Submission on

Default price-quality paths for electricity distributors from 1 April 2015

and

Low cost forecasting approaches for default price-quality paths

15 August 2014

Table of Contents

1. Introduction

1. This is Powerco Limited's (Powerco) submission to the Commerce Commission's (Commission) on the following consultation papers:

    1. Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015
    2. Low Cost Forecasting Approaches for Default Price-Quality Paths.

2. We will comment on 2015-2020 DPP incentive schemes and compliance requirements on the 29th August.

3. This submission has been prepared in parallel with the Electricity Networks Association (ENA). We generally agree with the ENA submission apart from our preference for the use of 2014 as the base year for the opex forecast, rather than an average of 2013 and 2014. We also expand on options for refining the Commission's approach to forecasting capex and make Powerco-specific observations in relation to revenue forecasting and asset disposals that may not fully align with the ENA submission.

4. In Chapter 10, we set out a number of computational issues that should be corrected.

2. Summary of Powerco's views

5. The following table summarises Powerco's views on the Commission's proposals and provides recommendations for consideration. The items are listed in order of significance and materiality.

Capex Forecasting Approach	Powerco view	Recommendation
The Commission has proposed that capex forecasts be derived based on EDB forecasts. These will be subject to caps which limit the extent to which capex can increase relative to average historical capex. Network and non-network capex are to be forecast separately with different caps applied to each.	At a conceptual level we agree with the application of performance-informed caps on EBD capex forecasts. However, as implemented, the network capex forecasting approach leads to undesirable, presumably unintended, consequences for EDBs with increasing network investment requirements. The success of performance-informed caps is reliant on the mechanism allowing an appropriate level of investment. The Commission's proposal is currently flawed when applied across all EDBs due to the size of applicable caps and the historical average to which the caps are applied. The current mechanism may limit EDBs ability to make prudent investments.	Powerco recognises that the need to constrain the complexity of a low-cost forecasting approach. However, it believes that the capping approach should be supplemented by a rule that ensures EDBs forecast capex (particularly at the start of the period) doesn't fall below the FY14 actual level of expenditure. Such a 'floor' approach would mitigate potential unreasonable consequences (below) caused by the simplicity of the proposed mechanism. As stands the Commission's approach can constrain capex below current expenditure in the initial years of an RCP, which would effectively require an EDB to: – Significantly amend its planned work and approved projects, – Release service provider resource, and – Operate inefficiently due to reduced scale and fixed resource (e.g. design staff). In scenarios where the Commission is concerned about the impact of the floor on total capex, it could be re-profiled during the RCP to ensure an NPV neutral outcome. Potential mechanism aside, Powerco also recommends that EDBs be allowed smooth their capex allowances to reflect their particular circumstances (whilst ensuring NPV neutrality

		of the total expenditure during the RCP).
Disposals	**Powerco view**	**Recommendation**
The Commission has forecast losses on disposals by applying an industry-wide percentage of losses on disposals against the calculated disposals amount and included this in Other Regulatory Income allowance.	Applying an industry-wide percentage (88%) of gains/(losses) on disposals adjustment is less effective than a company-specific ratio which would provide improved accuracy of forecasting.	Replace the industry ratio with one based on disposals actually recorded by the company in the last one or two years. This approach would still satisfy the Commission's low cost forecasting criterion, but would achieve greater accuracy.
Opex Forecasting Approach	**Powerco view**	**Recommendation**
The Commission has based its opex forecasts on FY13 values.	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. The Commission indicates that an atypical year should not be used as the base year. For Powerco, 2014 was close to being a normal year, while 2013 an atypical year due to unusually benign weather in Powerco's network regions. A significant proportion of the year-to year change in opex is due to storm-related expenditure.	Using FY14 figures as the base over FY13 is a logical amendment as it would recognise; - the significant proportion of opex is weather-related and FY13 was an unusually mild year; - that FY14 is the most recent year and consequently reflects Powerco's most recent cost structures, including any efficiencies; - the opex IRIS as proposed assumes a FY14 base going forward and it would be appropriate to align the base years.
Revenue Forecasting	**Powerco view**	**Recommendation**
The Commission has modelled residential electricity use based on population forecasts from Statistics New Zealand and the Commission's own assumption of a 0% change in electricity consumption per user.	Powerco generally supports using population and GDP growth to forecast volume growth. However, recent improvements in energy efficiency have led to divergence between these drivers and consumption. Average residential consumption across our networks has declined by 0.9% per annum (2010-2014). We expect these trends to continue in RCP2, making the	We support the ENA proposal to project real revenue growth by using actual historical trends for each EDB, or to assume reducing energy consumption per residential household of between 1.1% and 1.5% per annum.

	assumption of 0% growth inappropriate.	
Treatment of assets purchased from Transpower	**Powerco view**	**Recommendation**
Assets owned at 31 March 2014 included in the RAB. Assets forecast to be purchased in a future regulatory period are not recognised in the reset. An adjustment to the quality targets is proposed for purchases transacted during the regulatory period based on historical reliability information received from Transpower	Powerco welcomes clarification on how assets purchased from Transpower will be treated in RCP2, we particularly support the inclusion of a quality path adjustment mechanism. We support the pre-approval of the recovery of ACOT as it removes an element of uncertainty that currently exists. However, Powerco is concerned the proposed approach may be difficult to apply in practice.	Powerco will provide a detailed response on the treatment of assets purchased from Transpower in the Input Methodology drafting consultation.
Energy efficiency and demand-side management incentives	**Powerco view**	**Recommendation**
Introduction of a mechanism that compensates distributors for revenue forgone and neutralise the incentive to commission assets based on expected asset life.	Powerco supports the Commission's proposals as they are consistent with the recommendations made by the ENA working group paper. However while the framework being developed will help accommodate energy efficiency and demand-side management initiatives, it will not provide material levels of incentive.	We recommend that that the Commission amend the proposal to enable it to consider tariff-based energy efficiency proposals on a case by case basis.

6. The following table summarises Powerco's additional views on the Commission's proposals.

Productivity-based rate of change	Powerco view	Recommendation
The Commission's current approach to estimating opex partial productivity in the electricity distribution sector requires reconsideration.	Further clarification is required to support the reason for not considering Economic Insight's empirical analysis..	We recommend that the Commission provide robust justification for why the EI and PEG analysis should be discounted. In the absence of any such evidence a negative productivity estimate should be adopted.
Treatment of catastrophic risk	**Powerco view**	**Recommendation**
Introduction of a provision that allows a DPP to be reconsidered following a catastrophic event.	We agree with the ENA that, in certain circumstances, both the price path and the quality standards should be able to be reconsidered. We also support the proposal to include a recoverable cost term to compensate for financial losses between the time the price path is reset after a reopener and the catastrophic event itself. We reiterate that the use of a percentile estimate of the weighted average cost of capital (WACC) above the midpoint does not compensate EDBs for bearing catastrophic risk as the methodology used to determine the final regulatory WACC value explicitly excludes any consideration of asymmetric risk, which includes catastrophic risk.	The price path reset should compensate suppliers for demand risk incurred prior to the reset and other additional net costs incurred prior to and after the price reset as a consequence of the catastrophic event.
Treatment of pass-through and recoverable costs	**Powerco view**	**Recommendation**
Currently while the principle is that distributors should be able to fully recover pass through costs and recoverable costs,	It is not always possible for distributors to recover costs in full under the current mechanism and this leaves EDBs exposed to financial risks outside their control.	The Commission is proposing a modified version of Vector's proposal, i.e. revenue control for transmission charges and an "ascertainable costs" approach for other pass-through and recoverable costs. Powerco generally supports the proposal

