POWERCO

Submission on

Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper

30 April 2014

Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues

CONTENTS

Default price-quality paths from 1 April 2015
Process and Issues

1 Introduction

1. This is Powerco Limited's submission on the Commerce Commission's consultation paper *Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper*. We comment below under headings that generally follow the scheme of the discussion paper and also provide a summary table of our views on the Commission's proposals and key issues.

2. We appreciate the ongoing discussions with the Commission and the Commission's engagement with the Electricity Networks Association (ENA) working groups.

3. We note that the Commission has set general boundaries for the 2015 re-set in a number of areas and, whilst this provides a degree of certainty, we note that some of the alternatives presented would have significantly different implications for those electricity distribution businesses (EDBs) subject to the default price-quality path (DPP), depending on the options ultimately adopted.

4. Consequently, to assist business planning by EDBs, we would recommend that the Commission publish its emerging views of the actual parameters it is likely to adopt as soon as these become clear.

5. As a general principle, we concur with the Commission's view that there would be little reason to depart from the approaches that were previously applied when resetting the current default price-quality paths, unless new issues become apparent or new information is available.

2 Summary of Powerco's views

6. The following table summarises Powerco's views on the Commission's proposals and key issues for establishing the default price-quality paths from 1 April 2015.

Summary of Powerco's views on the Commission's proposals and key issues

Area	Commission's proposed approach and key issues	Powerco view
Forecast operating expenditure	Retain the approach used for the November 2012 re-set. Key issues include: • whether to determine the initial level using one or more years' data; • what, if any, additional adjustments need to be made.	The most recent year's opex should be used as the base, as this information is the most accurate indicator of the firm's opex needs and should help ensure that prior efficiency gains are passed on to customers. Powerco's analysis of data published as part of information disclosure suggests that the Commission's concerns about possible perverse incentives are not well founded (refer later). Powerco supports the use of estimated 2013/14 opex information, if necessary. We also support refinements to the opex econometric models where there is a clear resulting benefit.
Forecast capital expenditure	The Commission believes that adverse incentives may be associated with relying on distributors' own capex forecasts. The Commission is inviting views on issues associated with: • applying a cap on supplier forecasts, e.g. relative to historical levels; • developing models of certain categories of capex to determine or inform the Commission's forecast.	For the 2015 DPP reset Powerco prefers a cap based on historical capex growth and linked to the accuracy of Asset Management Plan (AMP) forecasts, e.g. EDBs with historical average capex within 10% of their five year forecast would be subject to a 150% cap, those within 10-20% a 130% cap and those outside this a 120% cap. As a more enduring approach, potentially applied for the RCP3 reset, Powerco supports the concept of forecasts being based on age-based survivor modelling, but the success of this approach is dependent on the resolution of a number of key issues, which we describe in our responses to the Commission's questions. Powerco has some experience with age-based survivor modelling and would be happy to meet with the Commission to share information. We support using AMP forecasts to forecast non-network capex. We agree that a model of system growth should not be developed for this re-set because of problems associated with the information disclosure definitions. We recommend that the Commission use the AMP forecasts for customer connections as the AMPs directly identify projects that are known. Modelling would also be difficult because of very mixed trends in customer expenditure between EDBs.
Forecast revenue growth	Retain the existing approach to forecasting revenue growth, updated where required for more recent information. Views are invited on issues with the approach previously used.	Powerco generally supports using population and GDP growth forecasts to forecast volume growth. However, in recent years, improvements in energy efficiency have led to a divergence between these drivers and trends in energy consumption. Consequently, we recommend that an "energy efficiency adjustment factor" be included in the method used to forecast volume growth.

Summary of Powerco's views on the Commission's proposals and key issues

Area	Commission's proposed approach and key issues	Powerco view
Rate(s) of change in price	Approach to determining the long run industry productivity improvement rate is likely to be similar to that used previously. A workshop is scheduled for May.	The Commission has indicated that there has recently been a decline in partial productivity linked to declines in demand, but it expects this trend to be temporary. In our view, the recent declines in demand are driven by technological changes and improvements in energy efficiency that are likely to be secular in nature rather than temporary. We would be concerned if the approach adopted to estimate opex and capex partial productivity rates exactly replicates that used for the 2010-15 regulatory period as, in our view, that method was fundamentally flawed and inconsistent with international practice.
Quality of service incentives	The Commission proposes to move from the current pass/fail regime to a revenue-linked quality incentive scheme. The Electricity Networks Association (ENA) has summarised its findings in a paper provided to the Commission. Views on the ENA paper are invited.	Powerco supports the move to a revenue-based service quality incentive regime. We also support the ENA recommendations that improvements to the regime (for example extending the suite of performance metrics) should be made incrementally following an appropriate level of cost / benefit analysis. Focus should be placed at this reset on implementing the appropriate first steps towards a more enduring performance incentive framework. We support fixed targets for the next regulatory period and basing these targets on 10 years' historical information to more accurately reflect the true underlying relationship between climate and interruption events. Allowance for natural network performance variation should continue by retaining the one standard deviation margin when setting the quality targets. SAIDI and SAIFI should continue to be based on planned and unplanned outages, but planned outages should be weighted 50%. The revenue caps and collars should be initially set symmetrically around the SAIDI and SAIFI targets, such that 1% of maximum allowable revenue is at risk (approximately $2-3m gain or loss for Powerco). For the next regulatory period, the incentive rate ($/SAIDI or SAIFI minute variation from the target) should be determined simply as a constant rate based on one standard deviation from the target, and then further developed for future re-sets via a standardised methodology that could aim to set incentive rates that take account of the value of lost load (VoLL) to different consumers in different interruption scenarios. The incentive rates for different EDBs could also take account of the differing service level variability histories of each EDB. The Commission should investigate simple approaches to normalising data such as "zeroing out" major event days (MEDs), consistent with the practice in the UK and some Australian jurisdictions, and using a more straightforward approach to identify MEDs such as X times (say 7 or 8 times) the average daily value. We support the proposed work to further develop the customer service measures and options for the disaggregation of the SAIDI and SAIFI measures.

Summary of Powerco's views on the Commission's proposals and key issues

Area	Commission's proposed approach and key issues	Powerco view
Enhanced incentives for performance improvements	Two further enhancements proposed: • incentives for distributors to control expenditure during a regulatory period; • incentives for energy efficiency, demand-side management and the reduction of losses.	Powerco supports, in principle, the introduction of an incremental rolling incentive scheme (IRIS), provided its application to the DPP is asymmetric. The ENA recommendations for near term measures to promote energy efficiency, demand-side management and efficient loss reduction are pragmatic. We support the introduction of a "D" factor to the DPP to compensate for the effect of lost revenue due to energy efficiency and related programmes. We detail some real world examples of instances where clarification of whether or not assets resulting from expenditure on new technologies may come within the statutory definition of "electricity lines services" would be helpful.
Treatment of uncertainty and catastrophic risk	The Commission expects to adopt a similar approach to that used for the November 2012 re-set. Views are invited on issues relating to recovering pass-through and recoverable costs. The Commission believes its existing approaches to the treatment of catastrophic risk are consistent with distributors being appropriately compensated for any potential net costs or lower than forecast revenues resulting from a catastrophic event. Views are invited.	With respect to the risk of inadvertently breaching the DPP due to incorrect estimates of pass-through and recoverable costs or subsequent rebates and refunds of rates and levies, we recommend an annual wash-up mechanism applying the formula: $\text{adj. to } ANR_t = (ANR_{t-2} - NR_{t-2}) \times (1 + \text{time value of money})^2$ Penalties could be applied if variances were excessive. We believe that the volume risk associated with pass-through and recoverable costs is not material and can be managed. As noted in previous submissions, in our view the Commission has moved away from the position it adopted before the Christchurch earthquakes, which was that EDBs would not be compensated for catastrophic risk *ex ante*, but would be fully compensated *ex post*. We also note that, In reality, diversification can be impracticable for lines businesses that necessarily have all their lines in a particular geographic region.
Outstanding claw-back amounts	The Commission proposes to spread any outstanding claw-back amounts allowed under s.54K(3) of the Commerce Act equally through the next regulatory period. Views invited on this approach and the method used to calculate outstanding amounts.	We agree with the proposed approach.

