Business support	•		
Routine and corrective maintenance and inspection	•	•	
System operations and network support	•	•	•
Service interruptions and emergencies	•	•	
Asset replacement and renewal		•	
Vegetation management	•		

62. Table 1 reflects our view that some categories primarily have one driver, whereas others may have multiple drivers.[28] Our categorisation generally reflects the distributor's own assumption, which is implied by their allocation of expenditure. In practice, we recognise that specific projects may have multiple drivers, eg, renewal of an old and heavily loaded substation will have both capacity and health drivers.

[28] For example, system operations and network support is a result of the distributor managing its network in response to different types of activity on the network. This includes work undertaken to address asset health or capacity constraints, as well as managing assets more generally. As such, we consider it may be affected by all three drivers.

Identifying information about drivers

63. To assess whether the proposed level of expenditure is appropriate, we must first find some measures of the underlying drivers. A good measure is one that will help explain a significant proportion of the spending. However, the measures are likely to be imperfect and it may make sense to consider a suite of them together.

64. As a starting point, we have tried to identify the most appropriate information that is available to form a view on the expenditure implied by the corresponding driver(s). The sources of information that we have identified are either measures of the underlying driver, or the best available proxies.

65. In the sections that follow, we have identified whether the information is available from:

    65.1 March disclosures;

    65.2 August disclosures; or

    65.3 Alternative sources (where appropriate).

66. Each measure is likely to be important in both absolute and incremental terms. For example, an examination of expenditure could focus on whether the absolute level of expenditure is consistent with the total circuit length, or it could focus on how much expenditure had increased compared to a previous period compared to the corresponding increase in circuit length.

67. We designed the disclosure requirements to help capture the measures that would help understand the asset management decisions made by distributors. However, we welcome your feedback on whether you consider any measures are missing. In Chapter 4, we propose top down models that could use the data to inform an assessment of a distributor's forecast, alongside the narrative included in an Asset Management Plan.

Ownership driver—Measures and proxies

68. Table 1 reflects our view that some categories of expenditure are primarily driven by asset ownership, such as expenditure on business support. The amount of money a distributor spends would be expected to be related in some way to its asset base. Some examples include:

    68.1 Expenditure on routine maintenance and regular servicing are a function of owning a network;

    68.2 Expenditure on random interruptions and emergencies, caused by hazards such as storms, would be an expected cost of owning a network; and

    68.3 Expenditure on vegetation management is determined by the number of assets that are exposed to vegetation.

69. Practically, we are unable to assess the extent of asset ownership simply by summing together all the assets in the asset base. This is because the units of measurement differ depending on the asset type. For example, network length is measured in kilometres, but transformer capacity is measured in volt-amperes.

70. The measures that are most relevant for asset ownership are likely to be those that indicate the size and scale of the network. These measures should give an indication of the level of expenditure that is required due to the very existence of assets.[29] Broadly speaking, the larger the size of the network, the greater the amount of expenditure expected under a related category.

71. There are a number of ways by which the extent of asset ownership can be assessed. For example, size can be measured using monetary values associated with the size of the network, such as the value of the Regulatory Asset Base (RAB), or through non-monetary or physical values, such as the total energy delivered, or total line length.

[29] We are purely focused here on how much should be spent on assets due to their existence. We are not judging whether they should have been built in the first place.

Information available in March 2013 and August 2013 disclosures

72. There are three potential measures of asset ownership drivers available in the March disclosures:

    72.1 'Total energy delivered in 2013' (Schedule 12(c));

    72.2 'Maximum coincident system demand in 2013' (Schedule 12(c)); and

    72.3 'Distribution transformer capacity (distributor owned)' (Schedule 12(b)).

73. A further four potential measures are available in the August disclosures:

    73.1 'Number of assets (by asset category) (Schedule 9(a))

    73.2 'Total circuit length' (Schedule 9(c));

    73.3 'Total opening RAB value' (Schedule 4); and

    73.4 'Number of connections in disclosure year' (Schedule 8).

74. All of these measures provide distinct ways to assess the ownership of assets. The strength of the relationship between variation in each measure and subsequent change in expenditure will differ across the alternative measures. More detailed information on the strength of the relationship would need to be determined empirically from the data.

Alternative sources of information about the asset ownership driver

75. Looking outside the disclosed information, other the ways in which we could assess asset ownership include:

    75.1 Modern Equivalent Asset Value (MEAV);[30] and

    75.2 Non-network proxies, like regional Gross Domestic Product (GDP) or regional population.

76. Non-network proxies could be useful as they will often be highly correlated with some of the measures listed previously. For example, population will be highly correlated with the number of connections, which in turn can be used as a measure for asset ownership. Alternatively, non-network data can be utilised as either a cross-check on the disclosed data.

[30] The Modern Equivalent Asset Value could be calculated by multiplying the number of each type of asset by an appropriately defined unit costs. For example, the unit costs could be defined using the Optimised Deprival Value handbook.

Health driver—Measures and proxies

77. Asset health can be thought of in terms of the condition of the assets in the network. The category of expenditure that is most obviously driven by asset health is arguably 'asset replacement and renewal', which relates to expenditure to maintain the network asset integrity.

78. Therefore, the most relevant measures of asset health will be those that provide an indication of the condition of the network, including age, how well it has been maintained, and any unexpected events that have caused significant damage. Relevant measures may also include the outcomes of asset health, including the frequency of interruptions to the network.

79. It is also important to take into account the internal and external operating environment when evaluating expenditure driven by asset health. For example, external requirements for increased safety are likely to require increased expenditure. Alternatively, a change of internal policy to increase the average age of the assets in the network would result in lower expenditure.

Information disclosed in March 2013 and August 2013

80. We have collected three potential measures for asset health drivers in the March disclosures:

    80.1 'Asset condition at start of planning period' (Schedule 12(a));

    80.2 'Percentage of assets forecast to be replaced in the next 5 years' (Schedule 12(a)); and

    80.3 'Forecast System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) by class B and C' (Schedule 12(d)).

81. A further two potential measures are available in the August disclosures:

    81.1 'Asset Age profile' (Schedule 9(b)); and

    81.2 'Actual 2013 values for SAIDI and SAIFI by class B and C' (Schedule (10)).

82. As with asset ownership, further empirical evaluation of the relationship between measures of asset health and expenditure would appear to be required. Similarly the robustness of self-determined data needs to be evaluated in order to understand the most appropriate proxies.

Alternative sources of information about the asset health driver

83. We are not aware of any alternative sources of information about asset health outside of the information disclosed. However, we welcome examples of any potential external sources in submissions.

Capacity driver—Measures and proxies

84. Expenditure on capacity is related to the changing requirements of consumers using the network. In practice this will generally mean that the distributor must ensure sufficient capacity is built to meet increasing numbers of connections and demand for energy.

85. Categories of expenditure that appear to be primarily capacity-driven include 'system growth', which is likely to be in response to expected increases in demand. The key driver of expenditure in this area is likely to be ensuring there is sufficient capacity to ensure that current security and quality standards are maintained.

86. In addition, expenditure on 'consumer connections' may be a result of a new customer connection point, or alterations to an existing connection point. The key factor for this expenditure is likely to be ensuring there is sufficient capacity to meet the new demands of an additional or existing consumer.

87. Some of the measures of demand that represent capacity growth will be similar to the measures of asset ownership; however, in the case of capacity growth, the expenditure generally reflects changes in demand relative to existing capacity. For asset ownership-driven expenditure, it is the absolute level that matters most.

Information disclosed in March 2013 and August 2013

88. There are five potential measures of the capacity driver that are available in the March disclosures:

    88.1 'Number of forecast consumer connections' (Schedule 12(c));

    88.2 'Forecast Total energy delivered to ICPs' (Schedule 12(c));

    88.3 'Forecast maximum coincident system demand' (Schedule 12(c));

    88.4 'Current utilisation of installed firm capacity (by zone substation)' (Schedule 12(b)); and

    88.5 'Expected utilisation of installed firm capacity in five years (by zone substation)' (Schedule 12(a)).

89. We welcome examples of measures in the August 2013 disclosures that may provide an appropriate proxy for the capacity driver. We consider such measures are largely captured by information provided in the March disclosures.

90. Further analysis of the information disclosure data to understand the most significant relationships between measures of network capacity growth and expenditure will be required to determine the most appropriate available measures of the underlying capacity drivers.

Alternative sources of information about capacity driver

91. Looking beyond the disclosed information, the ways in which we could assess the capacity driver include:

    91.1 Independent forecasts of demand growth; and

    91.2 Related non-network metrics.

92. If available, independent growth forecasts that cover the growth of volume demand, peak demand, or connections would be useful; for example, to ensure the robustness of the forecasts disclosed by distributors.

93. Growth forecasts of non-network measures like GDP or population would also be relevant as a potential proxy for the capacity driver. These measures could be used as independent proxies directly linked to capacity expenditure or as a cross-check against growth measures available in the information disclosures.

4. 'Top down' models of expenditure

Purpose of attachment

94. One way to assess an expenditure forecast is to compare it to a 'top down' model that is based on transparent assumptions. Therefore, this chapter:

    94.1 Outlines our initial observations based on an existing 'top down' model for operating expenditure; and

    94.2 Discusses potential 'top down' models for capital expenditure.

95. We welcome your views on what improvements could be made to the existing 'top down' model for operating expenditure, and what issues we should consider when developing 'top down' models for capital expenditure.

Top down model of operational expenditure

96. This section outlines a top down model for operational expenditure that we have previously developed and applied when resetting default price-quality paths. This model is likely to provide some helpful insights into distributor forecasts of expenditure.

97. This model enables comparisons of distributor forecasts for operating expenditure against modelled forecasts for operating expenditure. By using this model of operating expenditure we can make observations about whether the drivers of expenditure (that underpin the model) help explain each distributor's forecasts.

Expected trend based on three high-level factors

98. Our top down model of operating expenditure works by projecting forward an initial value on the basis of the following three factors.

    98.1 Network scale – Changes in the scale of the network affects operating expenditure because it is associated with a change in the level of service.

    98.2 Operating efficiency – Changes in operating efficiency change the amount of expenditure needed to provide a given level of service.

    98.3 Input prices – Changes in input prices affect the cost of providing a given level of service.

99. These high-level factors are used to make adjustments to the level of operating expenditure each year. The formula we used is shown in Box 1.

Box 1: Formula used to model operating expenditure

$$\text{operating expenditure}_t = \text{operating expenditure}_{t-1} \times (1 + \Delta \text{ due to network scale effects} - \Delta \text{ in operating efficiency} + \Delta \text{ in input prices})$$

100. The same formula is applied separately to network and non-network operating expenditure. At this time, the separation is limited to two categories as further disaggregated information is not currently available on a consistent basis over time, and across distributors.[31]

Distributor forecast compared to Commission model

101. Table 2 shows that the results of comparing our model with the forecasts disclosed by distributors. In general, the forecasts disclosed by distributors exceed the predictions of our model, but not by as much as a simple comparison with historical averages. For around half of distributors, the forecast is within 10% of our model.

102. Differences between our forecasts and distributor forecasts could arise for a number of reasons. For example, we have not attempted to take into account the relative efficiency of each distributor. In addition, our model extrapolates historic trends in network scale rather than relying on a forecast. A number of other improvements could potentially be made if more information was available.

103. The specific details contained in the Asset Management Plans may help understand the difference between our model and an individual distributor's forecast. Evaluating these differences may also help develop a top down model that better reflects future efficient expenditure.

104. We are interested in knowing your view on whether any industry-wide adjustments should be made to our model to capture particular types of factor. The types of cost that we are interested in would be those that:

104.1 are largely outside the control of distributors;

104.2 are significant; and

104.3 affect all distributors in the industry.

105. For example, when resetting default price-quality paths, we provided an uplift to reflect the increased insurance costs resulting from the Canterbury earthquakes and other natural disasters. Such information can be incorporated into our modelling provided sufficient verification is provided.

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[31] Over time, additional and more consistent data is likely to become available to undertake the analysis at a more disaggregated level.