this is not always the case.	Powerco agrees with the ENA that it is important that EDBs be able to recover pass-through and recoverable costs in full as quickly as possible without, in effect, incurring a perpetual recovery deficit. Achieving this may require costs incurred in one RCP to be recovered in the following RCP.	and will comment in more detail in its submission on the Compliance paper.
Customer service lines	**Powerco view**	**Recommendation**
Currently the Commission has not provided any guidance or provisions to address public safety issues associated with customer service lines.	This is an important public safety issue. Customer service lines are continuing to fall into disrepair because customers are unaware that they are responsible for maintaining them. While not responsible in most cases, EDBs are in a position to offer services to address the issue but the regulatory framework does not provide a mechanism to recover the associated costs.	The ENA has provided recommendations and supporting information to the Commission. We support the ENA work and encourage the Commission to proceed with its recommendations, including the creation of a recoverable cost category for costs related to customer service lines and including a provision for pre-approval of cost recovery.
Forecasting uncertainty	**Powerco view**	**Recommendation**
No additional allowance to reduce the probability or an EDB making a customised price-quality path proposal.	We agree with the ENA's analysis which shows that most EDBs have not achieved target return rates in the first two of the three years of RCP1 due to forecasting uncertainty.	The Commission should review RCP1 forecasting performance and consider these results before finalising its forecasting methods.

3. Capital Expenditure Forecasts

7. The Commission has proposed that capital expenditure (capex) forecasts be derived based on EDB forecasts. These forecasts will be subject to caps in order to limit the extent to which they can increase relative to average historical capex.

8. The Commission's decision is to forecast network and non-network capex separately with different caps applied to each.

9. At a conceptual level we are comfortable with the proposal and note that it is consistent with our suggested approach[1]. However, we note that in our previous submission we proposed a maximum cap of 150% and do not believe that a 120% cap provides sufficient flexibility. We believe it is a pragmatic solution that can be used while more accurate approaches (e.g., renewal modelling) are developed.

10. We are also comfortable with the proposed approach to non-network capex.

11. However, as implemented the forecasting approach for network capex leads to a number of undesirable, presumably unintended, consequences for EDBs with increasing network investment requirements. Powerco recommends that further consideration is given to the reference period used to determine the cap and how the application of the cap impacts on EDBs allowed expenditure; particularly in the early part of the RCP (a sense check mechanism is required).

12. Powerco also considers that the Commission should allow some flexibility for an EDB to confirm to the Commission its preferred expenditure profile during the RCP2 based on the Commission's final forecast (ensuring NPV neutrality over the period). We expand on these comments below.

3.1. Historical spend used to establish the allowance

13. The applicability/relevance of the historical spend, used to determine the level of the cap of an EDBs forecasts, will vary based on a number of factors: the historical period used, the circumstances applying during that period (including regulatory rules), the timing gap before the forecasts apply and the trend of an EDBs expenditure, both since the start of the reference period and into the future.[2]

14. The Commission has used the average capex of the five year period 2009/10 to 2013/14 as the base for the forecast. There is little comment in the paper about the rationale for the time period chosen (length and timing). We note that the Commission's approach is similar to the averaging period used in the initial gas DPP, where there was also very little discussion about a suitable averaging period to use. We assume that in both instances the Commission's objective is to ensure that an EDB's forecast capital expenditure, allowed for as part of the DPP, is constrained to a modest (non-step change) level of growth over broadly current levels of expenditure.

15. We note that for opex, the Commission has sought to use the most recent 'typical' year as a base for the forecasts. The rationale is that it best reflects the latest circumstances of the EDB.

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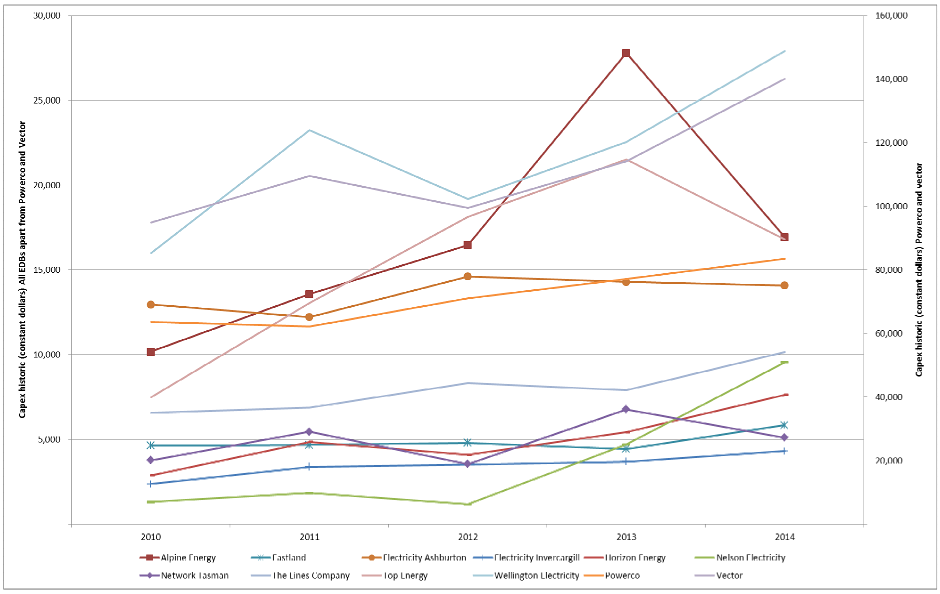
[1] As signalled in Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper, 30 April 2014, Section 3.3.5.

[2] These are not significant issues for non-network capex forecasts due to the use of alternative caps and its inherent variability.

16. We consider that a similar approach should apply to the capex methodology and that the historical reference period should be based on more recent, representative actual expenditures. It is clear that most EDBs have a consistent trend of flat or increasing capex (in constant terms) as shown by the graph below. Consistent with our published asset management plans Powerco's annual level of network capital expenditure (driven by asset renewal) has increased year on year since 2011.



17. The table below shows the percentage difference between 2010 capex and 2014 (forecast) capex (in constant dollar terms) across non-exempt EDBs. There are only two EDBs whose 2010 capex is less than 2014, and for 11 EDBs, the capex increase has been above 30%. The average increase between 2010 and 2014 is 84% (Otagonet removed).

EDB	% change 2010 to 2014
Alpine Energy	66%
Aurora Energy	-33%
Centralines	-59%
Eastland	26%
Electricity Ashburton	9%
Electricity Invercargill	82%
Horizon Energy	165%
Nelson Electricity	630%
Network Tasman	35%
Powerco	31%
The Lines Company	55%
Top Energy	124%
Unison	1%
Vector	48%
Wellington Electricity	74%

18. Clearly, basing the cap on an average of a historical time period going back to 2010 when expenditure was considerably less than current levels (in constant dollar terms) will not reflect the latest investment needs of EDBs.