3 Approach to setting starting prices

3.1 Overall approach

7. The Commission states that it will assess the options of either rolling over the prices that previously applied at the end RCP1, or adjusting starting prices based on the current and forecast future profitability of each distributor, based on the materiality of the differences between them. Powerco supports this approach, but notes that the differences are very likely to be material and that, therefore, prices are very likely to be reset based on current and forecast future profitability.

3.2 Forecasting operating expenditure

8. The Commission is proposing to forecast operating expenditure using the approach it used for the November 2012 reset. The key issues the Commission has sought feedback on are:

- whether to determine the initial level of opex using one or more years' data; and
- what, if any, additional adjustments need to be made for operating expenditure that is not already captured by the Commission's approach.

3.2.1 Determining the opex base expenditure

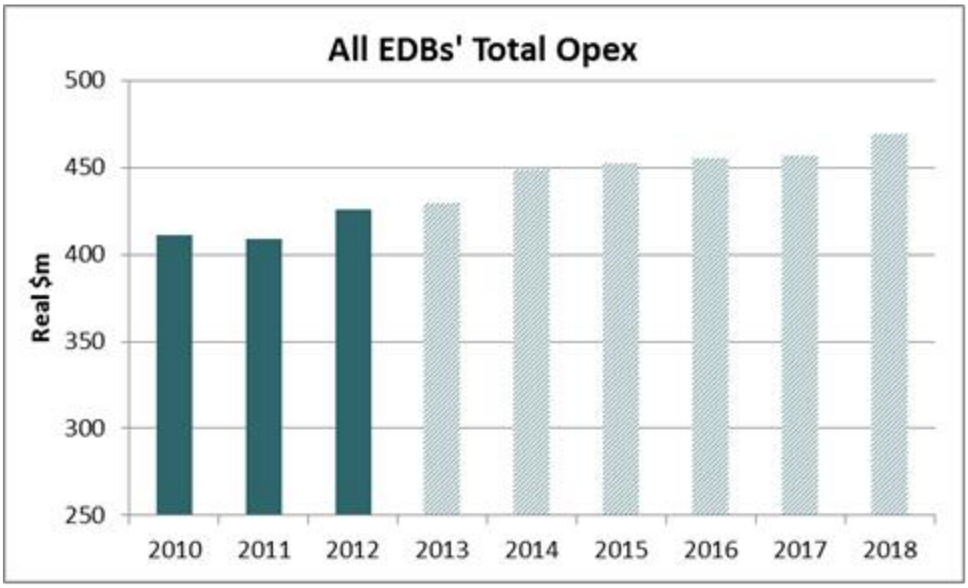
9. In the November 2012 reset the Commission used a single base year of the latest opex expenditure to set the initial level of expenditure. Powerco believes this approach is preferable for establishing the DPP in 2015, because it uses the latest available information, which is likely to be the most accurate indicator of the firm's current opex needs. In the issues paper the Commission raises as a concern the possibility that 2013/14 expenditure may not represent distributors' future efficient operating expenditure and proposes three options for consideration, viz.:

- using 2013/14 data only, which would represent the most recently available, single year of operating expenditure at the time of the final decision;
- using 2012/13 data only; or
- using an average of a longer time series, such as from 2009/10 to 2013/14.

10. Powerco's preference is to use 2013/14 data only, because using the most recently available information should help ensure that efficiency gains achieved prior to the start of the regulatory period are passed on to consumers. We also do not believe there is a compelling argument not to use data from this year.

11. The Commission has two concerns about using 2013/14 as the base year. First, it suggests that EDBs may have presumed that the Commission would use a single year and would therefore have an incentive to bring expenditure forward to FY14. Powerco does not believe this is likely to be the case in practice, as the Commission has never committed to using a single base year for the reset and has a history of varying its approaches.

12. Our view is supported by the fact that EDBs have not forecast that FY14 operating expenditures will be in any way out of the ordinary, as demonstrated by the following graph taken from the data collected by the Commission's summary and analysis of Asset Management Plan (AMP) forecasts.



Source: Commerce Commission electricity information disclosure summary and analysis, March 2013

Note that while FY13 is shown as a forecast, numbers would have been near final at the time this information was provided.

13. Second, the Commission states that using a single year risks it being an atypical year. Powerco is not aware of any reason for 2014 to be atypical. The graph above and our knowledge suggest that the prior year (2013) was an unusually low expenditure year, due to the fine calm weather that occurred that year and the consequent low number of major event days. In our view, the atypical nature of 2013 further supports the use of a 2014 base and excluding 2013.

3.2.2 Provision of opex data

14. The Commission is seeking feedback on how it should collect 2013/14 opex information (if it needs to use it). The Commission's preferred approach is to use estimates, with EDBs having the opportunity to provide actual data before the draft decision (which the Commission states it needs to make by 23 May 2014). Powerco supports this approach.

3.2.3 Opex econometric model

15. In the November 2012 reset the Commission used an econometric model which linked line length growth and ICP growth to opex growth. Powerco has been part of the ENA working group on DPP forecasting methods and, based on this experience, we believe there is merit in refining these models. Frontier Economics provided a number of options that are worth considering.

3.2.4 Forecasting line length growth – correcting disclosure data

16. The process to forecast operating expenditure proposed by the Commission includes an estimation of the effect of changes in scale. The effectiveness of the econometric model relies on the accuracy of the two proxies for network scale proposed: network length and the number of users.

17. Powerco's network is made up of fifteen discrete legacy networks that have been amalgamated over time. This diversity of networks has created ongoing data and systems integration and improvement challenges for Powerco, which extend to the reporting of line length. Powerco's historical line length reported in information disclosures is indicative of the various improvements to data over time.

18. Powerco has invested heavily in systems and data refinement including, from 2011 to 2013, the development of a bespoke asset modelling tool to view and query information from a variety of sources. The development of this tool has allowed Powerco to define more accurately service lines and service line lengths on Powerco's networks and exclude them from the calculation of total circuit length as required by the 2013 disclosure definitions for line length. Powerco continues to revisit line length data held in its GIS and refine its asset modelling tool.

19. The historical line length growth from 2004 to 2013 is shown in the table below. The annual growth rates range from -6.36% to 7.51% per year. The constant average growth rate indicated by disclosed information from 2004 to 2013 is 1.64% per year.

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Line Length (km)	24,940	26,812	27,090	27,255	27,361	29,274	30,035	29,920	30,841	28,879
Growth Rate		7.51%	1.04%	0.61%	0.39%	6.99%	2.60%	-0.38%	3.08%	-6.36%

20. Given the issues with the year by year data above and the possibility that this will affect the results in any econometric model, Powerco suggests we provide the Commission with corrected data to be used to help develop the draft price reset decision.

3.2.5 Opex input costs

21. The Commission proposes to use the same approach to escalating opex as used for the November 2012 re-set. Powerco supports the recommendations of the ENA DPP Forecasting Working Group reports that propose the use of a number of more accurate input escalators.

3.3 Forecasting capital expenditure

3.3.1 Network capex forecast

22. The Commission states that it is developing its approach to forecasting capital expenditure for the forthcoming re-set and is evaluating two options, viz.:

- allowing distributors their own capex forecasts, subject to a limit which may or may not be the 120% value used for gas pipeline businesses;
- developing low cost models that could be used to forecast capex independently.

23. The Commission noted that it was investigating alternative forecasting methods because of the adverse incentive for distributors to adopt low risk assumptions or otherwise inflate their forecasts. The Commission has invited comment on alternative modelling approaches, while noting that its priority for the coming reset is a model for replacement and renewal expenditure. With respect to this category of expenditure, the Commission is attracted to the concept of an age-based survivor model.

3.3.2 Age-based survivor model

24. The Commission notes that the robustness of this type of modelling is dependent on resolving a number of questions on key issues. We set out our initial responses to the questions posed by the Commission in Appendix A.

25. Powerco has built up a degree of experience with this type of forecasting and would be happy to meet with the Commission to share information. However, if the Commission decides to use an age-based survivor approach to modelling replacement and renewal capex, we believe it should also use this approach to inform replacement and renewal

opex. This is because the two categories are related, such that a step-up in renewal capex would likely be associated with a step-up in renewal opex.