Table 2: Distributor forecast of operating expenditure compared to Commission model

	Network Annual average (2014-18)				Non-network Annual average (2014-18)				Total Annual average (2014-18)		
	Distributor ($m)	Commission ($m)	**Difference (%)**		Distributor ($m)	Commission ($m)	**Difference (%)**		Distributor ($m)	Commission ($m)	**Difference (%)**
Nelson Electricity	0.7	0.5	**+48**	Mainpower NZ	10.9	6.9	**+58**	Eastland Network	8.4	5.7	**+46**
Eastland Network	3.5	2.5	**+42**	Eastland Network	4.9	3.3	**+49**	Mainpower NZ	13.9	10.4	**+34**
Electricity Ashburton	2.2	1.6	**+33**	WEL Networks	13.9	10.1	**+38**	Horizon Energy	8.6	6.7	**+27**
Wellington Electricity	13.1	10.6	**+24**	Vector Lines	71.5	54.1	**+32**	Alpine Energy	15.7	12.5	**+26**
Alpine Energy	5.2	4.2	**+24**	Horizon Energy	5.8	4.5	**+31**	WEL Networks	21.5	17.3	**+24**
Horizon Energy	2.7	2.3	**+21**	Orion NZ	34.4	26.8	**+28**	Electricity Ashburton	8.4	7.1	**+18**
Waipa Networks	2.1	1.8	**+19**	Alpine Energy	10.5	8.3	**+28**	Unison Networks	34.7	29.9	**+16**
Centralines	1.7	1.4	**+17**	Unison Networks	25.6	20.1	**+27**	Northpower	14.9	13.1	**+14**
The Power Company	7.3	6.7	**+9**	Northpower	8.7	7.0	**+24**	The Lines Company	9.9	8.7	**+13**
Aurora Energy	10.5	9.7	**+9**	OtagoNet	2.8	2.3	**+23**	Vector Lines	105.8	95.3	**+11**
Electricity Invercargill	1.5	1.4	**+8**	Scanpower	1.4	1.1	**+22**	Wellington Electricity	32.3	29.5	**+9**
Westpower	5.1	4.8	**+6**	The Lines Company	6.7	5.7	**+19**	The Power Company	12.8	11.8	**+9**
WEL Networks	7.6	7.2	**+5**	Network Tasman	5.4	4.6	**+17**	Network Tasman	9.3	8.6	**+8**
The Lines Company	3.2	3.1	**+3**	Electricity Ashburton	6.3	5.5	**+14**	Electricity Invercargill	5.1	4.8	**+7**
Northpower	6.1	6.1	**+1**	Marlborough Lines	5.9	5.3	**+11**	Orion NZ	61.8	58.3	**+6**
Powerco	31.8	31.7	**0**	Powerco	38.3	34.7	**+10**	Powerco	70.1	66.4	**+6**
Network Tasman	4.0	4.0	**–1**	The Power Company	5.4	5.1	**+7**	Westpower	8.5	8.1	**+5**
Network Waitaki	1.7	1.8	**–3**	Electricity Invercargill	3.6	3.3	**+7**	Nelson Electricity	2.1	2.1	**+5**
Counties Power	3.5	3.6	**–4**	Network Waitaki	1.9	1.8	**+7**	Waipa Networks	4.9	4.7	**+4**
Unison Networks	9.1	9.8	**–7**	Top Energy	8.1	7.7	**+5**	Scanpower	2.2	2.1	**+4**
Electra	4.7	5.2	**–9**	Counties Power	6.5	6.2	**+4**	OtagoNet	6.1	5.9	**+3**
Buller Electricity	0.9	1.0	**–9**	Westpower	3.3	3.2	**+3**	Network Waitaki	3.6	3.6	**+2**
OtagoNet	3.2	3.6	**–10**	Wellington Electricity	19.1	19.0	**+1**	Counties Power	10.0	9.9	**+1**
Orion NZ	27.5	31.5	**–13**	Waipa Networks	2.8	2.9	**–5**	Top Energy	13.5	14.6	**–8**
Mainpower NZ	3.0	3.5	**–15**	Nelson Electricity	1.5	1.6	**–8**	Marlborough Lines	12.2	13.6	**–11**
Vector Lines	34.3	41.2	**–17**	Centralines	1.3	2.0	**–33**	Centralines	3.0	3.4	**–12**
Scanpower	0.8	1.0	**–17**	Electra	2.1	4.4	**–51**	Electra	6.8	9.5	**–28**
Top Energy	5.5	6.9	**–21**	Aurora Energy	0.9	10.1	**–92**	Aurora Energy	11.4	19.8	**–42**
Marlborough Lines	6.3	8.3	**–24**	Buller Electricity	0.0	2.4	**–100**	Buller Electricity	0.9	3.4	**–73**
Industry Total (excl. Orion)	181.4	185.4	**–2**	Industry (incl. Orion)	275.2	243.1	**+13**	Industry (incl. Orion)	456.6	428.5	**+7**

Initial level of operating expenditure

106. For both network and non-network operating expenditure, the starting point for our formula is an initial amount and, for this paper, we have relied on the estimate provided by distributors for the 2013 disclosure year. An alternative option would be to use an average of a number of historical years

Change due to network scale effects

107. As discussed in Chapter 3, we consider it likely that operational expenditure is influenced by the scale of the network to a large extent. Therefore, to estimate likely changes in operational expenditure the model includes two measures for changes in the network scale:

    107.1 For network operating expenditure, average growth in network length; and

    107.2 For both network and non-network operating expenditure, average growth in the number of connections, where connection numbers are assumed to grow at the same rate as the local population.

108. These measures were identified from standard statistical tests on a number of possible explanatory measures of network scale, combined with engineering analysis, and underlying theory. We explored combinations of potential measures of scale, assessed the statistical robustness of the results, and considered the intuition of the resulting coefficients.[32]

109. For network operating expenditure, our econometric model indicates that:

    109.1 A 1% change in network length is associated with a 0.48% change in expenditure; and

    109.2 A 1% change in the number of connections is associated with a 0.47% change in expenditure.

110. For non-network operating expenditure, a 1% change in the number of connections is associated with a 0.82% change in non-network operating expenditure.

[32] Further information on the methods undertaken are available in Commerce Commission, *Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors*, 30 November 2012.

Change due to improvements in operating efficiency

111. Our forecast assumes there will be no change in the average operating efficiency of electricity distributors compared to all other sectors in the economy. This assumption is informed by previous pieces of analysis provided by Economic Insights and by Pacific Economics Group.[33]

112. We have assumed the same forecast change in operating efficiency for all distributors. This assumption may be more challenging for some distributors than it is for others. However, we have not previously made any adjustments to operating efficiency based on the relative efficiency of each distributor.[34]

Change due to input prices

113. Our forecast includes a measure of the forecast changes in input prices. Changes in input prices will affect the annual cost of providing a given level of service.

114. Operating expenditure is adjusted for forecast changes in the cost of inputs using the weighted average forecasts of the changes in the all industries labour cost index, and the all industries producer price index. The New Zealand Institute of Economic Research provided forecasts of these indices.

115. We have weighted the forecast of the labour cost index by 60% and the forecast of the producer price index by 40%. In the absence of data from New Zealand distributors, these weights are based on analysis of expenditure by their Australian counterparts.[35]

116. Chapter 5 summarises the input price assumptions used by distributors in their nominal forecasts of operating expenditure. This also includes a comparison with the input price forecasts produced by the New Zealand Institute of Economic Research.

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[33] Economic Insights, *Electricity Distribution Industry Productivity Analysis: 1996–2008, Report prepared for the Commerce Commission*, 1 September 2009, Pacific Economics Group, *Reset of Default Price Path for Electricity Distribution Businesses: Submission to the Commerce Commission,* Report prepared for the Electricity Networks Association, August 2009, Pacific Economics Group, *TFP Research for Victoria's Power Distribution Industry: 2007 Update*, Report prepared for Essential Services Commission, 2008.

[34] We do however plan to undertake further analysis to explore approaches for assessing the relative efficiency of distributors, and will engage with the industry on this in due course.

[35] Pacific Economics Group, TFP Research for Victoria's Power Distribution Industry: 2005 Update, Report prepared for Essential Services Commission, 2006. Meyrick and Associates, The Total Factor Productivity Performance of Victoria's Gas Distribution Industry, Report prepared for Envestra, Multinet and SP AusNet, Denis Lawrence, 2007.

Focus for future work

117. We invite views on a range of matters regarding our opex forecasting approach, but we note that our focus is on identifying and quantifying any factors not already captured by the current model.[36] However, we remain open to alternative approaches for forecasting operating expenditure.[37]

Building a model for capital expenditure

118. As discussed in Chapter 3, different categories of capital expenditure have different drivers. Information disclosed by distributors may allow us to measure these expenditure drivers, and therefore assist in understanding distributor forecasts of expenditure and quality.

119. We are interested in views on how we can use the data disclosed to build top down models of forecast capital expenditure. Such models could, at a high-level, predict the likely level of expenditure required on the network, or changes in expenditure relative to historic levels. These models could then be used to provide an indication of the likely efficiency and appropriateness of the distributor's forecast.

Any model will need to distinguish between the different categories

120. As shown in Chapter 3, different categories of capital expenditure are likely to have distinct sets of drivers. Therefore, it may be appropriate to build separate models for the different categories of capital expenditure:

    120.1 Consumer connection;

    120.2 System growth;

    120.3 Asset replacement and renewal;

    120.4 Asset relocations;

    120.5 Reliability, safety and environment; and

    120.6 Non-network assets.

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[36] We have included functionality to include industry-wide factors not already captured by the modelled trend.

[37] We have, however, already considered and rejected the arguments advanced in favour of some approaches, such as extrapolation of recent trends. We encourage you to consider our previous reasoning when providing your views. These reasons are outlined in Commerce Commission, *Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors*, 30 November 2012.

121. An overall assessment of capital expenditure could then be formed by combining the outputs of the distinct models. The results of the models may also indicate where more detailed analysis is required to better understand distributor performance, including information provided in each distributor's Asset Management Plan.

122. There are a number of methods by which a model could be developed for each of these expenditure categories. Two generic approaches to determine capital expenditure forecasts are considered here: a capital expenditure adjustment method and an absolute calculation. These are explained below together with high-level examples of how they could be implemented for selected expenditure categories.

Adjustment method

123. One approach would be to take historic average expenditure on the category of capital expenditure and then project this forward, adjusting for any likely changes in this expenditure as a result of likely changes in the performance of the network. This analysis would use information disclosed on the current and expected network performance, including asset age and condition and network utilisation.

124. As capital expenditure is largely irregular and 'lumpy', we consider that the historic average level of capital expenditure should be determined from a longer time period than the single year that has been used for the opex model. An appropriate baseline for capital expenditure could therefore be five years.[38] It may also be appropriate to remove the impact of atypical investments and one-off events where possible.

125. Following the determination of the historical average, changes would reflect the high-level drivers outlined in Chapter 3. Some examples of potential approaches to calculating the adjustment for selected expenditure categories are as follows.

    125.1 System growth – Forecast expenditure could be estimated by adjusting historic expenditure relative to the forecast change in peak demand. An adjustment could also be made to take into account network utilisation.

    125.2 Customer connections – Forecast expenditure could be estimated by adjusting historic expenditure by forecast changes in the level of connections.

    125.3 Asset replacement – Forecast expenditure could be estimated by adjusting historic expenditure with reference to the changing age of the network and forecast changes in the quality of service provided.

[38] Although individual capital expenditure projects are often irregular, the aggregate trend in capital expenditure is smoother than it is for individual projects. Therefore using a 5 year average may be sufficient to achieve appropriate baseline.

126. Developing such a model would require the identification of the impact of a change in the representative drivers on the relevant category of expenditure, ie, to consider whether an increase is the driver used has a one for one impact on expenditure.

Absolute calculation

127. Another option to forecast expenditure would be to estimate the absolute value of expenditure based on information on the current and expected performance of the network. This approach would have less focus on the immediately preceding period of historical capital expenditure, but would likely use historic unit cost information.

128. Below we provide examples of how an absolute calculation might work in practice for selected capital expenditure categories.

    128.1 System growth – For this category, we might calculate a Modern Equivalent Asset Value for the existing network. [39] Forecast expenditure could then be determined by the assumption that the Modern Equivalent Asset Value would increase relative to the forecast increase in peak demand.

    128.2 Consumer Connections – Forecast expenditure could be calculated by multiplying the increase in the number of consumer connections by a unit cost for connections.[40]

    128.3 Asset replacement – Forecast expenditure could be calculated in number of ways using existing information on current asset ages. Some examples could be: dividing the current Modern Equivalent Asset Value by the average depreciation rate; calculate the change in the Modern Equivalent Asset Value required to maintain average asset age; or making use of an age-based survivor model and the unit cost of replacing different asset types.

129. The absolute calculation approach may also be appropriate for non-network capital expenditure and asset relocations, which are potentially less driven by changes in network performance. For example, forecast capital expenditure on non-network activities could be calculated as a proportion of the RAB or the Modern Equivalent Asset Value.

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[39] As noted in Chapter 3, the Modern Equivalent Asset Value could be calculated by multiplying the number of each type of asset by an appropriately defined unit costs. For example, the unit costs could be defined using the Optimised Deprival Value handbook.

[40] This unit cost could be determined in a number of ways, eg, industry average, average of an industry subset or bottom up calculations.

Issues to consider when developing a model

130. There are a number of issues to consider when building a top down model for capital expenditure. Some of these include exploring:

130.1 whether separate models should be developed for distributors with similar characteristics, or whether one model for all distributors would be sufficient (however the models would use distributor-specific data);

130.2 whether the unit costs used for any model should be distributor-specific, industry-wide, or estimated based on different sub-sets of distributors with similar characteristics;

130.3 how the unit costs should take into account future likely changes in technology and efficiency;

130.4 what categories of expenditure can be assumed to be relatively constant, and how to take into account any step changes (for example, changes in legislative requirements);

130.5 how to estimate the impact of changes in the drivers of expenditure on each category of expenditure; and

130.6 To what extent should the model rely on distributor forecasts of the drivers of expenditure (for example, forecast changes in demand).

Focus for future work

131. We invite views on all aspects of how we could progress development of a capital expenditure forecasting approach. However, we are particularly interested in:

131.1 whether you agree in principle developing a capital expenditure forecasting model outlined above, to help explain variation in the amount different distributors forecast to spend relative to the past; and

131.2 your views on the modelling approaches proposed in this chapter, and the preliminary analysis outlined in attachment A.

132. Similar issues are being considered by the working group established by the Electricity Networks Association on forecasting approaches for default price-quality paths. We therefore anticipate that the output of that group may provide insights that are useful in developing a model for summary and analysis.

5. Forecast changes in input prices

Purpose of attachment

133. This chapter provides our initial observations on the input price assumptions that are implied by each distributor's forecasts.

Forecasts disclosed in current and constant prices

134. Distributors are required to disclose expenditure forecasts in both real terms (2013 prices) and nominal terms (prevailing prices). Figure 7 and Figure 8 show the difference between the forecast in real and in nominal terms.

135. As we would expect, operating expenditure is expected to increase in both real and nominal terms. However, capital expenditure is forecast to decline in real terms from the peak in 2014, relative to the comparatively flat forecast in nominal terms.