19. Asset management approaches used by EDBs are maturing in part instigated (or at least accelerated) by the introduction of the Part 4 framework with its emphasis on, long term, "whole of life" asset management. It can therefore be expected that more recent expenditure levels will be better informed. Recent initiatives amongst EDBs have contributed to this trend including:

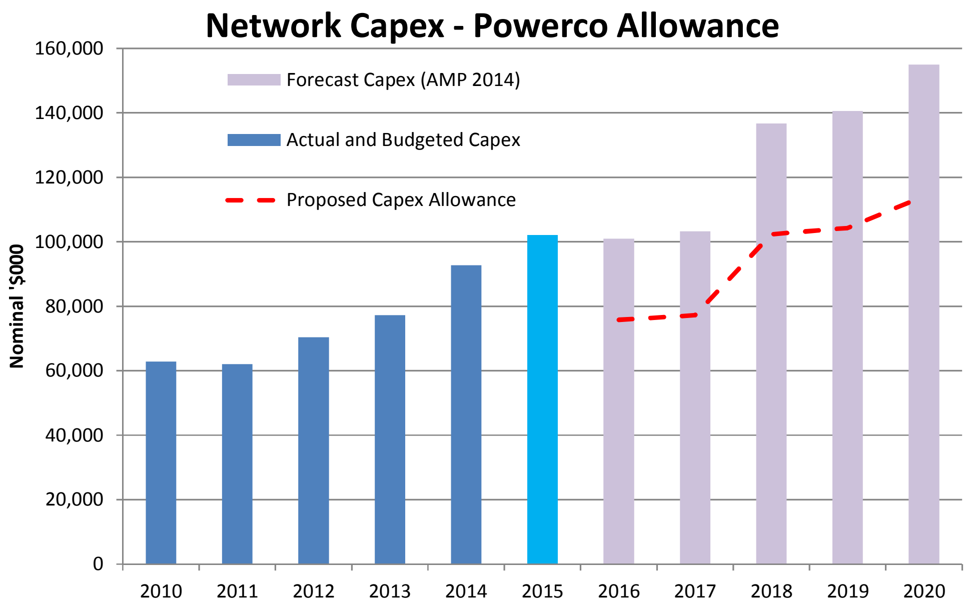
- The Commission's facilitation of improved asset management through the use of AMMAT disclosures; and
- The introduction of improved forecasting techniques amongst EBDs (e.g. asset health and survivor curves).

20. The historical period used to set the cap is weighted towards the beginning of RCP1 and includes expenditure prior to the introduction of the DPP mechanism and associated quality standards. In Powerco's case, expenditure during the period 2010 to 2014 is not representative of current or future investment requirements.

21. In our view, using a three year period (2012-2014) is more appropriate. A three year period should also be sufficiently long to mitigate large one-off ('lumpy') expenditures.

3.2. Network Capex – Impact on Powerco

22. The following chart depicts the impact of the Commission's current proposal on our planned expenditure during RCP2.



23. The Commission's modelled allowance provides $474m of capex over RCP2. Despite the application of the 120% cap , this proposed allowance represents:[3]

- A $163m shortfall against our planned investments for the period; and
- An allowance that is **26% below** FY15 budget.

[3] Figures are nominal and reflect the capex forecasts included in our 2014 AMP update.

24. As we have indicated in our recent Asset Management Plans, indications are that underlying reliability performance at specific locations across our network is being affected negatively by a combination of deteriorating condition, increasing age, and asset type-related issues. At current levels of expenditure, our asset stock is progressively maturing (ageing). This is particularly the case for overhead network assets. Parts of our network are becoming more vulnerable to severe weather and exceptional storm events. This is on one of the main reasons why Powerco has targeted increased investment in the area of network asset renewal during the last three years of the current RCP. Even at current levels of expenditure we are able to manage SAIDI and SAIFI, but we are unable to build operational margins to provide a buffer against severe weather events.

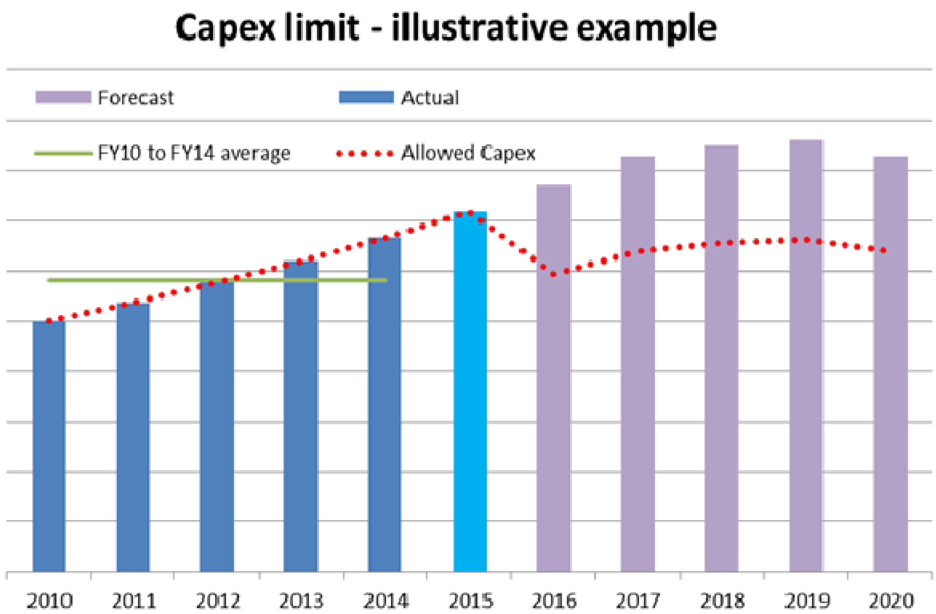
25. Our on-going analysis indicates a need to continue lifting both growth and renewal capex in targeted areas across our networks in order to begin to reverse the above trends. To ensure we can meet our asset management objectives in the short term (under the DPP) we need to be able to maintain our current level of expenditure.

26. As a prudent asset manager our aim is to minimise the cost-of-ownership of our assets in the medium to long-term. As signalled in our AMP, our reliability performance and increasing condition-related faults indicate the need for additional renewal capex to maintain safety and service quality. In the face of these capex constraints we may be limited to choosing less optimal solutions (e.g., increased conducting jointing to defer replacement).

27. Our objective is to meet the needs of our stakeholders by managing our network on a commercial and sustainable basis over the long-term. The significant capex constraints proposed under the draft DPP will undermine our ability to achieve this.

3.3. Network Capex – Forecasting Approach

28. We agree with the application of performance-informed caps on EBDs AMP forecasts. However, as depicted below, the proposed approach can have undesirable, presumably unintended, consequences for an EDB with increasing investment requirements.



29. While this is a stylised example, it demonstrates what we believe is a significant flaw in the proposed forecasting methodology. By constraining capex below current budgeted levels (FY15 above) in the initial years of an RCP it would effectively require an EDB to:

- Significantly amend its planned work and approved projects,
- Release service provider resource, and
- Operate inefficiently due to reduced scale and fixed resource (e.g. design staff).

30. The degree to which the proposed mechanism will support an appropriate level of investment will depend on a number of factors. Of these, the most relevant are the size of applicable caps and the historical average to which the caps are applied.[4]

3.4. Capping Mechanism

31. The Commission has chosen two caps (110% and 120%). The proposed cap for Powerco is 120%, reflecting the relative accuracy of the company's expenditure forecasts during RCP1 (as measured by actual spend against budget). The Commission argues that this provides sufficient scope to accommodate trends of increasing capex for most EDBs. As depicted above this would not be the case for an EDB with progressively increasing investments across RCP1 and RCP2.