3.3.3 Powerco's preference – a cap based on historical growth and linked to AMP accuracy

26. The Commission notes that capex is inherently volatile year on year, although, over the regulatory period, the degree of variability is less. Powerco agrees and believes that these characteristics support the use of a simple top-down approach to forecasting capex.

27. A linear trend based on historical expenditure may give an unrepresentative result and seems unnecessary given that suppliers have provided more accurate analysis and forecasts in their AMPs. Powerco therefore supports using the AMP forecast as a starting point. We recognise the Commission's concerns that using EDBs' forecasts may create an incentive to adopt low risk assumptions. While we have not done this for our AMP, we have no knowledge of other EDBs approaches, so cannot rule out the need for a cap (although we doubt other EDBs have inflated their forecasts).

3.3.4 The size of the cap could be based on historical expenditure growth

28. Setting a cap is inherently difficult. One possible approach is to base the cap on historical expenditure trends. The table opposite compares the growth in EDB capex from a single five year period (2004-2008) to another (2009-2013). This helps reduce the volatility risk inherent in year to year changes.

29. The figures compared are nominal. Therefore an adjustment for input cost increases needs to be made to produce a fair comparison. Wellington Electricity has also been excluded as historical information was not available for them. The non-exempt EDBs are bolded.

30. The (unweighted) average change is a 41% increase over five years.

Percentage increase in total capex from 2004-2008 to 2009-2013

Westpower	-30%
Network Tasman	-28%
Eastland Network	-28%
Buller Electricity	-23%
Scanpower	-16%
Network Waitaki	-5%
The Lines Company	0%
Vector	5%
Aurora Energy	20%
Counties Power	25%
Unison Networks	25%
Waipa Networks	26%
Electra	36%
Orion New Zealand	40%
Marlborough Lines	45%
The Power Company	46%
WEL Networks	47%
Electricity Invercargill	52%
Horizon Energy Distribution	61%
MainPower New Zealand	67%
OtagoNet Joint Venture	68%
Electricity Ashburton	71%
Powerco	77%
Centralines	84%
Alpine Energy	89%
Northpower	95%
Nelson Electricity	99%
Top Energy	187%

Source: EDB annual information disclosures, 2004-2013

3.3.5 The size of the cap could be based on the historical accuracy of AMP forecasts

31. A second possible approach would be to adjust the size of the cap based on each EDB's historical ability to achieve its AMP forecast. This adjustment could only be applied to forecast network capex, as historical non-network capex forecasts are not available. We believe the most appropriate information to use for this purpose would be the 2009 AMP forecast, as this would enable five years' actual expenditure forecasts to be used, which matches the regulatory period. The five year period would also moderate year to year volatility.

32. The table below shows the percentage by which the five year 2009 AMP network forecasts were below or above actual expenditure. The non-exempt EDBs are bolded. The average percentage difference was -5% (un-weighted by the size of EDB).

Difference	Percentage network capex (2009-2013) is under or over 2009 AMP forecast
Scanpower Limited	-40%
Network Waitaki Limited	-38%
The Lines Company	-33%
Nelson Electricity Limited	-25%
The Power Company	-24%
Counties Power	-24%
Alpine Energy Limited	-18%
Westpower Limited	-16%
Electricity Invercargill	-14%
Orion New Zealand	-13%
Mainpower New Zealand	-12%
Eastland Network	-12%
Northpower Limited	-11%
Centralines Limited	-10%
OtagoNet Joint Venture	-5%
Wellington Electricity Limited	0%
Network Tasman Limited	1%
Electra Limited	2%
Powerco Limited	3%
Buller Electricity	3%
WEL Networks	6%
Aurora Energy	13%
Marlborough Lines Limited	16%
Top Energy Limited	18%
Horizon Energy Distribution	21%
Vector Lines Limited	23%
Waipa Networks Limited	25%
Unison Networks	29%
Electricity Ashburton	32%

Source: EDB annual information disclosures (2009-2013) and 2009 AMPs

33. A possible approach would be to allow EDBs with actual historical average capex within 10% of their five year forecast a 150% cap, those within 10-20% of their forecasts a 130% cap and EDBs outside this a 120% cap.

3.3.6 Non-network capex forecast

34. EDBs' non-network expenditure is even more volatile than network expenditure. This is partly because it is much lower and partly because occasional, and one-off, large projects, such as replacing an asset management system, can distort the expenditure trends.

35. Powerco supports using EDBs' AMP forecasts to forecast non-network capex (with no cap). Baseline non-network expenditure should be fairly constant and actual expenditure is unlikely to vary significantly from forecasts. The AMPs also factor in specific projects more accurately than the Commission could predict.

3.3.7 Modelling system growth capex

36. The Commission states that there are a number of issues that would need to be resolved before a system growth model could be used in New Zealand. At this stage, it considers that it is unlikely it will develop a detailed model for system growth at the forthcoming re-set.

37. The Commission is seeking feedback on whether or not we consider it has the correct prioritisation. Powerco supports not developing a model of system growth for this re-set given the problems associated with the information disclosure definitions.

3.3.8 Modelling customer connections

38. The Commission notes that the third most significant category of capex is customer connections. While this is correct, the proportion becomes much less for some EDBs when customer contributions are netted off the capex total.

39. The table below shows the percentage of customer contributions forecast in AMPs as part of the customer connection capex category. (Figures are the five year average of the 2013-18 AMP forecasts.) Four EDBs have contributions of over 75% and eight over 50%. For Powerco, this reduces the percentage of customer connections capex from 14% of total capex to 3% of total capex.

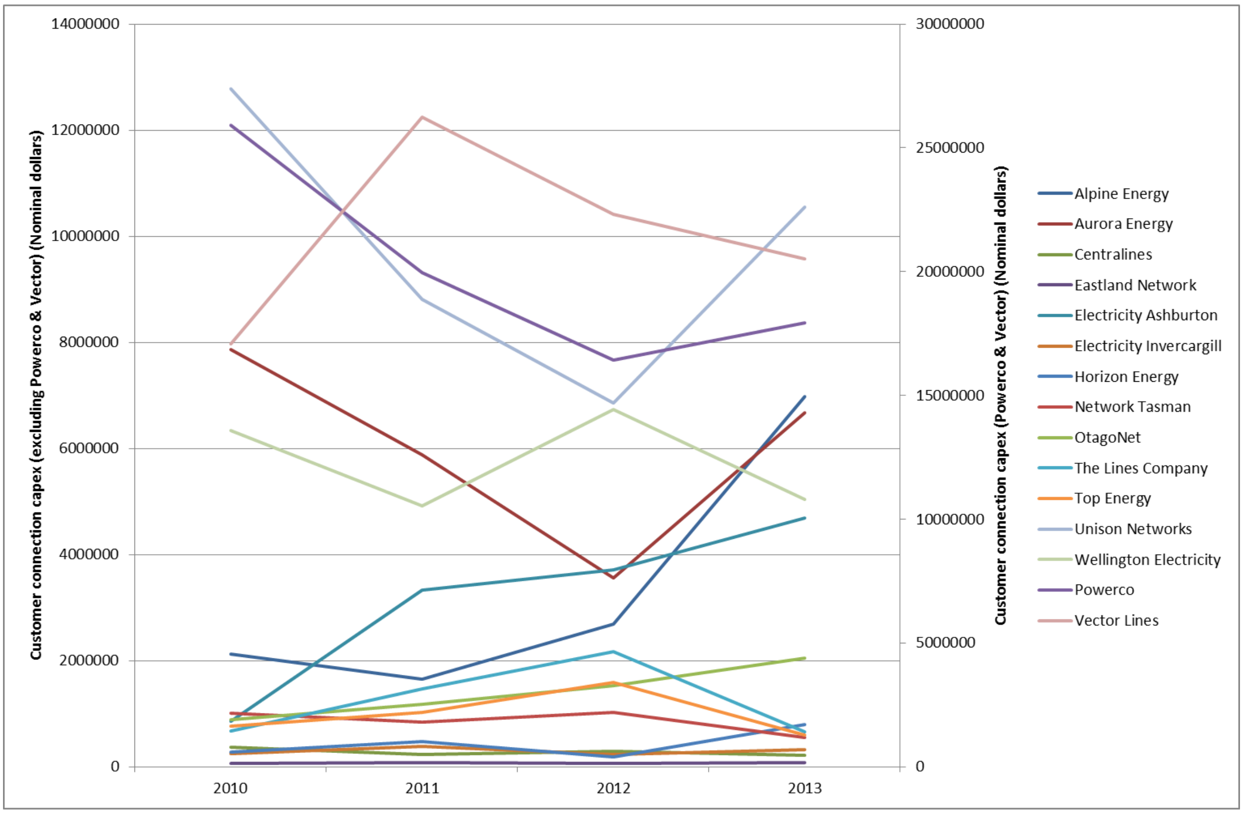
Non-exempt Company	Percentage
Horizon Energy	-83%
Aurora Energy	-76%
Vector Lines	-76%
Powerco	-76%
Eastland Network	-66%
OtagoNet	-65%
Unison Networks	-58%
Wellington Electricity	-53%
The Lines Company	-20%
Electricity Ashburton	-19%
Alpine Energy	-19%
Network Tasman	-4%
Centralines	0%
Electricity Invercargill	0%
Top Energy	0%
Nelson Electricity	0%