Figure 7: Operating expenditure forecast in real and nominal terms

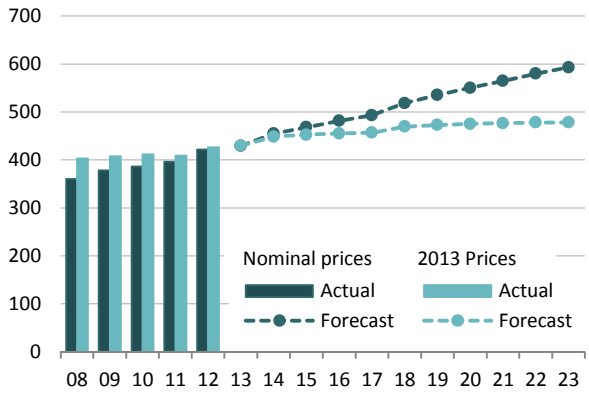
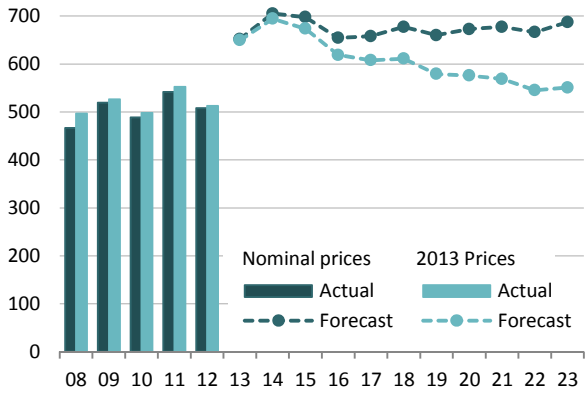


Figure 8: Capital expenditure forecast in real and nominal terms

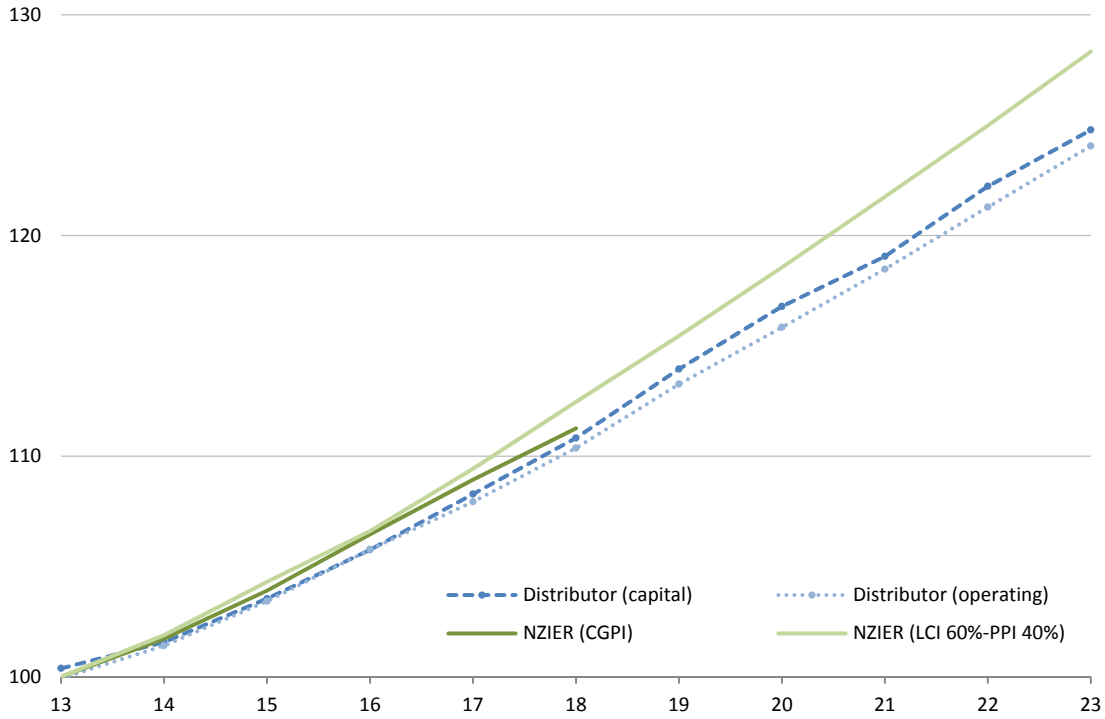


136. The difference between the expenditure forecasts in real and nominal terms is the expected change in the costs of the inputs used by distributors, ie, changes in input prices. The input prices include the cost of labour and materials.

Implied forecasts of changes in input prices

137. By comparing the distributor's forecasts in real and nominal terms, we have been able to calculate the implied forecast change in input prices. The forecast change in input prices is illustrated in Figure 9, along with external forecasts of input prices provided by New Zealand Institute of Economic Research.

Figure 9: Implied input price deflators (2013=100)



138. The capital and operating expenditure input prices disclosed by distributors are forecast to grow at broadly the same rate of around 25% from 2013 to 2023. This is equivalent to an increase in input prices of around 2% per year.

139. Also shown in Figure 9 is the forecast by the New Zealand Institute of Economic Research of the Capital Goods Price Index and, and a weighted average of the labour cost index and producer price index. As discussed in Chapter 4, the weighted average index has been used as a proxy for likely changes in the cost of inputs that affect a distributor's operational expenditure. Meanwhile, the Capital Goods Price Index may capture likely changes in the cost of inputs that affect capital expenditure.

140. Figure 9 shows that the forecast by the New Zealand Institute of Economic Research:

140.1 For operating expenditure, the weighted average index is expected to grow at a faster rate than the industry forecast;

140.2 For capital expenditure, the Capital Goods Price Index is forecast to grow at a faster rate than the industry forecast.

141. Table 3 shows that individual distributor's expectations of changes in input prices vary. For operating expenditure, expected changes in input prices range between −0.9% and 3.5% per year. For capital expenditure, expected changes input prices are range between −4.2% and 3.5% per year.

142. More information on sources and methods used to forecast input prices can be found in the Asset Management Plans and explanatory notes supporting the information disclosures.

Table 3: Distributor forecasts of changes in input prices (average percentage growth per year 2013-2018)

	Capital expenditure	Operating expenditure
Alpine Energy	1.9	1.7
Aurora Energy	0.4	-0.3
Buller Electricity	2.2	2.8
Centralines	2.0	2.0
Counties Power	1.9	1.9
Eastland Network	2.5	2.5
Electra	2.8	2.2
Electricity Ashburton	2.1	2.1
Electricity Invercargill	2.0	-0.9
Horizon Energy	1.8	1.8
Mainpower NZ	2.0	0.7
Marlborough Lines	1.8	2.6
Nelson Electricity	1.8	1.8
Network Tasman	2.0	2.0
Network Waitaki	1.7	1.6
Northpower	3.5	3.5
Orion NZ	2.5	2.9
OtagoNet	2.0	2.3
Powerco	2.2	2.2
Scanpower	-4.2	0.0
The Lines Company	2.5	2.4
The Power Company	2.6	1.9
Top Energy	2.0	2.0
Unison Networks	2.0	2.0
Vector Lines	2.1	2.1
Waipa Networks	1.2	1.6
WEL Networks	2.1	2.0
Wellington Electricity	2.3	2.3
Westpower	0.3	1.4
Industry Total (excl. Orion)	2.1	2.0

6. How you can provide your views

Purpose of chapter

143. This chapter sets out how you can respond to this paper, as well as details for the workshop on the contents of this paper.

Responding to this paper

144. As noted in the Introduction, we welcome your views on any aspect of this paper. In particular, we are keen to hear your views on how top down models could be used to understand distributor performance. This includes identifying whether the existing model for operational expenditure could be further developed to better reflect distributor's expenditure requirements, and how models could be developed for capital expenditure.

145. Submissions are due by **5pm, 23 December 2013**. We do not anticipate a need for cross-submissions on this paper.

146. We also intend to hold a workshop on **12 December 2013** to provide people with opportunities to discuss the contents of this paper with Commission staff. Further details about the workshop can be found below.

Address for responses

147. Responses to this paper should be addressed to:

> John McLaren (Chief Advisor, Regulation Branch)
> c/o regulation.branch@comcom.govt.nz

148. We prefer responses in a file format suitable for word processing, rather than the PDF file format.

Requests for confidentiality

149. We encourage full disclosure of submissions so that all information can be tested in an open transparent manner, but we offer the following guidance.[41]

149.1 If it is necessary to include confidential material in a submission, the information should be clearly marked, with reasons why that information is confidential.

149.2 Both confidential and public versions of the submission should be provided.

149.3 The responsibility for ensuring that confidential information is not included in a public version of a submission rests entirely with the party making the submission.

150. We request you provide multiple versions of your submission if it contains confidential information or if you wish for the published electronic copies to be 'locked'. This is because we intend to publish all submissions and cross-submissions on our website. Where relevant, please provide both an 'unlocked' electronic copy of your submission, and a clearly labelled 'public version'.

Arrangements and format of workshop

151. A workshop will be held at our Wellington office, and you will need to make your own arrangements to be present.

151.1 The workshop will be held at 10am-1pm, on **Thursday 12 December 2013**.

151.2 Our address is Level 6, 44 The Terrace, Wellington.

152. Places at the workshop may be limited. Please email us to confirm your attendance or intention to listen via teleconference. Emails should be sent to the same address as responses for this paper, and have "initial observations workshop" in the subject line.

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[41] You can also request that we make orders under s 100 of the Act in respect of information that should not be made public. Any request for a s 100 order must be made when the relevant information is supplied to us, and must identify the reasons why the relevant information should not be made public. We will provide further information on s 100 orders if requested by parties. A key benefit of such orders is to enable confidential information to be shared with specified parties on a restricted basis for the purpose of making submissions. Any s 100 order will apply for a limited time only as specified in the order. Once an order expires, we will follow our usual process in response to any request for information under the Official Information Act 1982.

Purpose and format of workshop

153. The workshop will give people an opportunity to discuss the contents of this paper with Commerce Commission staff. We anticipate this is likely to be of interest to stakeholders interested in understanding more about some of the observations made in this paper, and the likely types of analysis the Commission hopes to do in the future. Commissioners will not be present at the workshop.

154. The format and agenda for the workshop will be confirmed nearer the time but is likely to include presentations from Commission staff, a round table discussion on the contents of this paper, and presentations by stakeholders. The workshop will provide an opportunity for you to discuss your views. However, submissions remain the main avenue to provide views to the Commission.

155. We encourage people to contact us before the workshop if there are particular topics they wish to see discussed. You can contact us using the same email address that is provided for responding to this paper. To allow adequate preparation time, the cut-off for proposed topics for the workshop is **5pm Friday, 6 December 2013**.

Material released alongside this paper

156. We will also release the Excel database used in the production of this paper. This database contains the information disclosed by distributors in March 2013, as well as information disclosed previously. This database has been presented in a format to allow for easy use of the data. We would be happy to answer any questions you have on the database at the workshop.

Attachment A: Preliminary analysis of capital expenditure

Purpose of attachment

157. The purpose of this attachment is to provide preliminary analysis of the information disclosed in March 2013 about two of the most material categories of capital expenditure:

157.1 Asset health-driven expenditure on asset replacement; and

157.2 Capacity-driven expenditure on system growth.

158. In this analysis, we show the forecast changes in expenditure alongside the corresponding drivers.

Asset health-driven investments in replacement and renewal

159. As explained in Chapter 2, distributors are forecasting significant expenditure on asset replacement and renewal. Average annual expenditure by the industry in this area is forecast to increase in real terms by 34% for 2014-18 relative to 2010-13. Individually, 24 of the 29 distributors are forecasting an increase in expenditure on asset replacement and renewal.

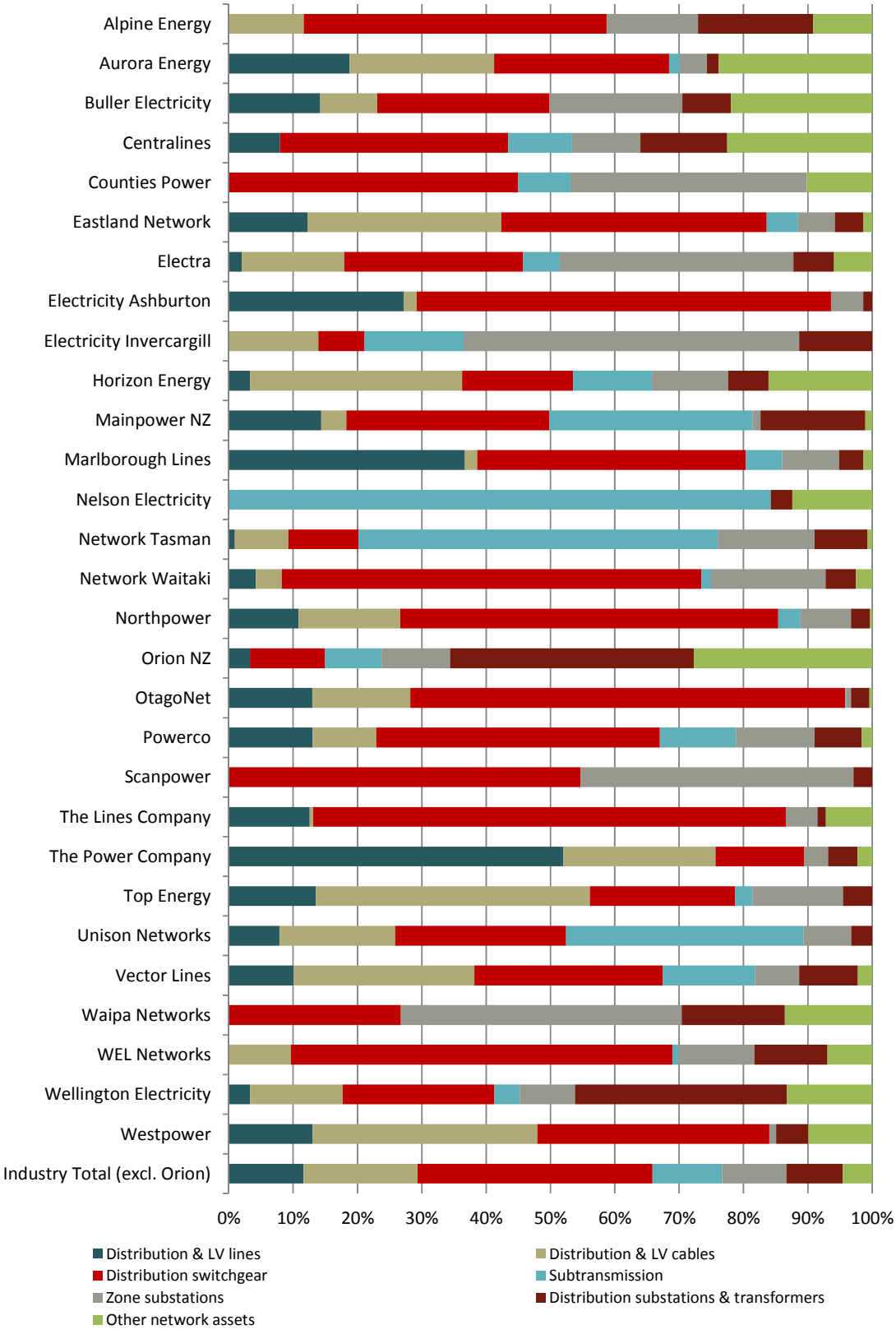
160. As shown in **Figure** 10, much of the forecast increase in expenditure on asset replacement and renewal is going on assets relating to:

160.1 Distribution and low voltage lines;

160.2 Subtransmission assets; and

160.3 Zone substations.

Figure 10: Breakdown of forecast expenditure on replacement and renewal by asset category (annual average % for 2013-18)



161. We have analysed information disclosed about asset health-driven expenditure on asset replacement and renewal for the purpose of promoting greater understanding of each distributor's forecast changes in expenditure in this areas. This analysis also helps illustrate how the information disclosed could be used in a top down model to help create greater understanding of forecast changes in each distributor's expenditure on asset replacement and renewal on these three asset groups.