32. The proposed caps have been used to constrain the capex of 10 EDBs. Acknowledging the need to reduce complexity in a low-cost forecasting approach, we believe that the two caps should be supplemented with a rule that includes a 'floor' to ensure that, at a minimum, current expenditure levels can be maintained.

33. The proposed floor would limit any annual downward adjustment to ensure that the allowance doesn't fall below the FY14 actual level of expenditure.

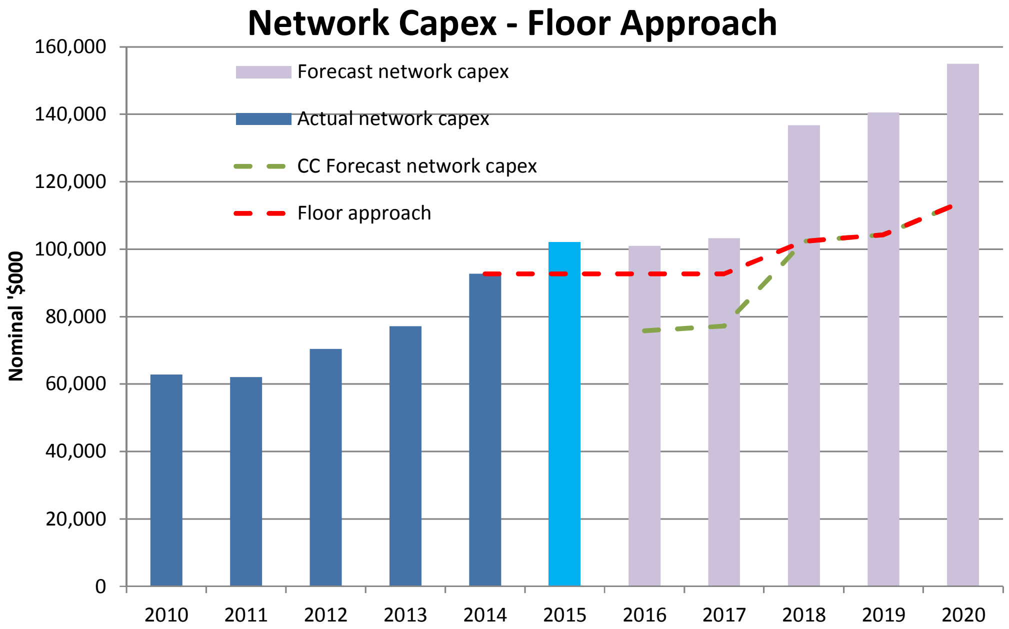
34. As it stands the Commission's approach, which constrains capex below current budget (FY15 in the above chart), would effectively require an EDB to:

- Significantly amend its planned work and approved projects;
- Release service provider resource; and
- Operate inefficiently due to reduced scale and fixed resource (e.g. design staff).

35. If the Commission is concerned about the impact of the floor on an EDBs total RCP capex allowance then its expenditure could be re-profiled to ensure an NPV neutral outcome.

36. We illustrate the impact of this mechanism on our forecasts below.

[4] Other factors include use of a capex incentive mechanism.



37. As we have illustrated, there are plausible circumstances where the simplicity of the proposed mechanism can have unreasonable consequences for EDBs. Use of a floor would help mitigate these and ensure EDBs can:

– Retain the majority of planned work and approved projects;

– Maintain availability of service providers; and

– Maintain momentum within current investment plans.

3.5. capex Recommendation

38. For the purposes of forecasting capex during RCP2, Powerco :

– Supports the application of a cap on forecast expenditure increases relative to current levels of expenditure but recommend that the Commission reconsiders the historical reference period used to establish the cap. In this regard the reference period should reflect more recent / current levels of actual EDB expenditure and the cap should limit future increases relative to this benchmark.

– Notes the perverse (and presumably) unintended outcomes which result from the Commission's current approach which, in the case of Powerco, imply that current levels of capital expenditure should be reduced by approximately 25% in the first year of the DPP. Powerco recommends that the Commission introduces a sense check as part of its forecasting approach and we have proposed a possible mechanism for consideration, based on the application of an "adjustment floor".

– Recommends that the Commission considers allowing EDBs to elect to smooth their DPP capex allowances to reflect their particular circumstances - whilst ensuring NPV neutrality of the total expenditure during the RCP.

39. Powerco will be responding to Commission proposals to introduce a capex incentive mechanism as part of its submission on the 29 August 2014. However, we concur with the ENA initial position in this area but note the obvious interdependence between the robustness of the Commission's expenditure forecasts and the effectiveness of any incentives that are applied to those forecasts.

4. Operating expenditure forecasts

40. This section discusses the Commission's proposed approach for forecasting opex allowances during RCP2. The methodology uses a number of drivers to project forward an initial opex amount (base year).

41. The ENA submission raises a number of issues with the methodology. We support the basis for these views. Below we set out additional views on the suitability of the approach when applied to Powerco's expenditure and particular circumstances.

4.1. Base Year

42. The Commission has based its opex forecasts on FY13 values. It states that it has used 2013 because:

- data for 2014 has not yet been disclosed; and
- distributor estimates of expenditure in 2014 suggest the year was atypical.[5]

43. In our view, the lack of disclosed 2014 opex data is not a valid reason as it will be disclosed by the end of August, and will then be available for inclusion in the model.

44. In our view the methodology should use the most recent available annual outturn figures. In the absence of one-off large expenditures this opex level will best reflect current and future cost structures. We also agree with the Commission's view that using: "the most recently available year prior to the reset would help ensure efficiency gains achieved prior to the start of the regulatory period are passed on to consumers."

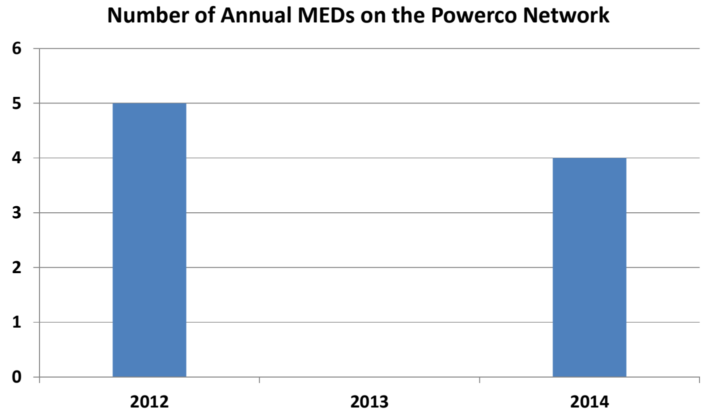
4.2. 2013 was not a typical year for Powerco

45. For Powerco it can be demonstrated, from an operational perspective, that 2013 was not a typical year, while 2014 was closer to being 'normal'. A significant proportion of our network opex is driven by the need to respond to weather events. In terms of extreme weather 2013 was an unusually benign year reducing this expenditure below 'typical' levels. Basing future expenditure on 2013 effectively 'locks in' this lower level of network opex, potentially constraining our ability to respond to future extreme weather efficiently.