Source: Commerce Commission electricity information disclosure summary and analysis, March 2013

40. The Commission states that this type of expenditure is more predictable than other categories and historically appears to be more consistent. However, Powerco's experience is that this is actually the least predictable expenditure category, as it is completely dependent on customer requests, some of which can be very lumpy. We have no ability to predict these requests, especially five years into the future. It is also

very difficult to defer customer connections capex, as customers often need the work done promptly.

41. While some of the expenditure change may have a moderate correlation with GDP and population growth, generally projects are more related to a range of other factors. This is shown by the graph below which illustrates a varied mix of trends in customer connection expenditure. It also shows that the trends for many EDBs are not smooth (as suggested by figure B4 in the issues paper).



Source: Commerce Commission electricity information disclosure summary and analysis, March 2013

42. Powerco recommends that the Commission use the AMP forecast for this category as the AMP directly identifies projects that are known.

3.3.9 Other categories of capex

43. The Commission proposes to take a simple approach to modelling the remaining categories of capex (system growth, asset relocations and reliability, safety and environment). Powerco's preference would be to use a standard cap for these categories as previously discussed.

3.4 Forecast revenue growth

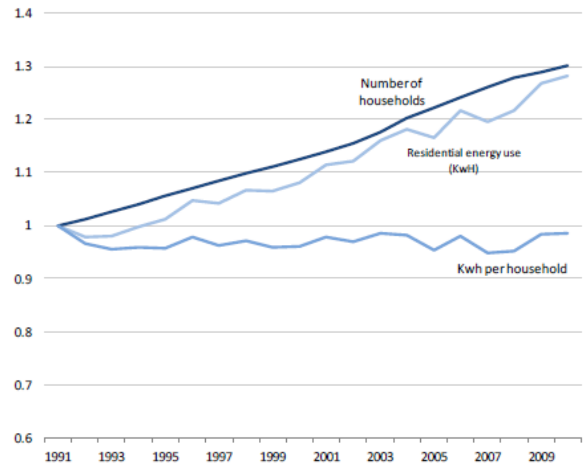
44. The Commission proposes to retain its existing approach to forecast revenue growth, updated for more recent information, and has invited views on any concerns about this approach.

45. Powerco generally supports using population and GDP growth forecasts to forecast volume growth. We have, however, noticed that improved energy efficiency has been

affecting volume growth in recent years and therefore recommend that an "energy efficiency adjustment factor" be included in the method used to forecast volume growth.

46. In the 2013 DPP starting price adjustment the Commission assumed that the change in electricity use per residential user was 0%. This fed into the constant price revenue growth forecast. The assumption was based on the trend in energy use per household since 1991 using Ministry of Business, Innovation and Employment (MoBIE) data (see below).

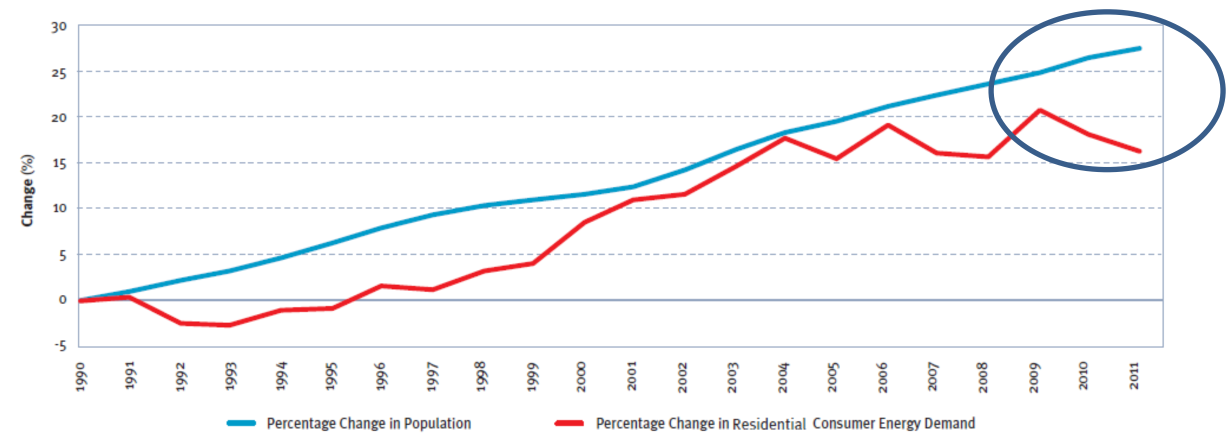
Chart H.5 Trends in the number of households, residential energy use and energy use per household (1991=1)



Source: Ministry of Business, Innovation and Employment

47. In September 2012 MoBIE published a report and data on changes in energy use[1]. When data for 2010 and 2011 are added a different trend emerges, with energy demand diverging from population growth (see below).

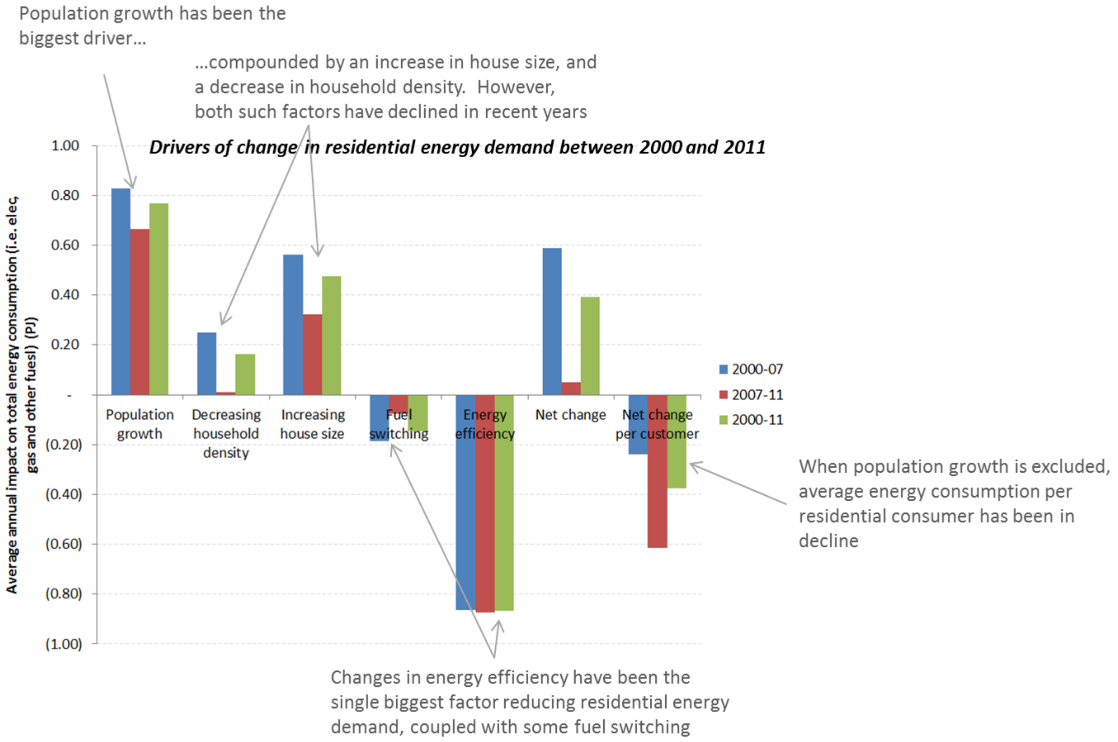
Figure 4: Change in Population and Residential Consumer Energy Demand



Source: Ministry of Business, Innovation and Employment

[1] http://www.med.govt.nz/sectors-industries/energy/energy-modelling/publications/changes-in-energy-use

48. The drivers of changes in residential use between 2000 and 2011 are shown in the graph below.



Source: Ministry of Business, Innovation and Employment

49. Hence, when population growth is excluded, the average energy consumption per residential consumer has recently been declining, mainly due to improved energy efficiency. Trends of this sort are now apparent in most developed economies.