162. We have explored:

    162.1 information disclosed that is intended to capture the health of these assets, ie, the proportion of these categories of assets that are classified as grade 1 or 2 and therefore needing short term intervention; and

    162.2 the proportion of assets that a distributor expects to be replaced by 2018.

163. We would expect that a distributor that is forecasting significant increases in expenditure on asset replacement and renewal is also expecting to replace a high proportion of its assets. This may also be reflected in a forecast improvement in quality. We would also expect that such a distributor has a high proportion of assets that requires short term intervention.

Replacement and renewal of distribution and low voltage lines

164. For distribution and low voltage lines, Table 4 shows that:

    164.1 18 distributors forecast an increase in expenditure;

    164.2 10 distributors forecast a decrease in expenditure;

    164.3 the proportion of assets relating to distribution and low voltage lines requiring short term intervention varies from 0% to 100%, but is generally less than 10%;

    164.4 typically, distributors are forecasting to replace less than 5% of their assets relating to distribution and low voltage lines; and

    164.5 as expected, those distributors with a small proportion of assets in grade 1 or 2 have forecast only a small proportion of their assets to be replaced.

165. Notably, not all distributors are forecasting to replace assets considered to be grade 1 or 2, which may have a detrimental impact on quality. Readers should refer to attachment B to assess whether these distributors are expecting a change in quality. However, distributors may also be planning to address these assets using operational expenditure, including additional maintenance of these assets, or through operational expenditure on asset replacement and renewal. Alternatively, the assets may not be considered to be critical.

Table 4: Asset health-driven expenditure on distribution and low voltage lines (%)

	Expenditure on distribution and low voltage lines					Low voltage overhead conductor (%)		Distribution overhead open wire conductor (%)		Concrete poles / steel structure (%)		3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers (%)		3.3/6.6/11/22kV Switches and fuses (pole mounted) (%)	
	Annual			Forecast change											
	Estimate 2013 ($m)	Average 2014–18 ($m)	% of forecast asset replacment and renewal	2013 to 2014–18 ($m)	2013 to 2014–18 (%)	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018
Alpine Energy	0.4	1.3	47	0.9	+201	7	0	0	0	7	7	0	0	0	0
Aurora Energy	3.0	2.4	27	-0.6	–20	9	0	9	0	1	0	0	0	18	0
Buller Electricity	0.3	0.2	27	-0.2	–50	9	6	10	5	2	7	0	4	10	16
Centralines	1.0	0.5	35	-0.4	–45	15	4	30	4	6	4	0	1	15	1
Counties Power	1.3	1.7	45	0.4	+34	0	5	12	1	0	1	0	0	0	5
Eastland Network	2.5	2.7	41	0.2	+8	0	0	0	1	5	6	10	13	6	8
Electra	0.9	1.6	28	0.8	+84	1	2	11	7	0	5	3	6	2	10
Electricity Ashburton	0.6	0.9	64	0.3	+50	50	25	0	0	6	5	0	0	0	0
Electricity Invercargill	0.2	0.1	7	-0.1	–42	15	5	25	5	5	5	0	0	20	10
Horizon Energy	0.0	0.7	17	0.7	n/a	0	2	0	0	1	1	0	0	0	1
Mainpower NZ	0.4	1.2	32	0.8	+185	0	10	0	10	0	1	0	10	0	6
Marlborough Lines	3.3	3.1	42	-0.2	–7	2	5	1	5	1	2	0	10	0	2
Nelson Electricity	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0	0	0	0	0
Network Tasman	0.7	0.2	11	-0.5	–72	0	2	1	1	3	2	13	29	10	10
Network Waitaki	0.6	0.8	65	0.1	+23	2	2	5	5	4	5	5	5	5	5
Northpower	4.2	5.3	59	1.1	+26	46	10	43	5	42	2	100	5	53	15
Orion NZ	2.6	3.0	12	0.3	+13	0	0	0	3	0	1	0	0	0	18
OtagoNet	0.0	4.9	68	4.9	n/a	2	3	6	18	3	5	8	54	25	10
Powerco	13.6	18.1	44	4.5	+33	1	0	1	2	1	6	1	34	0	10
Scanpower	0.0	0.3	55	0.3	n/a	33	0	33	0	0	0	0	0	52	6
The Lines Company	4.9	5.2	73	0.3	+6	0	0	0	0	5	6	1	1	0	0
The Power Company	2.8	1.1	14	-1.7	–61	5	5	5	10	5	5	3	3	7	7
Top Energy	2.8	1.5	23	-1.2	–45	2	0	5	5	7	5	5	5	29	29
Unison Networks	0.0	4.3	27	4.3	n/a	1	0	1	0	0	0	0	0	0	0
Vector Lines	0.0	16.8	29	16.8	n/a	0	0	0	0	0	6	1	10	6	10
Waipa Networks	0.3	0.2	27	-0.1	–40	2	2	5	5	4	4	15	15	5	5
WEL Networks	5.9	6.8	59	1.0	+16	0	0	0	3	2	2	0	15	7	6
Wellington Electricity	4.2	4.4	24	0.2	+5	15	1	11	1	5	5	20	20	15	10
Westpower	0.6	0.4	36	-0.2	–30	3	0	2	2	1	0	0	0	5	5

Replacement and renewal of zone substations

166. For zone substations, Table 5 shows that:

166.1 16 distributors forecast an increase in expenditure;

166.2 Nine distributors forecast a decrease in expenditure;

166.3 relative to other assets, some distributors report a high proportion of assets in zone substations are classified as grade 1 or 2; and

166.4 typically, distributors are forecasting to replace less than 10% of their zone substation assets, with many not planning any expenditure on these assets.

167. Notably, not all distributors are forecasting to replace assets considered to require short term intervention. As discussed previously, this approach may increase the number of interruptions. Readers should refer to attachment B for information about each distributor's forecasts for reliability.

Table 5: Asset health-driven expenditure on zone substations (%)

	Expenditure on zone substations					Zone Substation Transformers (%)		Switchgear - Indoor 22/33kV CB (%)		Switchgear - Outdoor 22/33kV CB (%)		Switchgear - Pole mounted 33kV Switch (%)		Switchgear - Ground mounted 33kV Switch (%)	
	Annual		% of forecast asset replacment & renewal	Forecast change											
	Estimate 2013 ($m)	Average 2014–18 ($m)		2013 to 2014–18 ($m)	2013 to 2014–18 (%)	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018
Alpine Energy	0.4	0.3	12	-0.1	+77.5	15	12	0	0	0	5	0	0	17	16
Aurora Energy	2.1	2.0	22	-0.2	+91.6	0	0	0	0	46	0	42	0	33	0
Buller Electricity	0.1	0.1	9	0.0	+57.8	40	0	0	0	0	0	0	0	0	0
Centralines	0.1	0.0	0	-0.1	−1.0	0	0	0	0	0	0	26	10	0	33
Counties Power	0.1	0.0	0	-0.1	−1.0	0	0	11	0	37	0	0	0	0	0
Eastland Network	0.2	2.0	30	1.7	+808.9	6	6	0	0	0	0	0	0	12	12
Electra	0.3	0.9	16	0.7	+346.8	0	0	0	0	8	19	0	14	10	10
Electricity Ashburton	0.0	0.0	2	0.0	n/a	0	0	0	0	0	0	0	0	0	0
Electricity Invercargill	0.0	0.3	14	0.2	+675.6	0	0	0	50	25	25	20	20	50	50
Horizon Energy	0.0	1.4	33	1.4	n/a	0	9	0	0	0	50	0	20	0	0
Mainpower NZ	0.0	0.1	4	0.1	+310.7	0	20	0	10	0	10	0	10	0	10
Marlborough Lines	0.0	0.1	2	0.1	n/a	0	0	0	0	0	0	0	0	0	0
Nelson Electricity	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0	0	0	0	0
Network Tasman	0.1	0.1	8	0.1	+193.4	0	0	0	0	0	0	0	0	11	11
Network Waitaki	0.2	0.0	4	-0.1	+27.3	0	0	0	0	0	0	0	0	0	0
Northpower	0.6	1.4	16	0.8	+231.8	33	10	64	15	68	15	18	5	54	15
Orion NZ	0.0	0.0	0	0.0	n/a	1	0	0	0	0	0	0	0	0	17
OtagoNet	0.0	1.1	15	1.1	n/a	10	7	0	0	24	14	13	7	17	14
Powerco	3.6	4.1	10	0.4	+110.1	11	9	1	2	0	2	0	27	0	4
Scanpower	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0	0	0	0	0
The Lines Company	0.1	0.0	1	-0.1	+40.7	0	0	0	0	0	0	1	1	0	0
The Power Company	2.1	1.9	24	-0.2	+90.0	8	10	0	0	5	5	2	2	7	7
Top Energy	0.0	2.9	43	2.9	n/a	6	6	0	0	44	20	37	19	8	8
Unison Networks	0.0	2.9	18	2.9	n/a	22	8	0	0	29	27	65	1	15	20
Vector Lines	0.0	16.1	28	16.1	n/a	3	4	0	0	0	0	0	0	12	21
Waipa Networks	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0	0	0	0	0
WEL Networks	0.2	1.1	10	0.9	+477.6	6	4	26	20	26	20	0	0	0	0
Wellington Electricity	2.6	2.7	14	0.1	+104.3	15	4	100	100	0	0	25	10	15	10
Westpower	0.7	0.4	35	-0.3	+58.0	0	0	0	0	4	4	0	0	11	11

Replacement and renewal of sub-transmission assets

168. The data disclosed on the condition and expected replacement rate of assets relating to sub-transmission and summarised in Table 6, shows that:

168.1 17 distributors forecast an increase in expenditure;

168.2 Six distributors forecast a decrease in expenditure;

168.3 typically, distributors are forecasting to replace less than 10% of their zone substation assets; and

168.4 as expected, those distributors with a small proportion of assets in grade 1 or 2 have forecast only a small proportion of their assets to be replaced.

169. Notably, not all distributors are forecasting to replace assets considered to require short term intervention. As discussed previously, this approach may increase the number of interruptions. Readers should refer to attachment B for information about each distributor's forecasts for reliability.

170. In addition, we note that some distributors may not own sub-transmission assets across all categories recorded, which may explain why many distributors have no expenditure planned.

Table 6: Asset health-driven expenditure on sub-transmission lines (%)

	Expenditure on sub-tranmission lines					Overhead conductor up to 66kV (%)		Underground XLPE up to 66kV (%)		Underground oil pressurised up to 66kV (%)	
	Annual			Forecast change							
	Estimate 2013 ($m)	Average 2014–18 ($m)	% of forecast asset replacment & renewal	2013 to 2014–18 ($m)	2013 to 2014–18 (%)	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018	Grade 1 & 2 2013	Forecast replaced 2018
Alpine Energy	0.0	0.0	0	0.0	n/a	3	3	0	0	0	0
Aurora Energy	2.8	1.7	19	-1.1	–40	35	0	0	0	0	0
Buller Electricity	0.1	0.1	14	0.0	0	0	0	0	0	0	0
Centralines	0.2	0.1	8	0.0	–20	2	1	0	0	0	0
Counties Power	0.0	0.0	0	0.0	–100	8	7	0	0	0	0
Eastland Network	0.5	0.8	12	0.3	+72	0	0	0	0	0	0
Electra	0.1	0.1	2	0.1	+140	18	2	0	0	0	0
Electricity Ashburton	0.0	0.4	27	0.4	n/a	0	0	0	0	0	0
Electricity Invercargill	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0
Horizon Energy	3.6	0.1	3	-3.4	–96	0	0	0	0	0	0
Mainpower NZ	0.1	0.5	14	0.4	+257	0	5	0	5	0	0
Marlborough Lines	1.1	2.7	37	1.7	+153	2	2	0	0	0	0
Nelson Electricity	0.0	0.0	0	0.0	n/a	100	0	0	0	0	0
Network Tasman	0.0	0.0	1	0.0	n/a	0	0	0	0	0	0
Network Waitaki	0.3	0.1	4	-0.2	–82	0	0	0	0	0	0
Northpower	0.0	1.0	11	1.0	n/a	25	0	95	0	1	0
Orion NZ	0.4	0.8	3	0.4	+114	0	1	0	0	0	0
OtagoNet	0.0	0.9	13	0.9	n/a	0	29	0	0	0	0
Powerco	2.5	5.3	13	2.8	+114	1	1	0	4	0	0
Scanpower	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0
The Lines Company	0.5	0.9	13	0.4	+99	0	0	0	0	0	0
The Power Company	0.7	4.1	52	3.4	+497	5	5	0	0	0	0
Top Energy	0.2	0.9	14	0.7	+349	89	0	0	0	0	0
Unison Networks	0.0	1.3	8	1.3	n/a	3	0	0	0	0	0
Vector Lines	0.0	5.8	10	5.8	n/a	0	0	0	5	3	3
Waipa Networks	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0
WEL Networks	0.0	0.0	0	0.0	n/a	0	0	0	0	0	0
Wellington Electricity	0.6	0.6	3	0.0	+5	1	1	0	0	15	15
Westpower	0.9	0.1	13	-0.8	–84	0	0	0	0	0	0

Capacity-driven investments on system growth

171. Forecast expenditure on system growth accounts for around 26% of the total capital expenditure forecast by the industry, and much of this expenditure is on these assets. However, many distributors are forecasting a decline in average expenditure on system growth relative to historic levels.