46. The chart below shows the number of SAIDI major event days or MEDs[6] experienced across Powerco's networks over the past three years. In 2013 there were no MEDs on the Powerco network due to relatively benign weather. In 2014 there were four MEDs and in 2012 there were five, the latter being more typical numbers.

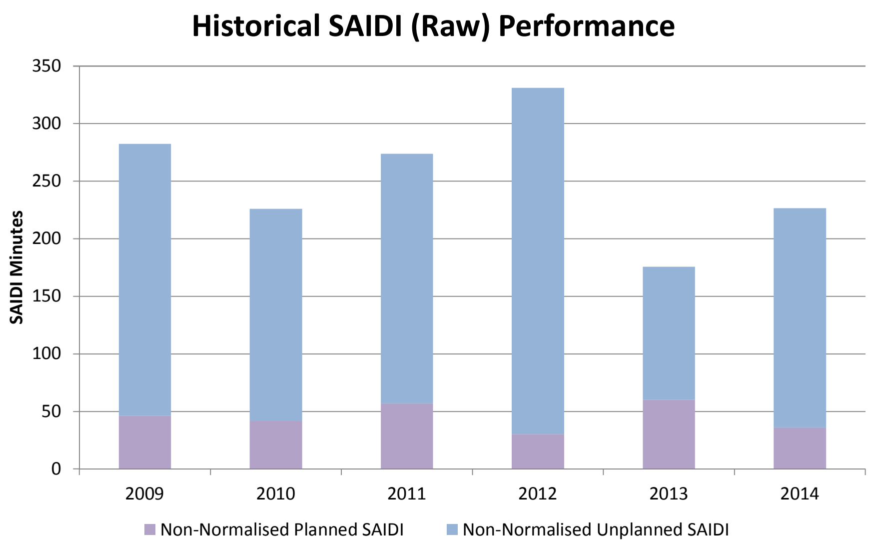
5 *Low Cost Forecasting Approaches for Default Price-Quality Paths*, Commerce Commission, 4 July 2014, (LCFA Paper) para. 3.8, p.11.

6 Days on which SAIDI exceeded the "boundary" value and is consequently "normalised



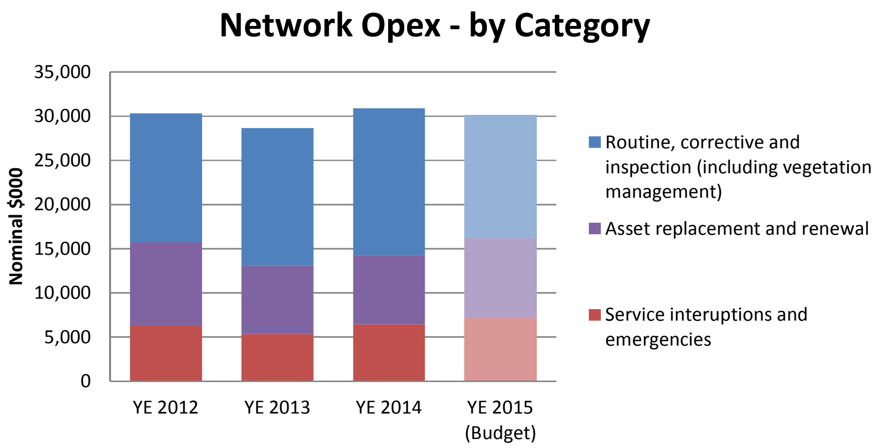
47. Network opex is directly influenced by the level of required work following faults and outages. Similarly the number of storm-related outages will influence our annual SAIDI performance (an EDBs vulnerability to exogenous factors such as storms and how this fits with the regulatory framework is an issue which we will be responding to in our submission on 29 August).

48. The following chart shows Powerco's SAIDI performance for 2010 to 2014. The purple section shows planned SAIDI.[7] The blue section reflects the impact on the network of weather events. It is clear from the chart that 2013 was an abnormally low SAIDI year and this flowed through to a reduced level of reactive maintenance (opex).

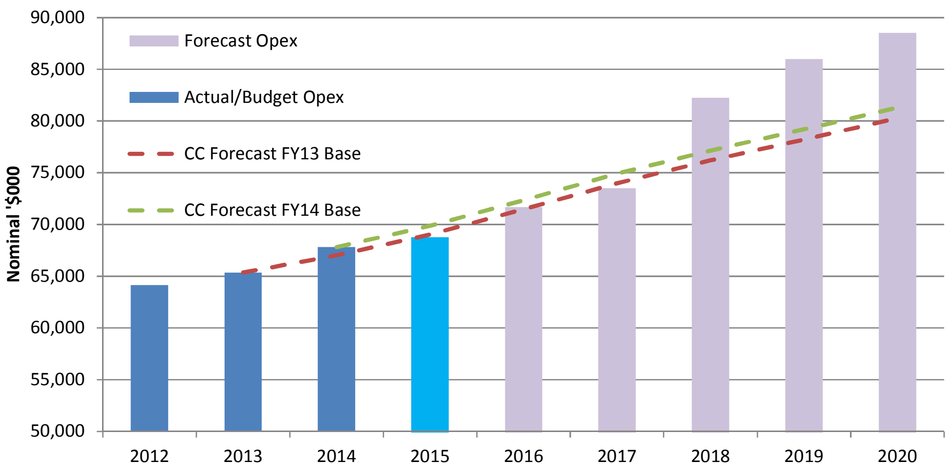


49. The lower level of network opex during 2013 was driven by reductions in weather related reactive maintenance particularly to service interruptions and emergencies work.

7 More planned work was able to be undertaken in 2013 because of the unusually long periods of settled weather in that year.



50. As depicted below the use of a 2014 base year would not result in a significant shift from our current forecast.



4.3. Additional Costs

51. As the Commission proposes to apply the same base year approach to non-exempt EDBs it is important that all relevant (and comparable) expenses are captured in the base year. For example, the risks associated with a catastrophic event could either be mitigated through self-insurance (with premiums included in base opex) or, as in Powerco's case via maintaining increased debt facility headroom (with costs flowing into interest expense and therefore not captured in the opex base). Other EDBs will no doubt have other examples and whist we appreciate the difficulty of providing for bespoke arrangements, under the low cost forecasting approach, we recommend that a mechanism is introduced to allow EDBs to submit such costs for consideration by the Commission.

4.4. Network Scale Effects

52. The Commission has used two variables to reflect opex changes due to network scale effects, these are changes in network length, and changes in the number of connections (ICP).

53. We note that the Commission will receive updated ICP growth and network length data via EDB information disclosures in late August and that these may impact opex forecasts.

4.5. Partial Productivity

54. This is discussed in Chapter 5.

4.6. Escalators

55. The ENA Working Group considered in detail how the accuracy of the opex and capex escalators could be improved. They recommended the Commission pursue industry and asset-specific indices, applying composite escalators and combining the forecasts of more than one forecaster to reduce the risk of forecasting error. We recognise the working group's recommendation is more complex than the current approach, and there is not time to implement at this reset. However, escalators have a material impact on expenditure allowances. There are clearly methods available to increase accuracy and these should be applied where possible.

56. At this reset we consider there is enough evidence to show a disparity in the Labour Cost Index between our sector and the overall economy. We recommend the Commission reflect this, as per the ENA submission.