50. Other factors, such as increases in distributed generation and the uptake of electric vehicles may also affect energy intensity. However, it is unlikely these will have a significant effect between 2015 and 2020.

4. Allowable rates of change in price

51. We note that, if starting prices are based on the current and projected profitability of suppliers, the rate of change will not affect the amount of revenue recovered over a regulatory period, because the Commission uses the rate of change when setting expected revenues equal to expected costs over the regulatory period.

52. However, the rate of change will affect the rate at which revenue is recovered during the regulatory period, such that a higher X-factor will result in an overall lower rate of change, i.e. CPI-X and hence a lower rate of increase in revenue.

53. The Commission has indicated that there has recently been a decline in partial productivity linked to declines to demand, but it expects this trend to be temporary. In our view, the recent declines in demand are driven by technological changes and improvements in energy efficiency that are likely to be secular in nature rather than

temporary. In recent years, most developed countries have observed that energy consumption has substantially decoupled from GDP growth and is no longer increasing. In our view, New Zealand's experience is likely to be similar to that encountered overseas.

54. The Commission has also asked Economic Insights to estimate the operating and capital expenditure partial productivity rates using the same approach that was used for the 2010-15 regulatory period. We will await the report from Economic Insights before commenting further and look forward to the workshop being held on 6 May. However, we would be concerned if the approach adopted exactly replicates that used for the 2010-15 regulatory period as in our view (supported by others) that method was fundamentally flawed and inconsistent with international practice.

5. Service quality incentives

55. For the next regulatory control period (RCP2), the Commission has proposed a move away from a "pass/fail" quality regime and has sought views on the detailed application of the key attributes of a possible revenue-based incentive regime. Powerco supports the Commission's proposal to move to a revenue-based incentive regime. Such a change would be consistent with the recommendations of ENA's Quality of Supply and Incentives (QoSI) working group, contained in the group's report *Pathway to Quality*.

56. We also support the discussion on quality incentives in the ENA submission. In particular, we note that quality in this context refers to the price quality trade-off sought by consumers and not "everything outside of the price" as stated by the Commission. We would further emphasise that the transition to a superior (and potentially extended) quality regime will take time and that, as noted in the QoSI report, this DPP reset should be seen as an opportunity to take the first step on this journey.

57. Specific matters relating to the practical development of the new regime are:

- how the targets, caps, collars and incentive rates should be established;
- how the data should be normalised to identify the underlying performance of the network; and
- how the regime should be refined and improved in the future.

58. We address these points below.

5.1 Establishing the targets, caps and incentive rates

59. There are a number of options available for establishing the targets, caps, collars and incentive rates that might apply under a revenue-linked service quality incentive regime. These include the use of rolling or fixed targets, continuing to base the targets on five years' historical data or using ten years' data as in the UK, setting the caps and collars based on revenue exposure or as a function of the SAIDI and SAIFI distribution for each EDB and how to provide an appropriate allowance for natural variation when setting the targets. Powerco's view on these issues is that the Commission needs to provide sufficient time to enable measured incremental development of an improved regime while also implementing appropriate first steps as part of this re-set.

60. The following are the initial steps that Powerco believes should be implemented as part of the next re-set:

5.1.1 Fixed targets should be established for the next regulatory period.

61. Fixed targets create certainty for both consumers and EDBs and establish a reliable framework against which to plan and operate a network over the regulatory period. By contrast, using rolling targets creates unnecessary uncertainty and complication, as illustrated by the requirement for banking mechanisms in the Australian regime. This sort of complication can be avoided by setting simple but effective fixed targets that are reset at the start of each RCP.

5.1.2 The targets should be based on the longest established time series of historical information with 10 years preferred.

62. Because service quality performance is dominated by weather events, using a long data series will more accurately reflect the true underlying relationship between climate and interruption events, rather than the impact of variable and transient weather events. We note that the UK uses ten years of high voltage data against which to assess the performance of network companies. We would endorse this approach, as we believe a ten year data series is generally sufficient to reveal the underlying performance of a network, while a five year series may still be subject to distortions due to particular major weather events. For long life, high voltage, network assets it is important that the underlying performance of those assets be used to determine the quality metrics used to establish the incentive regime.

5.1.3 Allowance for the natural variation in the performance of the network should continue to be recognised by retaining the one standard deviation margin when setting the quality targets.

63. Retaining the current one standard deviation margin when setting the quality targets, in order to reflect the natural variation in network performance, is essential to the effective operation of the incentive regime. Investment levels and operational processes have evolved in response to the current targets. Any significant move away from setting the initial targets based on performance of one standard deviation from the historical mean would represent a substantial regulatory shock for EDBs that we do not believe would be consistent with the objectives of Part 4 of the Commerce Act or the “no material deterioration” objective of the DPP regime.

5.1.4 SAIDI and SAIFI should continue to be based on planned and unplanned outages, but planned outages should be weighted 50%.

64. As noted in the QoSI report, the current equal weighting of planned and unplanned outages can create a perverse incentive for EDBs to restrict planned work that would benefit end consumers in order to stay within regulated quality service targets. In order to moderate this perverse incentive we recommend that the Commission seriously consider weighting planned outages by 50%, which would be consistent with current UK practice. As well as reducing the perverse incentive to limit planned interruptions, which are critical to the long-term provision of services that customers value by enabling network maintenance to be undertaken, the lower weighting would more accurately reflect the typically lower cost of planned outages and the greater concern that customers have about unplanned interruptions relative to those that have been scheduled in advance. The lower cost associated with planned outages is due to the fact that planned outages are generally well notified and communicated to customers, and this enables the customers to take action to limit the negative effects of these outages.

5.1.5 Revenue caps and collars should be initially set symmetrically around the SAIDI and SAIFI targets, such that 1% of maximum allowable revenue is at risk, with a constant incentive rate ($/SAIDI or SAIFI minute variation from the target) based on one standard deviation from the target, and then further developed via a standardised methodology that can be applied across EDBs.

65. In our view, a reasonable initial step would be to set the revenue caps and collars symmetrically around the SAIDI and SAIFI targets, such that 1% of maximum allowable revenue is at risk (approximately $2-3m gain or loss for Powerco). For the next regulatory period, the incentive rate ($/SAIDI or SAIFI minute variation from the target) should be determined simply as a constant rate based on one standard deviation from the target incentive rate.

66. The Commission should then follow a measured process to develop a standardised methodology that can be applied to future re-sets, with the aim of setting consistent incentives to improve quality outcomes for consumers across the country. Ideally, over the long term, there should be an alignment between the incentive rates and the value of lost load (VoLL) to different groups of consumers in different interruption scenarios. The incentive rates for different EDBs could also take account of the differing service level variability histories of each EDB. However, we do not consider this degree of sophistication is practicable for the coming re-set.