172. As shown in Figure 11, a significant proportion of individual distributor's planned expenditure on system growth is generally on zone substations and subtransmission assets. The data disclosed indicates that annual industry expenditure on system growth on these groups of assets is forecast to double relative to 2013 levels.[42]

173. We have analysed information disclosed about capacity-driven investments on system growth for the purpose of promoting greater understanding of each distributor's forecast changes in expenditure in this areas. This analysis also helps illustrate how the information disclosed could be used in a top down model to help explain forecast changes in expenditure on capacity growth for zone substations and subtransmission.

174. We have summarised and analysed information disclosed on:

    174.1 The current capacity of zone substations

    174.2 The expected capacity of zone substations in 2018 (in the absence of any additional investment); and

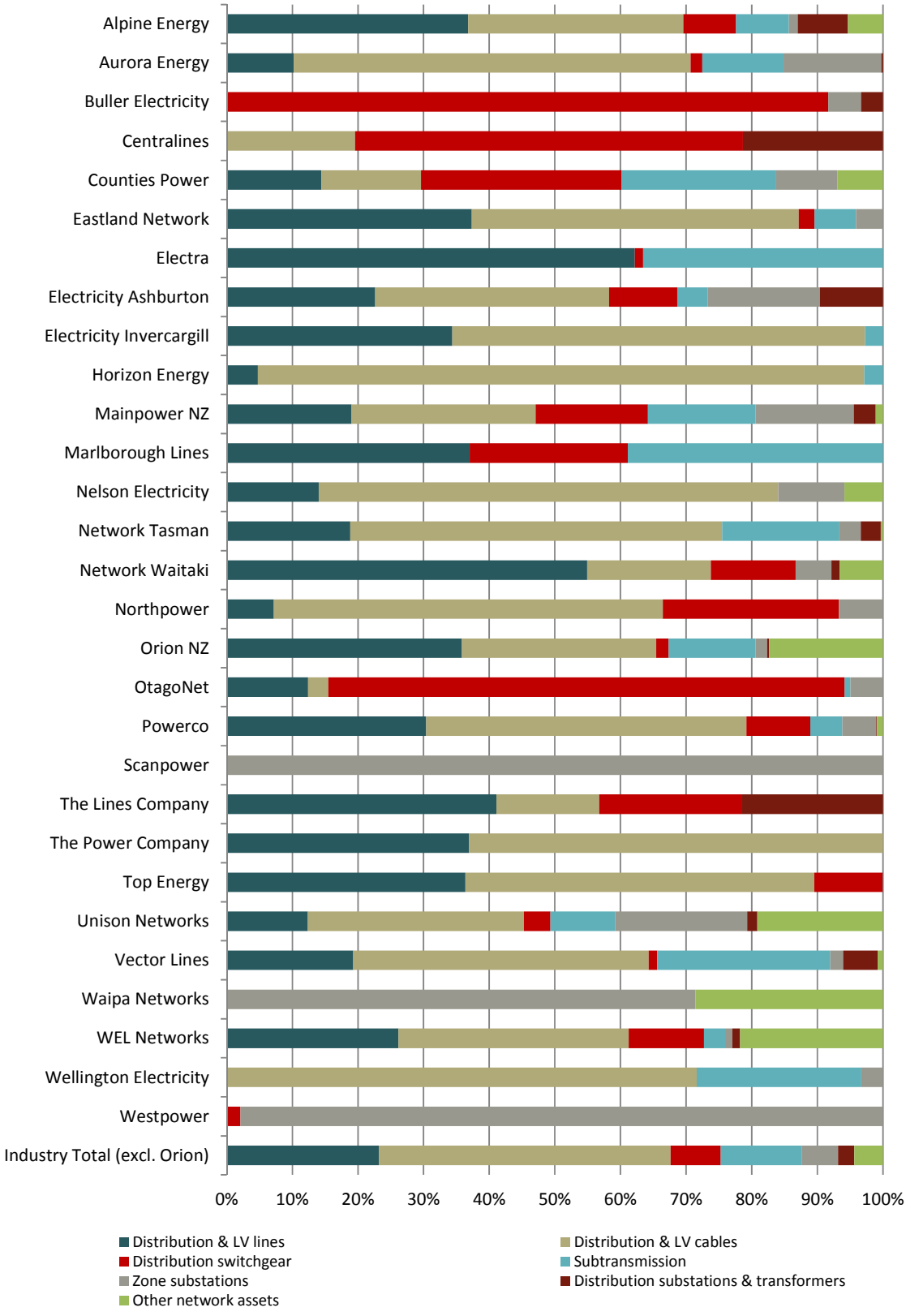
    174.3 Forecasts of growth in peak demand.

175. Our expectation is that distributors who are forecasting significant increases in expenditure on capacity growth for zone substations and subtransmission would have a high substation utilisation, ie, at 80% or more installed firm capacity, and/or are expecting a high proportion of their substation to have high utilisation by 2018 in the absence of investment.[43] We would also expect these distributors would be forecasting peak demand to increase. However, we recognise that this does not capture the location of changes in demand relative to the capacity available.

[42] Distributors were not previously required to disclose this information. Therefore we are unable to compare planned expenditure on sub transmission and zone substations with expenditure prior to 2013.

[43] This analysis of utilisation only includes substations with at least n-1 security.

Figure 11: Breakdown of forecast expenditure on system growth by asset category (annual average % for 2014-18)



176. Our analysis of the information disclosed and summarised in Table 7 indicates that:

176.1 all but two distributors forecast an increase in peak demand, but typically peak demand is forecast to increase by between 1% and 3% each year;

176.2 some distributors have a relatively high proportion of substations with a peak demand that exceeds 80% of installed firm capacity;

176.3 a number of distributors currently also have a number of substations with peak demand that exceeds 100% of installed firm capacity;

176.4 by 2018 and in the absence of any further investment, many distributors are forecasting firm capacity to increase at their substations;

176.5 by 2018 and in the absence of any further investment, most distributors are forecasting an increase in the proportion of zone substations with a peak demand that exceeds 80% of installed firm capacity;

176.6 by 2018 and in the absence of any further investment, many distributors are forecasting a decrease in the proportion of zone substations with a peak demand that exceeds 100% of installed firm capacity;

176.7 many distributors have a high proportion of their zone substations without n-1 security. We might expect these networks to have a higher number of interruptions relative to other networks.

Table 7: Capacity-driven capital expenditure on sub-transmission and zone substations

	Expenditure				Peak demand			Capacity and utilisation of zone substations								
	Annual		Change		Annual growth rate		Change	Total	Percentage of total – 2013 (%)				Percentage of total – 2018 (%)			Forecast growth in installed firm capacity 2013–18 (%)
	Estimate 2013 ($m)	Average 2014–18 ($m)	2013 to 2014–18 ($m)	2013 to 2014–18 (%)	Historic 2008–13 (%)	Forecast 2013–18 (%)	2008–13 to 2013–18 (% points)	Zone substations in 2013	Without n-1 security transformers	Firm capacity forecast to increase	Peak demand >80% installed firm capacity	Peak demand >100% installed firm capacity	Without n-1 security transformers	Peak demand >80% installed firm capacity	Peak demand >100% installed firm capacity	
Alpine Energy	4.6	4.0	−0.6	−13	−0.6	+2.7	+3.3	18	56	6	11	0	56	17	11	6
Aurora Energy	0.2	5.1	+4.9	+2234	+0.1	+1.0	+0.9	37	27	8	16	5	27	27	3	2
Buller Electricity	0.0	0.0	0.0	n/a	+5.6	+4.6	−1.0	3	0	67	0	0	0	33	0	45
Centralines	0.0	0.0	+0.0	n/a	−0.5	+1.0	+1.5	5	0	100	0	0	0	0	0	25
Counties Power	0.3	1.9	+1.6	+631	+1.1	+3.0	+1.9	9	33	67	33	22	33	33	11	31
Eastland Network	0.5	4.9	+4.4	+981	−0.3	+3.0	+3.3	19	5	0	16	16	5	16	16	0
Electra	0.0	0.5	+0.4	+1271	−0.4	+1.6	+2.1	10	0	0	10	0	0	20	0	0
Electricity Ashburton	0.4	3.7	+3.3	+759	+4.5	+3.3	−1.2	22	82	23	9	5	82	9	0	133
Electricity Invercargill	2.6	1.0	−1.6	−61	+0.3	+1.5	+1.2	4	50	25	25	0	50	50	0	0
Horizon Energy	0.7	1.8	+1.1	+152	−0.4	+1.4	+1.9	7	57	14	29	29	57	29	29	9
Mainpower NZ	3.5	2.7	−0.8	−22	+3.0	+2.9	−0.1	19	32	16	32	32	32	37	37	77
Marlborough Lines	3.6	0.2	−3.4	−94	+0.4	+2.1	+1.6	15	20	6	27	7	19	94	94	11
Nelson Electricity	3.2	1.2	−2.0	−63	−1.3	+1.0	+2.3	1	0	100	100	0	0	0	0	20
Network Tasman	0.5	4.6	+4.2	+913	+0.3	−0.7	−1.0	11	36	0	9	0	36	45	0	0
Network Waitaki	1.2	1.8	+0.5	+41	−0.0	+5.8	+5.8	13	23	6	8	8	18	12	6	19
Northpower	0.2	1.4	+1.3	+847	+1.8	+1.6	−0.1	19	37	5	42	26	37	53	26	3
Orion NZ	10.5	24.3	+13.8	+132	−1.8	+1.4	+3.2	51	0	9	31	2	0	47	9	7
OtagoNet	0.0	0.2	+0.2	n/a	+1.6	+1.0	−0.6	33	82	0	24	12	82	24	18	0
Powerco	20.4	19.8	−0.7	−3	+2.2	+1.2	−1.0	114	43	20	49	33	43	54	34	19
Scanpower	0.0	0.0	0.0	n/a	−0.4	+2.8	+3.2	0	*	*	*	*	*	*	*	n/a
The Lines Company	0.8	0.5	−0.3	−33	+1.0	+0.8	−0.2	28	75	7	25	4	75	29	7	-35
The Power Company	0.0	6.2	+6.2	n/a	+4.1	+2.2	−1.9	35	51	14	26	14	51	20	9	20
Top Energy	9.1	5.7	−3.4	−38	+0.6	+1.1	+0.4	12	33	17	25	8	33	33	17	27
Unison Networks	0.0	2.7	+2.7	n/a	−4.2	0.0	+4.2	33	33	70	36	12	33	21	6	34
Vector Lines	0.0	24.7	+24.7	n/a	−0.0	+1.6	+1.6	109	28	14	67	50	28	70	55	12
Waipa Networks	0.0	0.0	0.0	n/a	+3.3	+2.0	−1.3	2	0	0	100	0	0	100	0	0
WEL Networks	2.0	12.5	+10.4	+514	+0.3	+2.8	+2.4	29	31	24	28	10	31	21	0	21
Wellington Electricity	2.7	5.3	+2.6	+98	+1.1	+0.9	−0.1	28	0	0	36	14	0	50	18	0
Westpower	0.0	0.0	0.0	n/a	+2.6	+3.2	+0.6	20	60	0	10	0	60	10	10	0

* Did not disclose

Attachment B: Targets for service quality

Purpose of chapter

177. The purpose of this chapter is to summarise the information disclosed on distributor's expectations of future changes in the level of quality they provide. Analysis of this information can:

177.1 help to understand whether distributors are planning to provide services at a quality that consumer demands; and

177.2 assist in understanding and assessing the level and timing of expenditure forecast by distributors.

178. We seek your views on the analysis provided and whether the current measures disclosed appropriately reflect those aspects of service quality that matter to consumers.

Quality should reflect consumer demands and their willingness to pay

179. Dimensions of quality can include the availability of the service, the speed at which interrupted services are restored, and consumer experiences of any interactions with the distributor.

180. Quality is an important aspect of the service received by consumers, alongside the price. The significance of quality is reflected in Part 4 of the Commerce Act; incentives to provide services at a quality that reflects consumer demands is one of the listed regulatory objectives. For those 17 distributors that are subject to a price cap, the Commission is required to specify within the price-quality paths it sets the quality standards that must be met.[44] All distributors are also required to publicly disclosed information on the quality of service provided.

181. The quality of electricity distribution services supplied to consumers is currently largely measured by the number and duration of interruptions experienced by consumers. Distributors are required to disclose data on the following metrics:

181.1 System Average Interruption Frequency Index (SAIFI) per connection; and

181.2 System Average Interruption Duration Index (SAIDI) per connection.

182. In considering the level of quality provided, it is important to consider that there is a trade-off between the quality and price of a service. A consumer may be willing to forgo quality in order to pay a lower charge, or may be willing to pay a higher charge in order to get a higher level of quality.

[44] Refer: s 53M(1)(b) of the Act.