4.7. Opex Recommendations

57. In summary, in Powerco's view it would be preferable to use FY14 figures as the base, because:

- a significant proportion of the our network opex is weather-related and FY13 was an unusually mild year;
- FY14 is the most recent year and consequently best reflects our current cost structures; and
- the opex IRIS as proposed assumes a FY14 base year and for consistency it is appropriate to align base years.

5. Productivity

58. The ENA commissioned an in-depth independent review of the Economic Insights (EI) report. This provides a range of detailed analysis that we do not repeat in this submission.

59. Our main concern is EI's and the Commission's lack of rationale for concluding that TFP and opex partial factor productivity will be flat going forward, stating that:

> "While five of the six TFP specifications we have examined have pointed to a negative TFP growth rate for the last decade, there is also some expectation from experts, including the AER and the Australian Energy Market Operator (AEMO 2013, p.ix), that positive electricity demand growth will resume, albeit at a reduced rate compared to the period before 2007."[8]

60. To assist our understanding we recommend that the Commission provide its reasoning why the EI and PEG analysis should be discounted. In the absence of any such evidence the "evidence supported" negative productivity estimate should be adopted.

61. In our experience, the conclusion (from the TFP analysis) that inputs are growing faster than our outputs is not unreasonable. A range of changes in our operating environment

[8] Denis Lawrence and John Kain, *Electricity Distribution Industry Productivity Analysis: 1996-2013*, Report prepared for the Commerce Commission, 24 June 2014 (EI Report), p. iv.

have imposed costs, such as tree management regulations, health and safety legislation as well as additional challenges of managing an ageing network. As already discussed in this submission, technological changes are reducing electricity use, but not delivering as many changes to how we operate the electricity network. This dis-joint is highly unlikely to change in the future.

6. Disposals

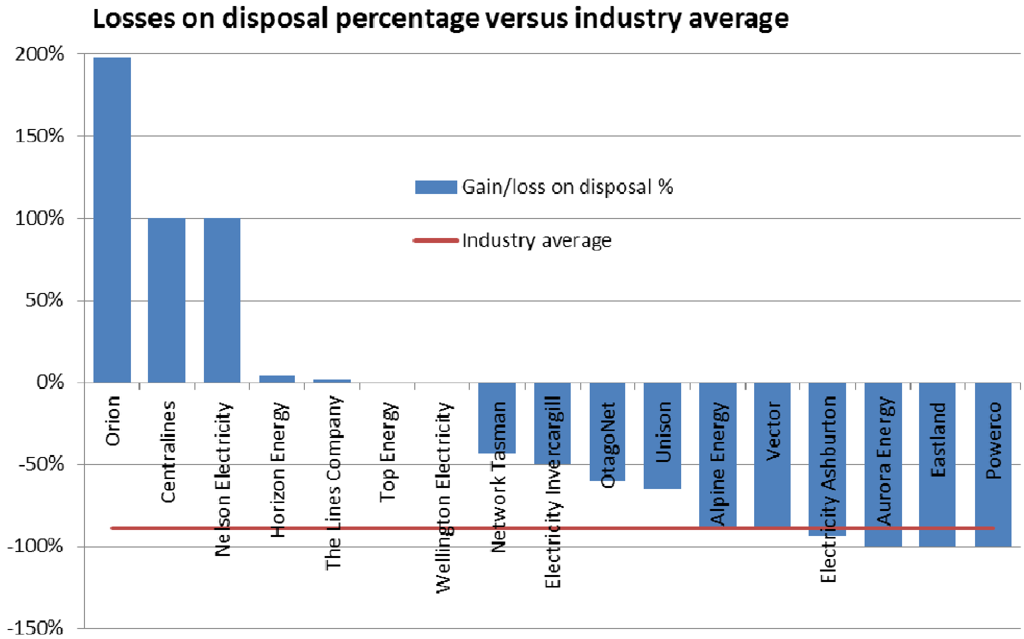
62. The Commission has forecast losses on disposal by taking an average of the last four years disposals for each EDB and has then applied an industry-wide percentage of loss on disposal against this average. The Commission has then included an allowance for losses on disposal as a negative amount within Other Regulatory Income. During RCP1 an allowance for losses on disposal was included within the operating expenditure allowance.

6.1. Comment

63. Powerco supports identifying losses on disposal as a separate forecast item and providing a specific allowance for this amount. An allowance for losses on disposals is required to ensure that EDBs can earn an appropriate return on their assets over their life.

64. We also support including it as a negative amount within Other Regulatory Income as it allows for a more easily understood opex allowance that will now be able to be reconciled to Information Disclosure operating expenditure.

65. However, Powerco believes that applying an industry-wide percentage of gains/losses on disposal is inappropriate due to the wide range of approaches taken by EDBs. The following graph[9] demonstrates this variance in outcomes.

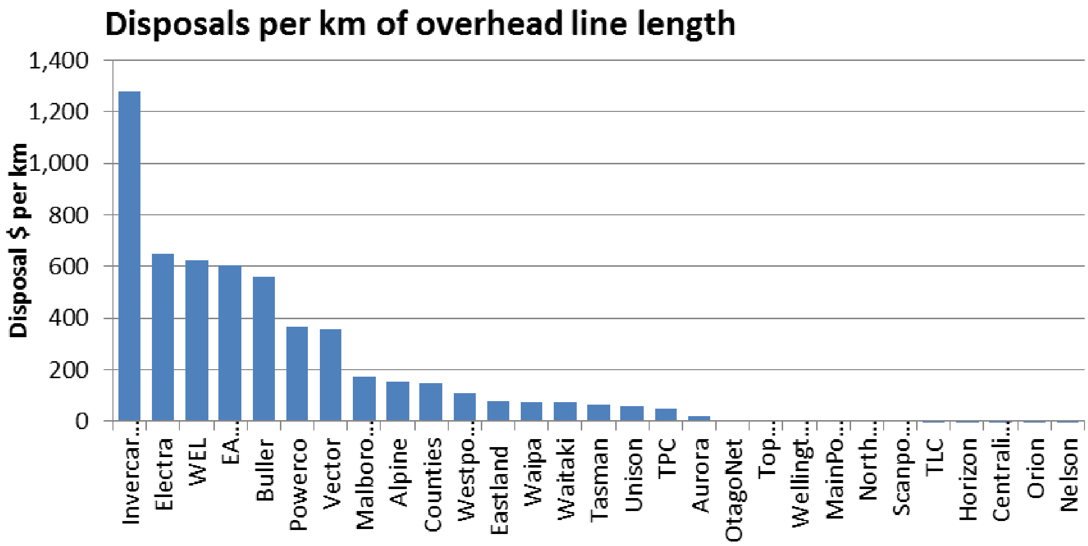


66. The above graph shows that some EDBs have recorded gains on disposal (with a nil value of disposed assets recorded in RAB) and other EDBs show losses on disposal

9 Commerce Commission - Model 20 Other regulated income and asset disposals draft EDB reset

with no proceeds received. The range of possible outcomes means that picking the average result and applying it to all EDBs equally is clearly inappropriate. Some EDBs that have previously made gains on disposals will now be assumed to make a loss, and some EDBs that have not received any proceeds from disposals will now be assumed to receive some.

67. We believe that the divergence in gain or losses on disposal within the industry is a result of different approaches being taken towards disposals. The graph below shows that while most companies did record some level of disposals in 2013 a large number did not.