5.2 Normalisation of data

67. Extreme event normalisation is essential to moderate the effect of events (such as major storms and earthquakes) that are outside the control of EDBs. The QoSI working group has identified a number of issues associated with alternative approaches to data normalisation and scoped out further work that should be done. We agree with this assessment and the further work proposed, but we also propose that, for this re-set, the Commission should investigate simple approaches such as "zeroing out" major event days (MEDs), consistent with the practice in the UK and some Australian jurisdictions, and using a more straightforward approach to identify MEDs such as X times (say 7 or 8 times) the average daily value.

5.3 Future development of a more sophisticated regime over time

68. Powerco supports the further refinement of the regime for future regulatory periods, including formal engagement with different consumer representatives to establish value preferences, and notes that this exercise will comprise the major part of the next phase of work for the QoSI working group.

69. As noted by the issues paper, this work will include the possible further development of the customer service measures and options for the disaggregation of the SAIDI and SAIFI measures. We also note that information disclosure could be used to develop datasets ahead of the possible introduction of any new measures.

6. Other incentives

6.1 Incentives for distributors to control expenditure during a regulatory period

70. The Commission notes that it is currently considering an amendment to the input methodologies to implement an incremental rolling incentive scheme (IRIS) for default price-quality paths. Powerco has previously indicated its support, in principle, for the

introduction of an IRIS, provided its application to the DPP is asymmetric (i.e. does not penalise increased expenditure which may be justified by the individual circumstances of particular EDBs.) We look forward to the opportunity to comment on the draft amendments to the input methodologies when they are published.

6.2 Incentives for energy efficiency, demand side management and the reduction of losses

71. The Commission has invited comment on some of the recommendations proposed by the ENA as possible means of promoting energy efficiency, demand side management and efficient loss reduction. The ENA recommendations for the near term measures have focused on avoiding the economic disincentives on distributors to pursue initiatives in these areas.

72. Powerco considers that the ENA recommendations are pragmatic, having regard to the time available, current knowledge and commercial materiality of the possible initiatives. We comment below on the specific matters raised in section 5.11 of the issues paper.

6.2.1 Compensation for revenue forgone ("D factor")

73. Powerco supports the principle of compensation for the commercial effect of a material loss of demand arising from a successful energy efficiency programme that is reasonably expected to be in the long term interests of the consumers. Investors will need assurance that, in the event of a successful programme materially reducing volumes in the network (and hence volume based revenues) a transparent compensation mechanism will be applied. Consequently, we recommend that the Commission incorporate a "D" factor into the DPP.

74. However, we recognise that any mechanism would need to be applied pragmatically to reflect:

- the need for administration costs incurred by the Commission and the industry to be kept low in order to preserve the benefits of some programmes and encourage innovation; and
- the fact that new programmes would generally take some years to gain consumer acceptance, and that any programmes adopted would be likely to have a moderate (and uncertain) effect on consumption in the immediate future.

6.2.2 Investments that may fall outside the definition of "electricity lines services"

75. Assets used for the management of demand side services today are either embedded within the network or explicitly allowed for in the input methodologies (e.g. ripple receivers) and have a primary function of supporting the conveyance of electricity by line. Consequently, these assets clearly contribute to the provision of electricity lines services and can be included in EDBs' regulatory asset bases.

76. As technology changes there is an emerging set of activities that EDBs could facilitate, which could require investment in different sorts of equipment, or the leasing or subsidising of particular assets. EDBs might also become more heavily involved in information provision and service promotion programmes. These new technologies are often located "behind the meter" (i.e. within or on consumers' premises and so detached from the lines supply) and frequently provide other services to consumers (that may be considered by the consumers to be more important than the support they provide to lines function services). Both of these characteristics make it less clear that the assets concerned may be classed as assets required to provide electricity lines services.

77. The table below provides real world examples of instances in which clarification would be helpful.

Equipment/ expenditure category	Contribution to network efficiency	Other Service	Comment
In home displays, applications and feedback services, plus educational and promotional campaigns	Reduce network peaks	Conceivable that portals could also support non lines function services	May involve opex that would benefit from an input methodologies that would address demand-side management incentives
In house appliance controllers such as “smart” thermostats (and supporting sensors, communications equipment, etc.)	Reduce network peaks	May provide managed heating, control in home power use or other services; overseas providers are combining these with non-power related services (e.g. security devices)	Possible EDB owned assets
Insulation and heating solutions, including insulation covered lighting, and other heating types that reduce peaks (including gas and radiant heating)	Reduce network peaks	Improved thermal insulation reduces peak use (but consumers motivated by warmer homes, greater comfort and improved health)	Possible EDB owned assets
Smart (PV) inverters allowing management of VARs on networks or the management of energy exports to the grid	Network quality	Supports consumer use of photovoltaic generation	Possible EDB owned assets
Home generation or other fuel substitution (e.g. photovoltaics, where summer peaks occur)	Reduce network peaks	Supports consumer use of home generation	Possible EDB owned assets
Energy storage	Reduce network peaks	Provide consumers with increased ability to use photovoltaic generation	Possible EDB owned assets

7. Uncertainty associated with pass-through and recoverable costs

78. Currently, EDBs run the risk of inadvertently breaching the price-quality path because:

- the estimated value of pass-through and recoverable costs may turn out to be less than the actual value; and
- rebates and refunds of rates and levies reduce actual pass-through and recoverable costs but may have been unknown at the time prices were set.

79. Powerco currently allows for this risk by setting its target revenue a little below the regulated maximum.

80. The Commission's decision on the default price-quality paths for gas pipeline businesses allows suppliers to deduct only pass-through and recoverable costs that are known prior to the start of the assessment period. Pass-through and recoverable costs that become known after the supplier sets its prices may be claimed in a future period adjusted for the time value of money.

81. Along with other ENA members, Powerco has considered the gas pipeline option and observed that, while it addresses the forecasting risk, it has a number of problems, including:

- the need to develop a practical definition of "ascertainable";
- possible inconsistencies with information disclosures due to the lagged nature of the cost recovery, relative to the costs incurred;
- possible transitional issues between regulatory periods, and regulatory mechanisms (in particular DPP to CPP);
- the practical impact of this approach is that one year's worth of non-ascertainable costs will never be recovered as there will always be an amount of revenue which has not been recovered despite the costs being incurred (and paid for) by the EDB.

7.1 Powerco's preference is for a wash-up mechanism

82. In our view, the annual wash-up mechanism proposed in the ENA submission would be a superior solution. As described in the ENA submission, the wash-up mechanism could be implemented as follows:

- DPP compliance statements would continue to set out the values for allowable notional revenue (ANR) and notional revenue (NR) for the most recent assessment period, and demonstrate how they are calculated;
- the difference between ANR and NR would be stated, but the *ex post* compliance test would not result in a "pass/fail";
- any over- or under-recovery would be included in the price path in a subsequent year, adjusted for the time value of money.

83. The adjustment would have to be made at least two years after the over/under-charge occurred, since it would not be able to be determined in time for prices to be set for the immediately subsequent year. The formula applied would be:

$$\textit{adjustment to } ANR_t = (ANR_{t-2} - NR_{t-2}) \times (1 + \textit{time value of money})^2$$

84. The wash-up could apply to a range of unintentional causes of price-path breaches, including inadvertent mis-forecasting of recoverable and pass-through costs and also, for example, the unintended consequences of price restructuring.

85. The wash-ups would necessarily overlap DPP/CPP regulatory periods such that a difference between ANR and NR in the last year of a regulatory period would affect ANR in the next regulatory period.

86. Incentives may be necessary to encourage forecasts made at the time prices are set to be as accurate as possible, i.e. variances that exceed a certain threshold could be penalised. The penalties should apply only where NR exceeds ANR, as EDBs should be permitted to price below their price paths without penalty. Possible penalties could include:

- adjusting the time value of money (e.g. multiplying it by 2) if NR exceeds ANR by more than 1%;
- an investigation by the Commission if variances exceed 5% of ANR.

87. Wash-ups could be capped if an EDB systematically charges prices which are materially less than the price path permits. The cap would avoid potentially large price adjustments later in a regulatory period. Without the cap, wash-ups could provide a mechanism to restore previous under recoveries. We accept that this would less appropriate if under-recoveries reflected decisions which were not related to price setting uncertainty.