Quality of service experienced by consumers in 2013

183. Figure 12 and Figure 13 summarise the expected frequency and duration of interruptions in 2013. The SAIDI and SAIFI scores are shown split by whether they are planned (Class B) or an unplanned (Class C) interruption and are normalised to exclude the impact of major event days. For those distributors that are subject to price-quality regulation, the graphs show the quality standards set for these distributors.[45]

184. The analysis shows that:

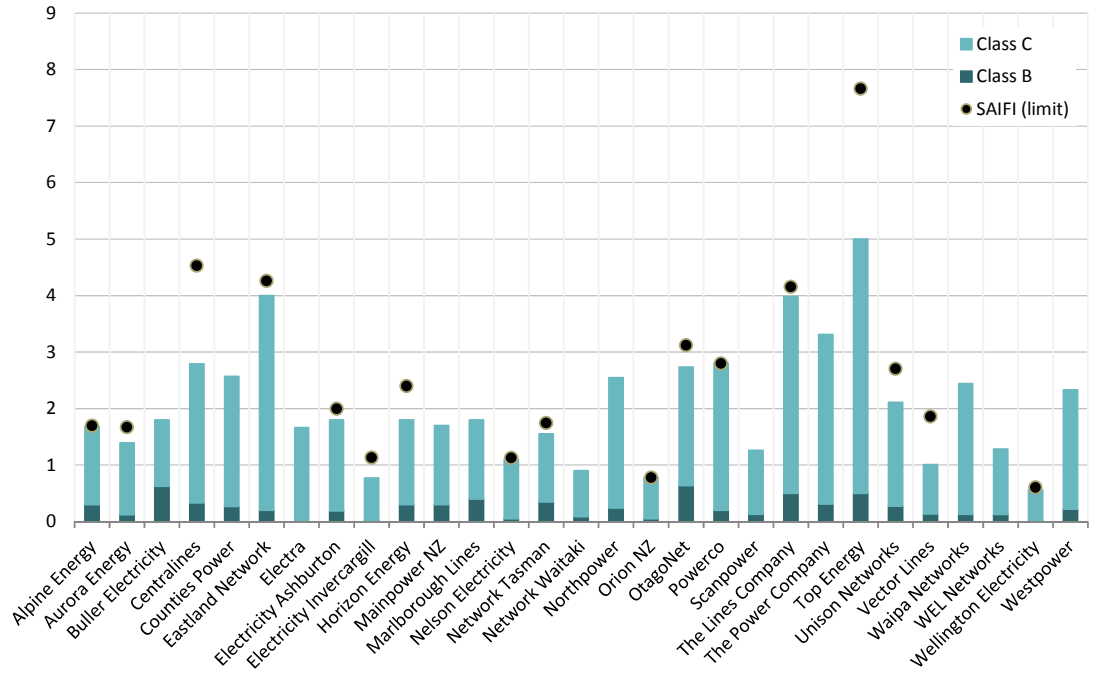
184.1 expected SAIFI in 2013 ranges from 0.56 to 5 interruptions per connection;

184.2 expected SAIDI in 2013 ranges from 40 to 402 minutes per connection; and

184.3 of those distributors subject to price-quality regulation, a number of distributors are outperforming the minimum quality standards while others are slightly exceeding these.[46]

185. SAIFI and SAIDI may vary across networks for a number of reasons, including different network characteristics.

Figure 12: Expected SAIFI (2013)

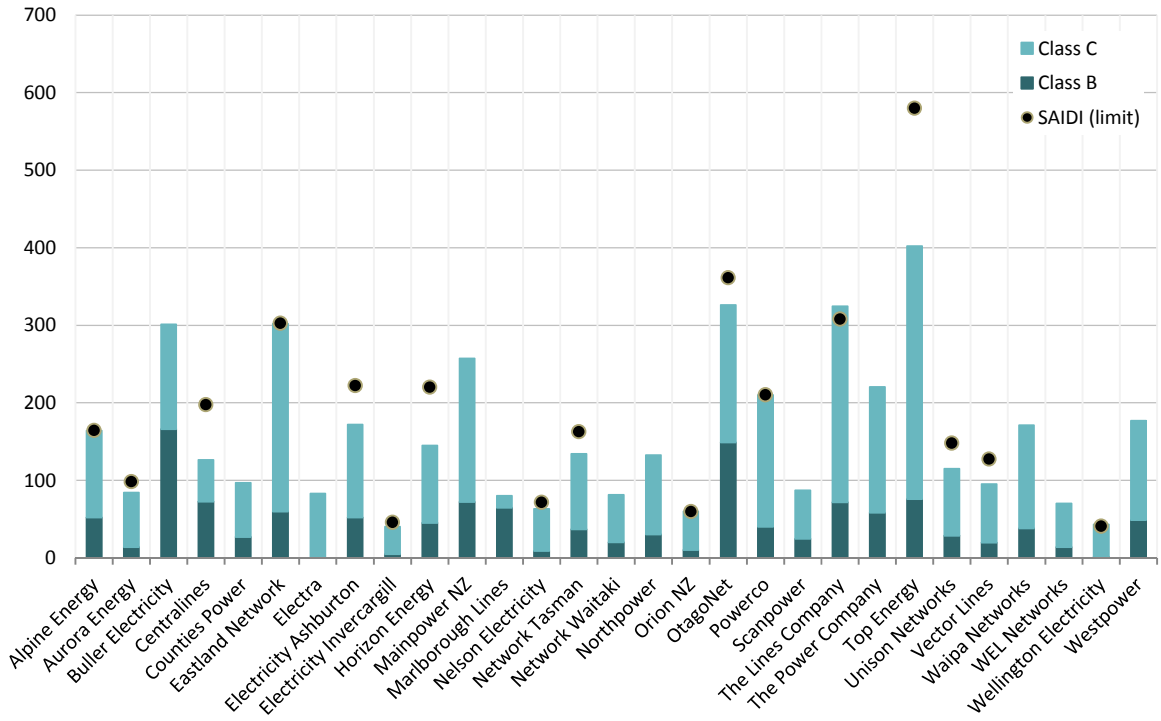


Note: The SAIFI figures that are shown have not been adjusted for maximum event days.

[45] The Commission does not set explicit quality standards for distributors that are not subject to price-quality regulation.

[46] It may not be a concern if a distributor exceeds the minimum quality standard in a single year.

Figure 13: Expected SAIDI (2013)



Note: The SAIDI figures that are shown have not been adjusted for maximum event days.

Distributor expectations of the service of quality to be provided

186. As discussed in the previous chapter, decisions about the level and location of expenditure on a network can have an impact on SAIDI and SAIFI. It is expected that a distributor that does not maintain its assets or invest in replacing assets in poor condition will have a higher number and duration of interruptions relative to a distributor with assets in better condition. This is not necessarily a concern if the resulting quality appropriately reflects consumer demands given the trade-off between reduced expenditure (and therefore lower prices) and lower quality.

187. We have examined the expected change in the number and duration of interruptions in 2018 relative to historic levels (ie, 2008-13), as disclosed by distributors. The data disclosed reveals that:

187.1 20 distributors are forecasting a decrease in the number of interruptions. Of these, 18 are also forecasting a decrease in the duration of these interruptions.

187.2 9 distributors are forecasting an increase in the number of interruptions. Of these, two are also forecasting an increase in the duration of these interruptions.

188. To put these changes in quality in context, they should be considered alongside forecast changes in expenditure, including on asset replacement and renewal. We might expect to see that a distributor whose planned expenditure does not reflect the condition of its assets will expect an increase in interruptions relative to historic levels. Similarly, a distributor that is planning significant investment in its network to improve the condition of its assets would be expected to be also forecasting a decline in interruptions. Attachment A summarises forecast information on asset condition and expenditure on asset replacement and renewal.

Additional measures of quality

189. SAIDI and SAIFI capture interruptions to the service, and may not capture other aspects of service quality that matter to consumers. The disclosed SAIDI and SAIFI are also at an aggregate network level and may not therefore capture different interruptions experienced by different types of customers (for example, rural or urban customers). An Electricity Networks Association (ENA) working group is currently exploring what other aspects of quality should be considered (for example, level of customer communication during a power outage), and how these can be captured. The group is expected to report its findings this year. We support the establishment of such a group and look forward to its findings.

Table 8: Forecast changes in reliability

	SAIFI			SAIDI		
	Average 2008-13	Forecast 2018	Change (%)	Average 2008-13	Forecast 2018	Change (%)
Alpine Energy	1.70	1.69	−1	206	151	−27
Aurora Energy	1.44	1.33	−8	101	80	−21
Buller Electricity	1.92	1.62	−16	274	271	−1
Centralines	3.53	4.22	+20	179	198	+10
Counties Power	2.63	2.50	−5	123	90	−27
Eastland Network	3.61	4.00	+11	305	302	−1
Electra	2.21	1.66	−25	207	83	−60
Electricity Ashburton	1.78	1.72	−3	225	199	−11
Electricity Invercargill	1.01	1.00	−1	44	40	−10
Horizon Energy	2.10	1.80	−14	152	140	−8
Mainpower NZ	1.69	1.54	−9	184	118	−36
Marlborough Lines	2.41	1.70	−29	257	180	−30
Nelson Electricity	0.93	0.90	−4	76	45	−40
Network Tasman	1.59	1.36	−14	170	115	−32
Network Waitaki	1.22	0.90	−26	70	81	+15
Northpower	2.95	2.54	−14	264	145	−45
Orion NZ	0.96	1.02	+6	92	82	−10
OtagoNet	2.75	2.48	−10	333	292	−12
Powerco	2.63	2.80	+6	277	210	−24
Scanpower	1.18	0.92	−22	75	83	+11
The Lines Company	3.67	4.15	+13	298	308	+3
The Power Company	3.38	2.88	−15	230	193	−16
Top Energy	6.29	3.50	−44	579	245	−58
Unison Networks	2.04	2.43	+19	142	133	−6
Vector Lines	1.26	1.24	−2	122	107	−12
Waipa Networks	2.14	2.37	+11	167	166	−1
WEL Networks	1.30	1.30	−0	77	70	−9
Wellington Electricity	0.56	0.58	+3	38	38	−1
Westpower	2.22	2.33	+5	237	177	−25

Note: The figures shown do not include any adjustments for maximum event days.

Attachment C: Energy efficiency, demand side management and line losses

Purpose of attachment

190. This attachment provides some initial observations of information disclosed by distributors in relation to energy efficiency, demand side management and line losses. Analysis of this information can assist in particularly assessing whether distributors:

    190.1 are investing and operating their network efficiently, including innovating where appropriate;

    190.2 have incentives to invest in energy efficiency, demand side management and reductions in losses.

191. We are interested in views on our initial observations of information disclosed in this area. This includes views on what further analysis distributors and other interested persons would find useful in this area, and what the relative priorities are between energy efficiency, demand side management and reduction in losses.

A feature of the Commerce Act

192. Investment in energy efficiency, demand side management and reduction in losses may result in improvements in the efficiency of a distributor's expenditure.[47] For example, distributors may be able to avoid investment in additional capacity by undertaking lower cost activities that encourage consumers to reduce peak demand. Ultimately, improvements in the efficiency of a distributor's expenditure can result in lower prices for consumers.

193. Section 54Q of the Commerce Act requires that "the Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services". We must therefore consider whether our regulation is incentivising or dis-incentivising distributors from investing in energy efficiency, demand side management and activities to reduce energy losses.[48]

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[47] Energy efficiency, demand side management and reduction in losses may therefore promote the purpose of Part 4.

[48] In considering how we can promote investment in energy efficiency, demand side management and reduction in losses we must also ensure that in doing so we are not inconsistent with the Part 4 purpose and are acting within the constraints of other parts of Part 4.

194. Trust-owned distributors have an objective under the Energy Companies Act to have regard to the efficient use of energy, while meeting the principle objective of operating as a successful business.[49]

The ENA has set up a working group

195. The ENA working group on energy efficiency includes representatives from a number of distributors. They are also attended by staff from the Commission.[50] The work undertaken by this group is intended to include:

195.1 defining what it meant by energy efficiency and demand side management;

195.2 identifying what opportunities currently exist for distributors to improve energy efficiency, demand side management and reduce losses

195.3 understanding what further activities could be undertaken by distributors in this area that would be beneficial for consumers

195.4 considering incentives on distributors to invest in energy efficiency, demand side management and line losses, including incentives under Part 4

196. The group is expected to report on its findings in December 2013. We support the establishment of an industry group to examine these issues and look forward to its findings.

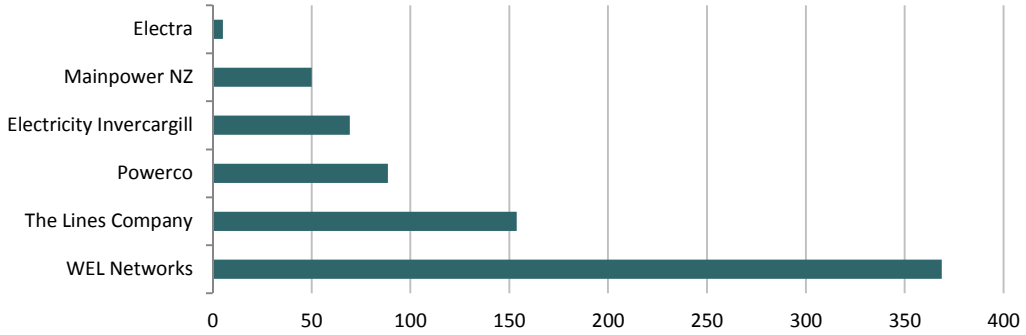
Initial observations of information disclosed

197. Only a small number of distributors are forecasting any expenditure on energy efficiency, demand side management and reduction in line losses. Figure 14 shows that, of those five distributors that have forecast any expenditure in this area, the amount forecast per connection varies from $5 to $369 per year on average between 2013 and 2023.

[49] S 36 of the 1992 Energy Companies Act

[50] Commission staff attend these working groups as observers only. Any comment made by Commission staff is not a Commission view or opinion.