68. Such industry divergence suggests that the use of an industry-wide value is inappropriate and should be replaced by a company-specific ratio. This ratio could be based on genuine disposals actually recorded by the company in last one or two years. This approach would still meet the Commission's low cost forecasting objective, but would achieve greater accuracy and not unfairly reward some EDBs and punish others.

7. Constant Price Revenue Growth Forecasts

69. Constant price revenue growth has been forecast by the Commission for each EDB using both regional and EDB specific data. For commercial and industrial consumers real revenue growth is forecast using regional forecasts of GDP.

70. The Commission has modelled residential electricity use based on population forecasts from Statistics New Zealand and its own assumption of a 0% change in electricity consumption per user.

7.1. General Comments

71. The Commission's rationale for its 0% growth assumption is:

> "Electricity price increases are starting to moderate, economic activity is picking up and electric cars are becoming viable. Taken together, our expectation is that electricity use per user is more likely to remain broadly constant." [10]

[10] LCFA Paper, para. 5.19

72. This is the same approach that was undertaken during the previous regulatory period. As pointed out by ENA, this approach has significantly over-estimated residential consumption over RCP1.

73. We note the EI paper on productivity analysis includes comments (on p.39) that the reduced growth rate in demand observed since 2007 "seems to be separate from the short term effects of the global financial crisis" and that "this change has also been observed in Australia, Canada and the US". The authors also note that "lower growth is likely to continue for some time.'[11]

74. We support the ENA proposal to project real revenue growth by using actual historical trends for each EDB, or to assume reducing energy consumption per residential household of between 1.1% and 1.5% per annum.

75. We agree with the Commission's modelling of growth in electricity consumption by commercial and industrial users, which is broadly consistent with our own internal modelling.

7.2. Energy consumption on the Powerco network

76. The table below summarises historical growth trends for energy consumption and ICP numbers on the Powerco network. Some key points to note are:

– the compound annual growth in total residential consumption across Powerco's networks has been -0.9% per annum over the 2010-2014 period;

– the compound annual growth in residential consumption per ICP has been -1.5% per annum over the 2010-2014 period; and

– growth in ICP numbers has continued, but the rate of decline in consumption per ICP has accelerated.

	Residential information					Growth	
	2010	2011	2012	2013	2014	2010-2014	2012-2014
MWH consumption	2,626,853	2,533,368	2,610,884	2,613,450	2,531,778	-0.9%	-1.5%
ICPs	315,984	317,593	319,296	320,527	322,899	0.5%	0.6%
MWH/ICP	8.3	8.0	8.2	8.2	7.8	-1.5%	-2.1%

77. Although, as the Commission notes, the rate of increase in electricity prices has recently moderated, this has not led to any reduction in the rate of decline in residential consumption per ICP. On the contrary, the rate of decline has accelerated. We believe that the consumption trend is mainly being driven by technological advances in appliance efficiency, climatic warming and growth in residential photovoltaic (PV) installations rather than changes in price. We discuss below why we believe these trends can be expected to continue in the 2015-2020 period. We also note that price changes may only have a positive effect on consumption if prices decline in real terms. Current price trends, while moderating, do not suggest a decline in real prices is likely.

78. Powerco believes that the decline in volumes seen over the past four years is due to a number of effects that are likely to continue during RCP2, namely:

– Improved home insulation and increasingly efficient space heating;

– Increasingly efficient appliances such as televisions, refrigeration, hot water cylinders and lighting and the proliferation of these more efficient appliances;

11 EI Report, p.39.

– Increasing penetration of solar photovoltaic (PV) generation;

– Increasing penetration of smart meters leading to greater consumer response; and

– Warmer temperatures.

79. Powerco agrees with the findings and analysis of the Sapere report "Trends in Residential Electricity Consumption, 5 August 2014". Below we provide supplementary information on electric vehicles and PV (particular to the Powerco network).

PV Penetration and Smart Meters

80. Currently embedded residential PV generation on Powerco's network is about 2,800kW representing approximately 700 installations. The trend of installation is shown below. The rate of installation growth is expected to continue growing with the number of installations expected to at least double by 2020.

Year	Number of Installations	Capacity (kW)
2008	11	19.9
2009	19	8.8
2010	17	44.2
2011	34	136.8
2012	120	503.5
2013	267	1,075.7
2014 (data incomplete)	251	928.3
Total	**719**	**2,767.1**

81. The penetration of smart meters is currently about 50% in Powerco's Western region and 30% in its Eastern region. These figures are expected to rise to about 70% and 60% respectively by 2017/18. The increased penetration of smart meters will increase our consumers ability to monitor their energy use and respond accordingly.

Electric Vehicles

82. The Commission states that "electric cars are becoming viable", which suggests it believes that the uptake of electric cars will reach a material level in the near future, impacting residential energy consumption in RCP2. We believe the available evidence contradicts that view.

83. Electric vehicle numbers are increasing in the United States and Europe, but sales there are encouraged by tax credits and other subsidies that do not exist in New Zealand. The number of electric vehicles registered in New Zealand in 2013 was 130 compared with 186,667 petrol vehicles and 54,884 diesel vehicles. Hence, although the number is slowly increasing, the proportion of new electric vehicle registrations is below 0.1%.

84. Current reductions in residential consumption equate to around 24 GWh per annum. As electric vehicles are estimated to use around 3,000 kWh per annum, it would take 8,000 additional electric vehicles per annum to fill this gap, equal to about 70% of the new vehicles registered annually in Powerco's network areas.

85. While sales of electric vehicles may well increase, it is inconceivable that the number sold would be sufficient to materially offset the current reductions in residential consumption that have been observed on Powerco's networks over the 2010-14 period.

8. Treatment of assets purchased from Transpower

86. Powerco welcomes clarification on how assets purchased from Transpower will be treated in RCP2. We particularly support the inclusion of a quality path adjustment mechanism that recognises the historical reliability of the purchased assets, as the current potential for there to be a negative effect on quality path compliance if the assets purchased have a poor quality performance history can discourage purchases that may be in the interests of consumers and the nation as a whole.

87. We encourage the Commission to consider a similar provision for assets purchased, or forecast to be purchased from Transpower in the current regulatory period. The quality service targets currently proposed do not recognise the historical reliability of these assets and therefore may create a false baseline for the second regulatory period.

88. We note that there remains an incentive to transact purchases in years 4 and 5 of the regulatory period. We encourage the Commission to consider options to reduce or eliminate this incentive as it has the potential to lead to efficient transactions being delayed.

89. We support the pre-approval of the recovery of ACOT as it removes an element of uncertainty that currently exists. However, Powerco is concerned the proposed approach may be difficult to apply in practice. We note that there will be a very short "window" during which the annual pre-approval can occur if the ACOT is to be included in the following year's prices. The calculation of the amount via "but for" solves of the transmission pricing methodology will probably have to occur in December, as Transpower does not have the final audited information from the previous pricing capacity measurement period before mid-November. This will leave the Commission just a few weeks in December in which to make its decision. Any delay beyond December would make it very difficult for EDBs to include the pre-approved amounts in their prices for the following pricing year, as these are published in January. We are currently investigating other alternatives that would facilitate timely inclusion of the ACOT amount in EDBs' annual pricing while minimising the administrative effort required by EDBs and the Commission. We will discuss these further in our 29 August submissions.