7.2 Volume risk on pass-through and recoverable costs

88. The Commission has invited comment on the volume risk associated with pass-through and recoverable costs. These costs represent about 30 per cent of Powerco's charges and so are material in that sense. However, in practice, we have found that the variability due to volume specifically with respect to pass-through and recoverable costs has not generally been material and has been manageable, provided that no extraordinary events have occurred that would affect volumes (such as natural disasters).

89. EDBs can manage an element of volume risk by modifying the way they charge to recover these costs and by improving the accuracy of their forecasting. While we would support a more detailed review of this issue (over the medium term), from Powerco's perspective it is not a priority for the forthcoming re-set, as the current arrangements are satisfactory in the absence of significant unforeseen circumstances (outside our control).

7.3 Risk associated with catastrophic events

90. This issue has been well canvassed by the submissions on Orion's price-quality path. We will not repeat these here, except to note that the Commission has moved away from the position it adopted before the Christchurch earthquakes, which was that EDBs would not be compensated for catastrophic risk *ex ante*, but would be fully compensated *ex post*.

91. We do, however, wish to comment on the Commission's statement in the issues paper that investor diversification minimises the impact of risks resulting from catastrophic events. In reality, diversification can be impracticable for lines businesses that necessarily have all their lines in a particular geographic region.

8. Outstanding claw-back amounts

92. The issues paper proposes that outstanding claw-back amounts that are unable to be recovered in the current regulatory period should be smoothed over the full subsequent regulatory period to limit the effect on prices and that the cost of debt should be applied to the smoothing calculation. Powerco believes this approach is appropriate.

9. Treatment of assets purchased from Transpower New Zealand

93. The Commission is seeking to clarify the regulatory treatment of assets purchased from Transpower. Powerco supports further clarification of the regulatory provisions in this area. Powerco has purchased assets from Transpower in past years and is forecasting future purchases of spur assets from Transpower to support Powerco's network.

94. The key areas the Commission is seeking feedback on are:

- the impact on quality service standards; and
- the impact of asset transfers on operating and capital expenditure.

9.1 The impact on quality service standards

95. The Commission recognises that, after assets are transferred to a distributor from Transpower, the underlying reliability performance of a distributor's network may experience a step change (which will often be negative). The Commission has indicated that it is considering including an adjustment mechanism in the quality standards used to set quality.

96. Powerco supports the inclusion of an adjustment mechanism to recognise the effect on quality associated with the transfer of assets from Transpower. The Commission suggests the adjustment could reference the spur asset's historical reliability. Powerco supports this approach.

97. Powerco's due diligence process for future purchases has highlighted that some spur assets it has considered purchasing have exhibited steadily deteriorating reliability. If the particular assets concerned were purchased, recalculating the quality limit may add, for example, three minutes to Powerco's SAIDI limit, but because of the ongoing deterioration of the assets, by the time purchase was completed, the annual SAIDI impact would be expected to be much higher than three minutes. This creates an obvious disincentive to purchase assets that might otherwise be economically attractive.

98. Powerco recommends that, rather than simply apply a SAIDI adjustment based on historical performance, an option the Commission could consider is to make a SAIDI limit adjustment based on an independent assessment of the asset's condition at time of purchase.

9.2 Impact of asset transfers on operating and capital expenditure requirements – incentive on timing of asset purchases

99. The Commission suggests that the current regulatory framework incentivises distributors to purchase assets in years one, four and five, and particularly year four.

100. In principle, Powerco agrees that the regulatory framework should make EDBs indifferent to the year in the regulatory cycle in which assets are purchased from Transpower. In

practice, distributors purchase spur assets in accordance with their development plans and also at a time suitable to Transpower. Hence, they should not be penalised if the purchase occurs in year two or three of a regulatory period.

9.3 Other considerations

101. Powerco has four other concerns relating to the purchase of spur assets from Transpower:

- differences between a WACC return on the book value of assets purchased and the asset return rate used to determine the transmission charges avoided;
- assets which require significant investment during the first regulatory period;
- pre-approval of the avoided transmission charges to be included in recoverable costs; and
- possible changes to the transmission pricing methodology (TPM).

102. Under the DPP and applicable input methodologies, transmission charges avoided by the purchase of assets from Transpower may be included as a recoverable cost for five years. The charge that may be included is the amount payable in accordance with the TPM or a charge payable by an EDB to Transpower in respect of a new investment contract.[2]

9.3.1 Differences between a WACC return on the book value of assets purchased and the asset return rate used to determine the transmission charges avoided

103. The assets purchased will generally be connection assets. However, for “legacy” connection assets, that are charged for in accordance with the TPM, the asset return rate used to set the connection charges may be above or below a WACC return on the book value of the assets, depending on their age. This can disincentivise the purchase of newer connection assets, even if this would be in the best interest of end customers, if the asset-related element of the transmission charges avoided is significantly lower than a WACC return on the book value of those assets. We recommend that the Commission investigate this issue.

9.3.2 Assets which require significant investment during the first regulatory period

104. Some assets that Transpower is seeking to divest itself of, and which would benefit end consumers if they were divested, may require significant investment during the first regulatory period. If the transmission charges avoided are not sufficient to fund this additional investment, transactions which may be in the national interest may not proceed. We recommend that the Commission investigate this issue.

9.3.3 Pre-approval of the avoided transmission charges to be included in recoverable costs

105. The recoverable costs (i.e. the avoided transmission charges) are included in the relevant EDB’s pricing, but subject to the Commission’s approval after the pricing year has been completed. This creates a risk for the EDB, however small, that the Commission may not approve the recovery. To remove this risk, we suggest that the Commission amend the input methodologies to provide that it approve these costs prior to their being included in pricing. Another option would be for the Commission to provide a template that, if completed correctly, would ensure acceptance of these costs when the DPP is submitted after the pricing period.

[2] Electricity Distribution Services Input Methodologies Determination 2012 clause 3.1.3 (b).

9.3.4 Possible changes to the transmission pricing methodology (TPM)

106. Another concern relates to possible future amendments to the TPM. The current incentive to purchase Transpower assets relies on the calculation of avoided transmission charges in accordance with the TPM. As the Commission is aware, the Electricity Authority is currently consulting on fundamental changes to the TPM which were initially proposed in 2012. This review creates a risk for EDBs that are considering purchasing Transpower assets. It may be possible to "grandfather" the existing TPM for the purpose of calculating avoided transmission charges, but this would involve substantial administrative costs. We invite the Commission to consider possible alternative solutions to the disincentive created by the current TPM review, given that the review may extend for a considerable period of time.

10. Transition from CPP back to DPP (for Orion)

10.1 Price path

107. The Commission has indicated that it considers that the interpretation of section 53X(2) of the Commerce Act that is most consistent with the intended operation of the default/ customised price-quality framework is that the starting prices that apply when Orion transitions back to the DPP should be the prices that applied in the last year of the CPP. In our view, this is a pragmatic and sensible approach.

108. If, however, the Commission were to adopt the alternative interpretation that different starting prices should apply to Orion for the last year of the DPP at the expiry of the CPP, the Commission should explicitly state whether or not the assumptions it will use (e.g. WACC, CPI, population growth) will be updated with the latest available information, or it will use the same assumptions that were originally used to rest the DPP reset for other EDBs. For reasons of equity and certainty we believe that, in these circumstances, the inputs used to determine the final year prices for the transitioning EDB should be the same as those used to determine the DPP for all other EDBs that are subject to it.

10.2 Quality path

109. The Commission's view is that, at the expiry of Orion's CPP, the quality standard for the remainder of the next regulatory period should reflect the standard in place under the CPP, i.e. it should remain a pass/fail standard based on the average duration and frequency of interruptions. This view seems a pragmatic approach given that there would be a fairly short time period between coming off the CPP and moving to a new revenue-linked quality path at the commencement of the next DPP RCP.

10.3 Use of wash-up quantities to demonstrate DPP compliance

110. As part of the DPP reset, we would like to bring a technical DPP compliance issue to the Commission's attention. Currently, Powerco uses volumes to demonstrate DPP compliance that are drawn from the latest available information. However, these volumes are subsequently revised by retailers (or "washed-up") up to 14 months after the initial billed month. For example, when we set our prices in January 2014 for the 2014/15 pricing year we used billing data for the months of April 2012 – March 2013, but the November 2012 – March 2013 billing data are subject to a final revision to take place during February 2014 – June 2014.