Figure 14: Forecast annual expenditure on energy efficiency, demand side management and reduction in losses ($ per connection 2013-23)



198. It is unclear why many distributors have not forecast any expenditure on energy efficiency, demand side management and reduction in line losses. We invite views on this point. For example, this could be because:

198.1 expenditure on energy efficiency, demand side management and reduction in losses cannot be distinguished from expenditure in other areas; [51]

198.2 distributors do not expect to incur any expenditure in this area. For example, it may not be cost-effective at this time for a distributor to undertake activities to improve energy efficiency, demand side management or to reduce losses, or others (eg, retailers) may be better placed to undertake these activities; or

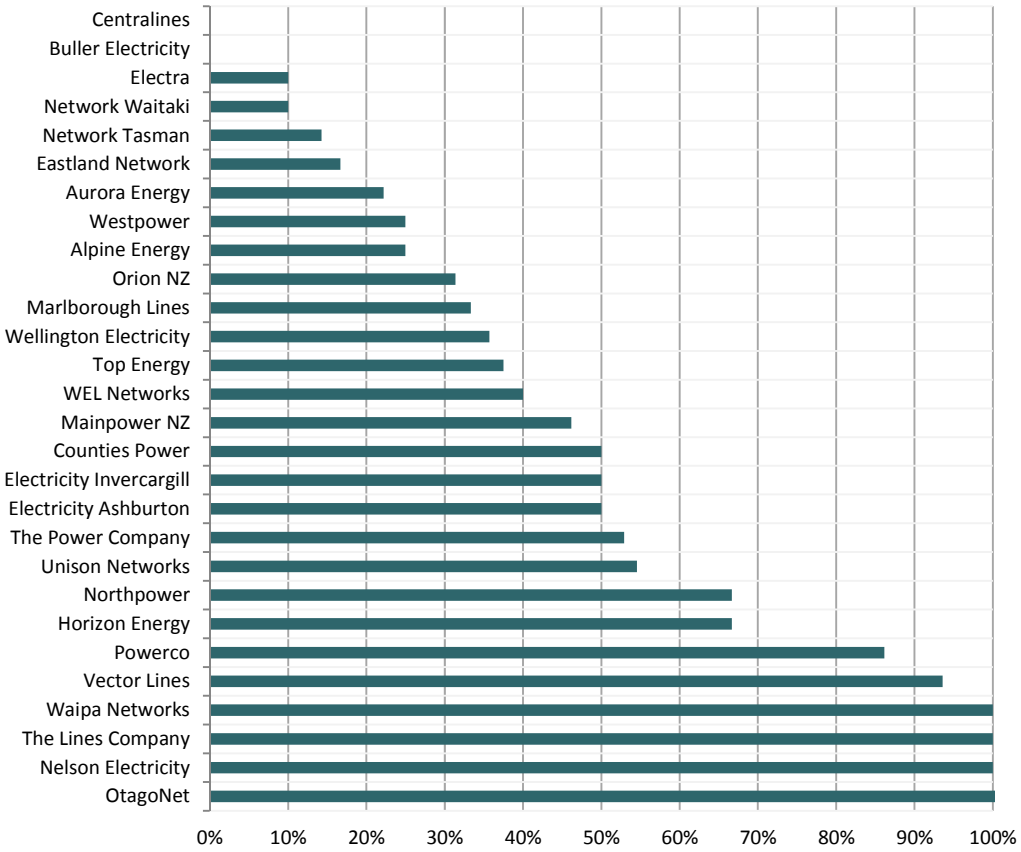
198.3 this type of expenditure is difficult to forecast. For example, distributors may be unsure what technology will exist in the future that they will be able to utilise for demand side management.

199. In order to help understand whether there are opportunities and benefits from distributors improving their energy efficiency and demand side management we have summarised below substation utilisation for each distributor. It may be more economic for distributors with limited capacity, ie, high substation utilisation, to improve their energy efficiency and undertake more demand side management rather than to increase capacity.

[51] Disclosure of forecast expenditure on energy efficiency, demand side management and reduction in losses was only required if known.

200. The figure below shows that many distributors currently have a high proportion of their zone substations with utilisation over 80%.[52] Four distributors report that currently all of their zone substations (with at least n-1 security) have utilisation over 80%. Most of those distributors with high utilisation across their network have not forecast any expenditure to energy efficiency, demand side management or reduction in losses. As shown in attachment A, many distributors are forecasting an increase in substation utilisation by 2018 in the absence of any additional investment.

Figure 15: Proportion of zone substations with peak demand > 80% of installed firm capacity (2013)



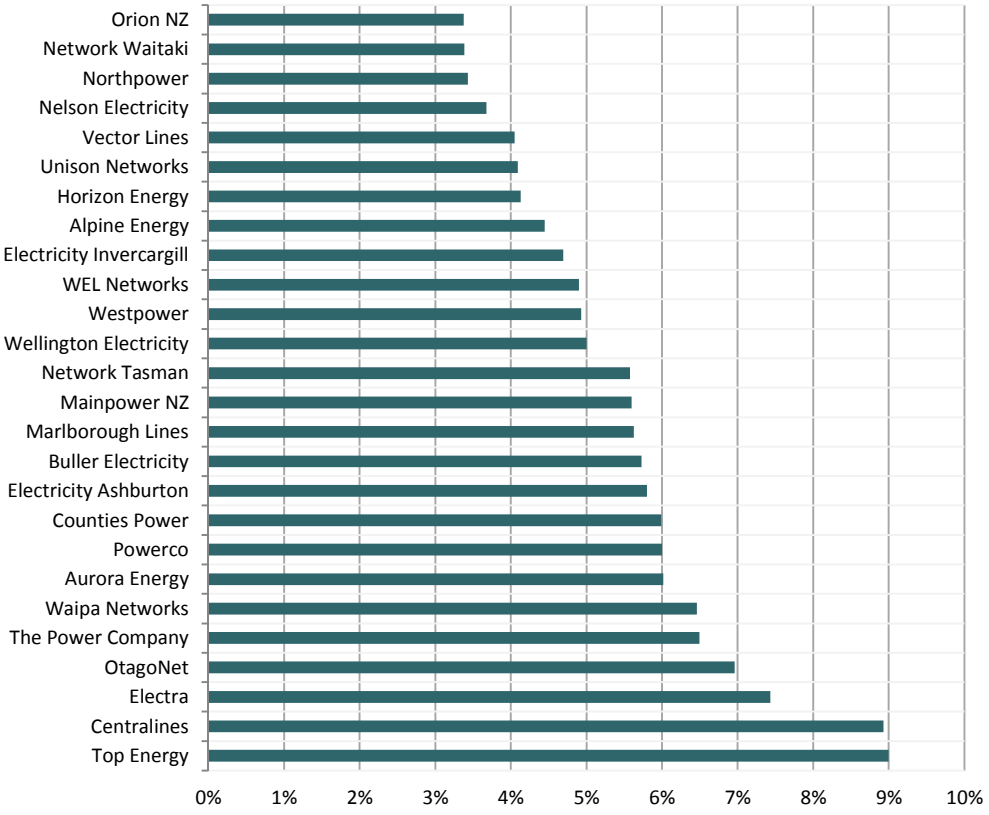
Note: Scanpower is excluded as it did not disclose information on substation utilisation.

[52] Utilisation is measured only for those zone substations without n-1 security.

201. We have also examined the loss rate for each distributor in 2013. Relatively high losses may indicate there is potential for reductions in losses and therefore improvements in efficiency.[53] We recognise however that reducing losses may not necessarily be the most cost-effective option as lower losses may be associated with lower utilisation of assets, and therefore higher costs.

202. Figure 16 shows that the reported loss ratio for 2013 differs across distributors. Eastland Network, The Lines Company and Scanpower are excluded from these graphs as these distributors report potentially erroneous loss ratios of less than 0.1% (Eastland Network) and 100% (The Lines Company and Scanpower).

Figure 16: Loss ratio (2013)



[53] However, measurements of the amount of energy lost can be affected by metering errors. This may mean the resulting figure is not a full representation of the potential scope for the distributors to reduce electrical losses.

Attachment D: Supplementary tables

Purpose of attachment

203. This attachment contains tables with a more detailed breakdown of expenditure information for each electricity distribution business. This includes:

    203.1 Breakdown by category of annual average capital expenditure between 2010 and 2013;

    203.2 Breakdown by category of changes in capital expenditure from 2010-13 to 2014-18;

    203.3 Breakdown by category of annual average operating expenditure between 2010 and 2013;

    203.4 Breakdown by category of changes in operating expenditure from 2010-13 to 2014-18;

204. All the analysis in this attachment was undertaken in constant (2013) prices. Any conversion of nominal figures was undertaken using the Capital Goods Price Index for capital expenditure, and for operating expenditure we used a weighted average of the Labour Cost Index and Producer Price Index.

205. In addition:

    205.1 the disclosed estimate for 2013 has been included when calculating the historic average expenditure, ie, for 2010-13; and

    205.2 ‘other operating expenditure’ is not a category under the revised disclosure requirements, so for that reason ‘n/a’ appears in the column showing changes for that category.

Table 9: Capital expenditure - Historic breakdown by category

Average annual capital expenditure (2010-13)

	In dollars million ($m, 2013 prices)							As a percentage of total (%)						
	Asset replacement & renewal	System growth	Consumer connection	Reliability, safety & environment	Asset relocations	Non-network	**Total**	Asset replacement & renewal	System growth	Consumer connection	Reliability, safety & environment	Asset relocations	Non-network	**Total**
Alpine Energy	1.9	9.0	2.2	2.3	0.0	0.3	**15.7**	12	57	14	15	0	2	**100**
Aurora Energy	5.9	5.3	5.6	1.8	1.2	0.0	**19.8**	30	27	28	9	6	0	**100**
Buller Electricity	0.6	0.1	0.4	0.4	0.0	0.1	**1.6**	35	9	24	23	2	7	**100**
Centralines	1.4	0.6	0.3	2.0	0.0	0.2	**4.5**	31	13	7	44	1	5	**100**
Counties Power	4.1	3.7	2.1	1.7	0.2	-1.1	**10.7**	39	35	20	15	2	-11	**100**
Eastland Network	4.1	0.7	0.1	0.1	0.0	0.3	**5.4**	77	13	1	3	0	6	**100**
Electra	3.4	1.3	0.0	1.7	0.2	0.1	**6.7**	50	19	1	26	3	2	**100**
Electricity Ashburton	2.7	6.1	2.7	2.3	0.0	2.6	**16.5**	16	37	16	14	0	16	**100**
Electricity Invercargill	1.2	1.1	0.3	1.0	0.1	0.3	**4.0**	32	27	7	24	2	9	**100**
Horizon Energy	2.3	0.5	0.4	2.4	0.0	0.9	**6.5**	36	7	6	37	1	13	**100**
Mainpower NZ	2.2	3.9	5.6	1.7	0.1	1.6	**15.2**	15	26	37	11	1	11	**100**
Marlborough Lines	5.3	4.1	0.3	3.8	0.4	0.9	**14.7**	36	28	2	26	3	6	**100**
Nelson Electricity	0.9	1.0	0.0	0.3	0.0	0.0	**2.3**	38	45	1	14	0	2	**100**
Network Tasman	1.4	0.9	0.9	1.0	0.7	0.3	**5.3**	27	17	16	20	14	5	**100**
Network Waitaki	0.9	2.9	0.3	0.7	0.0	0.1	**5.0**	18	57	7	14	0	3	**100**
Northpower	7.2	1.6	0.5	0.3	0.1	0.5	**10.4**	70	16	5	3	1	5	**100**
Orion NZ	15.3	15.5	6.9	5.6	2.9	10.6	**56.9**	27	27	12	10	5	19	**100**
OtagoNet	5.2	1.5	1.3	0.6	0.1	0.1	**8.7**	60	17	15	7	1	1	**100**
Powerco	26.9	23.3	20.1	12.9	1.8	4.5	**89.5**	30	26	22	14	2	5	**100**
Scanpower	1.0	0.0	0.0	0.0	0.0	0.0	**1.1**	87	3	2	4	0	4	**100**
The Lines Company	4.4	1.1	1.2	1.2	0.0	0.3	**8.2**	53	14	15	14	0	4	**100**
The Power Company	6.9	6.3	3.3	0.6	0.1	0.5	**17.6**	39	36	19	3	0	3	**100**
Top Energy	3.3	7.2	1.1	4.5	0.1	0.3	**16.5**	20	44	7	27	0	2	**100**
Unison Networks	10.7	3.7	9.8	4.9	1.1	4.6	**34.8**	31	11	28	14	3	13	**100**
Vector Lines	55.3	38.5	22.6	3.3	19.0	10.7	**149.3**	37	26	15	2	13	7	**100**
Waipa Networks	0.6	0.4	1.5	2.2	0.3	0.6	**5.7**	11	7	27	39	5	10	**100**
WEL Networks	6.9	16.9	6.5	2.0	3.4	7.1	**42.9**	16	39	15	5	8	17	**100**
Wellington Electricity	8.3	2.3	5.8	7.4	1.0	5.2	**30.0**	28	8	19	25	3	17	**100**
Westpower	2.7	0.5	0.2	1.5	0.0	0.1	**5.1**	53	11	4	30	1	1	**100**
Industry (excl. Orion NZ)	177.6	144.5	95.2	64.7	30.0	41.2	**553.3**	32	26	17	12	5	7	**100**

Table 10: Capital expenditure - Forecast change by category

Forecast change in average annual capital expenditure (2014-18 vs. 2010-13)