90. The proposed approach to calculating ACOT (counterfactual running of the TPM) also creates some uncertainty because the future form of the TPM is currently uncertain. The TPM has been under active review by the Electricity Authority since 2012, and this review appears unlikely to be completed before late 2015 at the earliest. We also note that, at present, the input methodologies (IMs) require ACOT to be equivalent to a charge under the TPM or a new investment contract and it is not clear if the proposed amendments to the IMs will allow the new calculation method to be applied. We comment further on this point in response to the relevant IM drafting consultation.

91. We would appreciate further clarification by the Commission of whether or not purchases of assets after the start of the regulatory period will be included in the capex IRIS calculations. Attachment D of the proposed default price-quality path for EDBs from 1 April 2015 states specifically12 that no capex allowance will be provided for forecast additional expenditure for assets purchased from Transpower after the start of the regulatory period. Instead, the Commission will rely on the incentive mechanism applying to asset transfers.. We are concerned that not providing any provision in the capex allowance in this way could cause complications for the capex IRIS calculations if

[12] *Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015*, Commerce Commission para. D33.

transmission asset transactions are not clearly excluded from the capex IRIS calculations.

92. We note that the IRIS amendments (draft IRIS IM amendments 2014) for capex consider the variance between—

– "forecast aggregate value of commissioned assets" meaning, in effect, the value of forecast capital expenditure; and

– the sum of the actual "value of commissioned assets".

93. Both terms are defined in the current input methodologies, but neither definition excludes purchases from Transpower.

94. The additional capital expenditure allowance allows for additional capex forecast for transmission assets purchased in 2015 to be included in the reset calculations and offset by a recoverable cost if the transfer does not take place. The additional allowance is permitted only if:

– the capex forecast is consistent with any known Transpower forecasts of capex on those assets over the regulatory period; and

– the calculation of the avoided cost of transmission charge does not include a provision for the additional capex.

95. It is not clear how EDBs would prove that the additional capex forecast is consistent with "any known" Transpower forecast. Clarification of this point would be appreciated. "Known" could be taken to mean included in Transpower's annual report or, possibly, its individual price-quality path proposal. However, the capex plans in Transpower's annual report are not particularly precise.

96. Another issue relevant to forecast additional capex requirements related to purchased Transpower assets is that EDBs often purchase these assets to support the security of their own networks. This frequently requires immediate capital expenditure to achieve this objective. As Transpower's investment view is different from that of the EDBs, it would be very unlikely that Transpower would have forecast the need for such additional capex. Hence, when assessing some potential purchases of Transpower assets, EDBs will need to take account of a further capital cost that will not be acknowledged by the price-quality path reset.

9. Energy efficiency and demand-side management incentives

97. The Commission's proposals are consistent with the recommendations made by the ENA working group paper, which Powerco supports. The framework being developed will help accommodate energy efficiency and demand-side management initiatives but will not incentivise them to any significant degree. In our submission on the Commission's 30 April 2014 Process and Issues paper we provided examples of where clarification would be helpful with respect to the application of the definition of "electricity lines services" to particular energy efficiency and demand-side management initiatives. We appreciate the Commission's awareness of this issue.

98. Powerco continues to invest to support demand side efficiency through ripple hot water control. As technology and consumer preferences change the Commission's proposals will help to remove disincentives to consider new alternatives to support demand side management and energy efficiency. The mechanism proposed is pragmatic and can be expected to be cost effective (though this will be tested by practical application). The

approach adopted should assist work to pilot and grow emerging opportunities for consumers, the results of which are often highly uncertain when compared to conventional network investment.

99. We note the changes proposed do not provide strong incentives to substantially increase the level of investment in demand side management and energy efficiency. Section 54Q of the Commerce Act requires both the removal of disincentives and the use of incentives. Faced with two relatively comparable outcomes, without strong incentives to pursue riskier and less certain new demand side management or energy efficiency investments, EDBs can be expected to adopt the commercially safer option of investing in technologies which have a proven track record of meeting consumer needs.

9.1. Exclusion of tariff-based incentives

100. Clauses 9(a) and 10 of the Electricity Distribution Services Default Price-Quality Path Draft Determination 2015 state:

> 9. The application for approval must include:
>
> (a) a detailed description of the energy efficiency initiative or demand-side management initiative, excluding any initiative that is primarily tariff-based, for which the EDB seeks an Energy Efficiency and Demand Incentive Allowance;
>
> 10. The Commission may approve, by notice in writing to the Non-exempt EDB, an amount equal to the foregone revenue in the Assessment Period, as determined by the Commission, directly attributable to an energy efficiency initiative or a demand-side management initiative commenced during the Regulatory Period in which the Assessment Period occurred, but excluding any initiative that is primarily tariff-based, such as time-of-use pricing. [emphasis added]

101. We believe the exclusion of tariff-based initiatives, such as time of use pricing, from the initiatives that may potentially benefit from an Energy Efficiency and Demand Incentive Allowance is counter-productive and possibly inconsistent with the intention of section 59Q. Tariff-based initiatives provide some of the most powerful energy efficiency incentives. The proposed exclusion will dis-incentivise tariff adjustments that may promote energy efficiency and provide a net benefit to consumers and the nation as a whole, but which would have a negative effect on an EDB's revenue. We recommend that that the Commission amend the proposal to enable it to consider tariff-based energy efficiency proposals on a case by case basis.

102. We will comment further on this point in our submission on the draft DPP determination.

9.2. Conclusion

103. In summary, we support the energy efficiency and demand-side management proposals as appropriate and pragmatic in the current context, apart from the exclusion of tariff-based incentives, but anticipate that further initiatives under section 54Q may be required in the future.

10. Computational Issues

10.1. Calculation of input data for Model 4: forecast capital expenditure

104. We have identified an error in the way in which the Commission has calculated Powerco's historical network capex value for 2011.

105. We have previously pointed out that our 2011 information disclosure values did not include any capex that one of Powerco's subsidiaries (ITS Limited) incurred during that year. Following discussions with the Commission in 2012 we began to include ITS capex in our disclosures from 2012 onwards. Please refer to the following correspondence:

- 3 May 2012 letter from Richard Fletcher to Alex Sim; and
- 2 July 2012 letter from Alex Sim to Richard Fletcher.

106. The Commission has not adjusted for this capex spend to derive an appropriate 2011 base capex. ITS Limited has now been amalgamated into Powerco Limited and any work that ITS Limited would typically done is now being undertaken by Powerco, including 2 major grid exit point developments in the Eastern region included in our 2014 AMP capex in 2015/16 and 2016/17.

107. We believe it is incorrect to not include the ITS capex in the 2011 calculation when this form of capex is part of our allowance in the next regulatory period. We therefore propose that our 2011 base year capex should be as follows:

Description	$000	Source
Historical Network Capex 2011 (nominal)	76,829	2011 ID Accounts
ITS Adjustment	4,146	12 November 2012 Electricity DPP Starting Price Adjustment: Certified Information
Corrected Historical Network Capex 2011 (nominal)	80,975	

108. We are happy to provide further information on this issue if required.

10.2. Incorrect indexation of disposals

109. The modelling includes an error in the conversion of nominal dollars to real 2012/13 dollars. This was raised prior to the Question and Answer session for Electricity DPP Draft Decision Models on 25 July 2014and the Commission has accepted a correction will be made to the calculation.