111. While the final revision is typically immaterial, it can create a risk of a technical breach if there are significant changes (which happen from time to time). It would be helpful if the Commission could consider this issue and clarify its preferred approach for the industry.

APPENDIX A
POWERCO'S RESPONSES TO THE COMMISSION'S QUESTIONS ON THE DEVELOPMENT OF AN AGE-BASED SURVIVOR MODEL TO ASSIST CAPEX FORECASTING

What issues are there likely to be with the asset age information provided under information disclosure regulation?

While information on different types of asset is provided under Schedule 9b of the information disclosure requirements, the breakdown of the asset types that are actually driving the majority of the increases in near term renewal expenditure increases (specifically overhead line assets) is not granular enough to provide the accuracy needed for accurate modelling.

For example, cross arms are a materially significant component of Powerco's renewal expenditure, but cross arms are not included as an asset category (possibly because some lines companies do not regard them as separate assets). Cross arms are included in the poles category, but there are often multiple cross arms on a pole and the expected lives of the cross arms are substantially shorter than the poles. In addition, cross arm condition is not included in Section 12a.

The line item of wood poles also includes several different wood pole types that have diverse and materially different ageing characteristics. For example, hard wood poles tend to degrade from the outside inwards, whereas treated soft wood pole types tend to degrade from the inside outwards if cracks are evident that let weather into the untreated centre. The Larch pole types have different ageing characteristics from hard wood and treated soft wood types. These different wood pole types have quite different survivor curves.

Concrete poles include naturally reinforced and pre-stressed poles. These exhibit different ageing characteristics. However, the variations between types are probably not as materially significant as the errors associated with the survivor curves.

The asset age tranches in the information disclosed are probably too large to provide the degree of detail needed to accurately forecast the rate and timing of renewal expenditures. Much of the overhead network length was installed during the 1950s to the early 1980s. Following this time, a reduction in construction activity occurred, but we are now once again seeing a rise in construction levels. The exact rate at which the rise in renewal activity needs to occur is currently not very clear. Section 9b provides information on assets in ten year age tranches. Five or two year age tranches would provide better information for modelling purposes.

All of the points above may be able to be able to be accommodated by using larger standard deviations (for normal distributions) or smaller shape factors (for Weibull distributions) but the result would be that the model would predict flatter overall renewal profiles and that the scale of renewal activity needs a step change upward.

What alternatives, if any, are there to using asset age as a proxy for asset condition for electricity distributors, given the data currently available?

At this time in the industry's maturity, asset age is probably the best asset condition proxy the industry can use to forecast future asset renewal requirements. The EEA is currently working on guidance material for asset health indicators, but even if this guidance material were complete, there would still be a time lag before the industry could start using these indicators.

Asset age can only be a rough proxy when used to forecast the need for renewal expenditures. One of the main criteria governing renewal of overhead line assets is strength versus the expected loading (serviceability criterion). With wooden poles, there is a clearer relationship with age, as the below ground wood deteriorates due to fungi and bacteria, although this assessment needs to be tempered by information on prevailing environmental conditions. With concrete poles, the relationship is less straightforward and the designed fitness for purpose of the pole is more important.

For some asset types, such as cable and switchgear, age is not particularly relevant as a driver for renewal, but there is no obvious alternative indicator that the Commerce Commission could easily apply simply in the timeframe it has available.

For Powerco's network, overhead lines renewal dominates the required renewal expenditures relative to other asset categories. Therefore, with respect to our network, the focus of renewal modelling should be overhead line assets. This may not be the case for some more heavily urbanised networks.

What issues are there likely to be if we use normal distribution curves around the expected life of a network asset when forecasting replacement volumes?

Weibull distribution functions would be more conventional for modelling asset behaviours as assets age. If a normal distribution were used, the model could over-estimate the scale of renewal at the beginning of an asset's life if the standard deviation were not small compared with the mean. Use of the disclosure information as an input would be at odds with the use of a small standard deviation for the reasons given above. (Conversely, use of small standard deviations would mean the model would conclude that the ramp up of required renewal activity would need to be faster, which would create practical problems with field delivery.)

Are you aware of alternative options other than using an inflation-adjusted optimised deprival value to derive unit cost data? For example, unit cost data from overseas or other industry sources might be appropriate.

We are not familiar with overseas asset renewal cost data. However, a quick review of asset renewal unit costs across the industry could be done, especially for overhead line assets. For instance, Powerco has studied major work activities for some time and we know that typical rates for cross arm replacement are around $700, rates for pole replacement are around $4500, rates for re-conductoring are around $50,000 per kilometre, etc.

What risks do you see with using inflation-adjusted unit costs from the optimised deprival value handbook, and how could these risks be mitigated, for example, in the application of the model?

Use of unit costs from the optimised deprival value handbook, even if adjusted for inflation, would tend to under-estimate the actual costs associated with asset renewal activity. The ODV handbook replacement costs are based on the assumption that an efficient new entrant will operate in a competitive environment that existing routes or sites will be available, that particular project conditions and significant scale of construction will apply and a greater weight will be placed on actual project costs. We provide the following comments on these points:

- Efficient new entrant operating in a competitive environment

  We have no problem with assuming a competitive environment, but an efficient new entrant implies new build with none of the complications associated with dismantling the asset being replaced, providing shut down arrangements and customer notifications, job planning and delays due to shutdown windows and overall SAIDI management.

- Existing routes or sites

  In practice, significant expenditure on landowner negotiation is needed even if we have existing rights to the asset being replaced. Landowners usually apply restrictions on when and how the land can be accessed, which can add to costs. Territorial local authorities and the New Zealand Transport Agency can apply restrictions to how corridors can be accessed, which can add to costs.

- Particular project conditions and project scale.

  These assumptions are probably not generally applicable.

- Greater weight placed on project costs.

  This is reasonable for the purposes of asset renewal forecasting.

Between 2007 and 2012, Powerco's Asset Management Plans included multipliers to be applied to ODV unit rates. Using multipliers for assets other than overhead lines is probably satisfactory. However, for overhead line assets, using the multipliers would produce a distorted view of the way renewal work actually happens. To illustrate, there are typically four types of overhead line renewal job activity, but only one of these activities is represented by an ODV replacement cost, viz.:

- replacement of cross arms – not included in ODV replacement costs;
- replacement of conductors – not included in ODV replacement costs but potentially could be inferred;
- replacement of poles (usually with new cross arms at the same time) – may be inferred from ODV replacement costs;
- complete line rebuild – aligned with ODV replacement costs, but would need adjustment to accommodate the bullet points above.

Could this type of age-based survivor model be usefully applied if suitable unit cost data were not available, for example, by comparing the average age of each distributor's network against capital expenditure forecasts as a cross-checking exercise?

In principle, age based survivor modelling could still be useful even if unit cost data were not available, because the conclusions in terms of quantities could be used to indicate the size of the "wall of wire" problem, which could then be used to at least inform capex forecasts. However, such exercises could be difficult and possibly problematic in practice, because the use of average ages would obscure the skews in the asset age profiles.

Whether it would be appropriate to investigate the use of age-based survivor modelling for the total electricity distribution industry.

This concept may be worth pursuing for some assets and we note that the EEA is currently undertaking work to develop industry-wide guidance on asset health indicators. However, there may be some problems associated with different asset life experiences across the industry and the gathering of appropriate data to illuminate end of life symptoms.

Age based survivor modelling (actuarial model approaches) should be appropriate to overhead line assets and some other asset categories where there are large populations of assets, but may not be appropriate for some other asset types and work types. For some asset classes, the benefits of applying this sort of approach may not justify the costs. In addition, some asset types, such as underground cables, have end of life characteristics that are not well correlated with age.

Whether there is any other way that this type of modelling could be used at a high level to help inform our expenditure forecasts.

Even if there are doubts about the asset renewal unit costs to use, simply determining the approximate volumes to be replaced would be a useful piece of work because it would demonstrate whether and by how much the amounts of renewal activity need to increase, i.e. how steep the impending "wall of wire" is.