	In dollars million ($m, 2013 prices)							In percentage terms (%)						
	Asset replacement & renewal	System growth	Consumer connection	Reliability, safety & environment	Asset relocations	Non-network	**Total change**	Asset replacement & renewal	System growth	Consumer connection	Reliability, safety & environment	Asset relocations	Non-network	**Total change**
Alpine Energy	+0.9	−3.2	+0.0	−0.5	0.0	+0.4	**−2.4**	+50	−36	+0	−23	n/a	+123	**−15**
Aurora Energy	+2.9	+1.9	+0.2	−0.6	+1.4	0.0	**+5.8**	+49	+36	+3	−32	+120	n/a	**+29**
Buller Electricity	−0.0	−0.1	−0.3	−0.2	+0.0	−0.0	**−0.6**	−1	−59	−74	−55	+98	−34	**−36**
Centralines	+0.1	−0.3	−0.1	−1.5	+0.1	+0.1	**−1.6**	+8	−61	−20	−75	+226	+56	**−35**
Counties Power	−0.4	+2.6	+0.0	+0.1	−0.0	+1.2	**+3.6**	−10	+71	+0	+7	−18	−110	**+33**
Eastland Network	+2.4	+4.9	+0.0	+0.3	+0.0	−0.0	**+7.6**	+58	+711	+25	+206	+136	−7	**+142**
Electra	+2.5	−0.5	+0.1	+0.1	−0.1	−0.1	**+1.9**	+75	−39	+139	+5	−77	−100	**+28**
Electricity Ashburton	−1.3	+0.3	+0.3	+1.5	+0.0	−1.8	**−1.0**	−48	+4	+10	+66	n/a	−70	**−6**
Electricity Invercargill	+0.7	−0.0	−0.1	−0.9	−0.0	+0.2	**−0.1**	+59	−1	−27	−93	−55	+45	**−3**
Horizon Energy	+1.9	+1.4	+0.4	−0.6	−0.0	−0.3	**+2.8**	+82	+308	+90	−24	−49	−34	**+42**
Mainpower NZ	+1.5	+1.9	+1.4	+0.6	−0.1	+2.3	**+7.7**	+67	+50	+26	+33	−78	+145	**+51**
Marlborough Lines	+2.2	−3.5	−0.0	−0.5	−0.0	+0.2	**−1.6**	+41	−87	−7	−12	−4	+28	**−11**
Nelson Electricity	+0.0	+0.4	−0.0	−0.1	0.0	−0.0	**+0.3**	+3	+39	−100	−23	n/a	−61	**+13**
Network Tasman	+0.2	+5.2	+0.0	−0.5	+0.8	+0.0	**+5.8**	+16	+571	+5	−49	+107	+10	**+110**
Network Waitaki	+0.3	−0.5	+0.1	+0.3	−0.0	+0.7	**+0.8**	+29	−17	+17	+42	−42	+505	**+17**
Northpower	+1.8	+0.5	+0.2	+0.4	−0.0	−0.1	**+2.7**	+24	+33	+36	+108	−16	−23	**+26**
Orion NZ	+10.1	+21.6	+6.3	−4.4	+1.0	−6.7	**+27.8**	+66	+139	+91	−79	+34	−63	**+49**
OtagoNet	+2.0	−0.5	+0.2	+0.6	−0.0	+0.0	**+2.3**	+39	−35	+14	+110	−33	+12	**+26**
Powerco	+14.1	+1.7	−3.5	+7.3	+0.4	+1.6	**+21.6**	+53	+7	−18	+57	+22	+36	**+24**
Scanpower	−0.4	+0.1	+0.1	+0.9	+0.6	−0.0	**+1.2**	−43	+436	+384	+1823	n/a	−100	**+108**
The Lines Company	+2.8	−0.2	−0.1	+0.4	+0.0	−0.1	**+2.8**	+63	−20	−6	+34	+122	−23	**+35**
The Power Company	+1.0	−0.0	−0.6	+1.2	−0.0	+0.5	**+2.1**	+14	−0	−17	+194	−24	+106	**+12**
Top Energy	+3.5	−0.8	−0.1	+3.3	−0.1	−0.0	**+5.9**	+108	−11	−5	+73	−100	−11	**+36**
Unison Networks	+5.5	+2.3	−2.5	−2.1	+0.3	−0.6	**+2.9**	+51	+62	−26	−43	+29	−14	**+8**
Vector Lines	+2.0	−0.0	+0.5	+2.0	+0.5	+0.5	**+5.5**	+4	−0	+2	+61	+3	+5	**+4**
Waipa Networks	+0.1	−0.1	+0.1	+2.1	+0.4	+0.3	**+2.8**	+12	−35	+6	+94	+135	+51	**+49**
WEL Networks	+4.6	+3.4	+0.8	+0.1	−0.8	−2.3	**+5.9**	+67	+20	+12	+6	−23	−33	**+14**
Wellington Electricity	+10.4	+5.2	+0.9	−6.7	+0.1	−3.8	**+6.0**	+124	+229	+16	−90	+7	−75	**+20**
Westpower	−1.6	−0.1	−0.1	−1.0	−0.0	−0.1	**−2.8**	−58	−11	−54	−63	−100	−100	**−55**
Industry (excl. Orion NZ)	+60.0	+21.9	−2.0	+6.1	+3.4	−1.3	**+88.1**	+34	+15	−2	+9	+11	−3	**+16**

Table 11: Operating expenditure - Historic breakdown by category

Average annual operating expenditure (2010-13)

	In dollars million ($m, 2013 prices)							As a percentage of total (%)						
	Routine & preventative maintenance	Service interruptions & emergencies	Asset replacement & renewal	Business support	System operations & network support	Other	**Total**	Routine & preventative maintenance	Service interruptions & emergencies	Asset replacement & renewal	Business support	System operations & network support	Other	**Total**
Alpine Energy	2.7	0.9	1.1	3.4	4.3	0.3	**12.7**	21	7	9	27	34	2	**100**
Aurora Energy	3.6	4.4	1.3	3.4	4.0	0.5	**17.2**	21	26	8	20	23	3	**100**
Buller Electricity	0.5	0.2	0.4	1.1	0.3	0.0	**2.6**	21	7	16	43	13	0	**100**
Centralines	0.6	0.3	0.5	1.3	0.3	0.0	**3.2**	20	10	17	42	11	0	**100**
Counties Power	1.2	1.6	0.9	4.3	1.8	0.0	**9.8**	13	16	9	44	19	0	**100**
Eastland Network	1.3	1.0	0.2	2.5	1.2	0.1	**6.3**	20	16	3	40	20	1	**100**
Electra	2.3	1.5	0.8	2.0	1.4	0.2	**8.2**	29	19	9	25	17	2	**100**
Electricity Ashburton	1.2	0.5	0.2	2.8	2.1	0.0	**6.8**	18	7	2	41	31	0	**100**
Electricity Invercargill	0.7	0.5	0.2	1.6	0.8	0.2	**4.0**	17	13	5	39	20	5	**100**
Horizon Energy	1.2	0.7	0.4	3.3	1.8	0.0	**7.4**	16	9	6	45	24	0	**100**
Mainpower NZ	2.3	1.0	0.1	6.9	0.4	0.0	**10.8**	21	9	1	64	4	0	**100**
Marlborough Lines	5.2	1.1	1.2	6.5	0.7	0.2	**14.8**	35	7	8	44	5	1	**100**
Nelson Electricity	0.3	0.1	0.2	1.2	0.3	0.0	**2.1**	12	6	7	59	16	0	**100**
Network Tasman	1.6	0.6	1.6	2.5	1.9	0.0	**8.3**	19	8	20	31	23	0	**100**
Network Waitaki	0.7	0.2	0.7	0.5	1.2	0.0	**3.4**	22	7	20	16	35	0	**100**
Northpower	1.9	1.4	3.1	5.9	1.6	1.4	**15.2**	12	9	21	39	10	9	**100**
Orion NZ	12.7	9.7	2.3	15.3	11.9	0.5	**52.4**	24	19	4	29	23	1	**100**
OtagoNet	1.3	1.5	0.7	1.7	0.4	0.0	**5.6**	23	27	13	30	8	0	**100**
Powerco	13.6	6.6	7.8	24.8	9.1	0.0	**61.9**	22	11	13	40	15	0	**100**
Scanpower	0.2	0.3	0.4	0.9	0.3	0.1	**2.0**	9	13	18	44	13	3	**100**
The Lines Company	1.7	0.9	0.1	2.7	2.9	0.0	**8.3**	20	10	1	33	35	0	**100**
The Power Company	2.4	2.0	0.7	2.6	3.5	0.2	**11.3**	21	17	6	23	31	2	**100**
Top Energy	3.1	1.4	1.8	4.2	2.5	0.1	**13.1**	24	11	14	32	19	0	**100**
Unison Networks	4.3	3.7	1.4	15.3	4.9	0.0	**29.7**	14	13	5	52	17	0	**100**
Vector Lines	16.4	12.6	11.0	39.7	12.5	1.8	**94.0**	17	13	12	42	13	2	**100**
Waipa Networks	1.6	0.5	0.2	1.7	1.1	0.0	**5.0**	31	11	4	33	21	0	**100**
WEL Networks	3.3	2.5	1.2	6.1	4.0	1.0	**18.1**	18	14	7	34	22	5	**100**
Wellington Electricity	6.4	4.1	0.6	8.8	10.0	0.0	**29.8**	21	14	2	29	34	0	**100**
Westpower	3.5	0.8	0.7	1.4	1.4	0.0	**7.9**	45	10	9	18	18	0	**100**
Industry (excl. Orion NZ)	84.8	52.9	39.4	159.1	76.9	5.9	**419.0**	20	13	9	38	18	1	**100**

Table 12: Operating expenditure - Forecast change by category

Forecast change in average annual operating expenditure (2014-18 vs. 2010-13)

	In dollars million ($m, 2013 prices)							In percentage terms (%)						
	Routine & preventative maintenance	Service interruptions & emergencies	Asset replacement & renewal	Business support	System operations & network support	Other	**Total**	Routine & preventative maintenance	Service interruptions & emergencies	Asset replacement & renewal	Business support	System operations & network support	Other	**Total**
Alpine Energy	+0.3	+0.6	−0.4	+1.2	+1.6	n/a	**+3.0**	+12	+64	−31	+35	+37	n/a	**+24**
Aurora Energy	+1.3	−0.1	−0.1	−3.1	−3.4	n/a	**−5.8**	+36	−2	−5	−91	−86	n/a	**−34**
Buller Electricity	−0.3	+0.1	+0.0	−1.1	−0.3	n/a	**−1.6**	−51	+27	+8	−100	−100	n/a	**−63**
Centralines	+0.1	−0.1	+0.1	−0.1	−0.2	n/a	**−0.2**	+20	−16	+15	−11	−52	n/a	**−5**
Counties Power	−0.3	−0.2	+0.3	+0.0	+0.3	n/a	**+0.1**	−20	−14	+28	+1	+17	n/a	**+1**
Eastland Network	+0.9	−0.1	+0.2	+0.7	+0.4	n/a	**+2.1**	+74	−6	+109	+27	+34	n/a	**+33**
Electra	−0.3	−0.1	+0.5	−1.7	+0.5	n/a	**−1.4**	−15	−4	+61	−86	+34	n/a	**−17**
Electricity Ashburton	−0.4	+0.2	+0.5	+0.0	+1.3	n/a	**+1.6**	−35	+39	+338	+0	+62	n/a	**+24**
Electricity Invercargill	+0.1	+0.1	−0.0	+0.8	+0.4	n/a	**+1.1**	+17	+11	−16	+50	+47	n/a	**+27**
Horizon Energy	−0.2	+0.0	+0.7	+0.3	+0.4	n/a	**+1.2**	−17	+0	+156	+9	+23	n/a	**+16**
Mainpower NZ	−0.2	−0.2	−0.0	+2.2	+1.4	n/a	**+3.1**	−10	−23	−5	+32	+320	n/a	**+29**
Marlborough Lines	−1.3	−0.0	+0.2	−2.1	+0.8	n/a	**−2.6**	−25	−3	+20	−33	+113	n/a	**−18**
Nelson Electricity	−0.0	+0.0	+0.2	+0.0	−0.1	n/a	**+0.1**	−8	+12	+109	+2	−31	n/a	**+4**
Network Tasman	+0.2	+0.1	−0.1	−0.1	+1.0	n/a	**+1.1**	+11	+10	−7	−2	+53	n/a	**+13**
Network Waitaki	−0.0	+0.0	+0.1	+0.3	−0.1	n/a	**+0.3**	−6	+8	+10	+52	−6	n/a	**+8**
Northpower	+1.0	−0.1	−1.2	−1.8	+3.1	n/a	**−0.4**	+56	−8	−37	−31	+194	n/a	**−2**
Orion NZ	+4.6	−2.6	+0.7	+2.9	+4.2	n/a	**+9.4**	+37	−26	+31	+19	+35	n/a	**+18**
OtagoNet	+0.1	−0.2	−0.1	−0.2	+0.9	n/a	**+0.5**	+5	−14	−13	−12	+210	n/a	**+8**
Powerco	+1.5	+0.5	+1.8	−1.6	+5.9	n/a	**+8.1**	+11	+7	+23	−6	+65	n/a	**+13**
Scanpower	+0.4	−0.2	−0.2	−0.3	+0.5	n/a	**+0.2**	+214	−67	−47	−31	+197	n/a	**+11**
The Lines Company	+0.1	+0.4	−0.0	+1.2	−0.1	n/a	**+1.6**	+6	+50	−1	+46	−4	n/a	**+20**
The Power Company	+1.6	+0.6	+0.1	+0.9	−1.5	n/a	**+1.5**	+69	+31	+10	+34	−43	n/a	**+13**
Top Energy	−0.3	−0.3	−0.3	+0.4	+0.9	n/a	**+0.4**	−9	−20	−17	+10	+37	n/a	**+3**
Unison Networks	−0.5	−0.4	+0.6	+2.4	+3.0	n/a	**+5.1**	−11	−12	+42	+16	+60	n/a	**+17**
Vector Lines	−0.1	−5.7	+0.1	−10.7	+30.0	n/a	**+11.8**	−1	−45	+1	−27	+241	n/a	**+13**
Waipa Networks	−0.2	+0.0	+0.0	−0.0	+0.0	n/a	**−0.1**	−15	+5	+12	−0	+4	n/a	**−3**
WEL Networks	+1.9	−0.1	−1.2	+1.1	+2.7	n/a	**+3.3**	+57	−3	−100	+17	+67	n/a	**+18**
Wellington Electricity	+2.0	−0.1	+0.1	+6.1	−5.7	n/a	**+2.4**	+32	−1	+9	+70	−57	n/a	**+8**
Westpower	+0.8	−0.3	−0.3	+0.3	+0.2	n/a	**+0.6**	+22	−39	−50	+19	+13	n/a	**+7**
Industry (excl. Orion NZ)	+8.2	−5.6	+1.7	−4.7	+43.9	n/a	**+37.6**	+10	−11	+4	−3	+57	n/a	**+9**