Aurora
ENERGY LIMITED

Submission

Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015

and

Low Cost Forecasting Approaches for Default Price-Quality Paths

15 August 2014

DELTA
THINK.INFRASTRUCTURE

PREPARED FOR AURORA ENERGY LTD
BY DELTA UTILITY SERVICES LTD

Telarc SAI registered
ISO 9001

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY 1
2 INTRODUCTION 4
3 AURORA SUPPORTS THE COMMISSION'S PERFORMANCE 5
4 REASONABLE INVESTOR EXPECTATIONS 8
5 ENSURING DECISIONS ARE EVIDENCE BASED 9
6 2013/14 IS THE RELEVANT BASE YEAR FOR OPEX 12
7 LIMITS ON HISTORICAL CAPEX 20
8 PARTIAL PRODUCTIVITY 25
9 CONSTANT PRICE REVENUE GROWTH FORECASTING 28
10 REVENUE-LINKED SERVICE QUALITY SCHEME 30
11 WASH-UP PASS-THROUGH AND RECOVERABLE COSTS 38
12 CUSTOMISED PRICE-QUALITY PATHS 44
13 NEXT STEPS 45
14 POST-RESET PRIORITY WORK AREAS 47

1 EXECUTIVE SUMMARY

Aurora believes that the Commerce Commission is fundamentally doing a good job of operating Part 4 of the Commerce Act.

We recognise the challenges that the Commission faced in developing a new price control regime (with the move from Part 4A to Part 4) in a short period of time. Operation of Part 4 is still in a transition phase.

Aurora remains in agreement with the fundamental elements of the Commission's operation of Part 4 of the Commerce Act and that, in broad terms, it is consistent with the purpose of Part 4.[1]

We consider that the Commission's proposals include a number of substantive improvements to the operation of the DPP regime, which will better promote the long-term interests of consumers.[2]

We are pleased to see that the Commission recognises there is plenty of room to improve on the initial DPP resets, and for the regime to evolve. It would have been a mistake if the Commission had treated this reset process simply as a 'crank the handle' exercise, based on the initial resets. We are supportive of most of the Commission's initiatives to improve the regime; particularly the heightened focus on incentives to improve efficiency and service quality.

It was understandable that the initial reset was implementation focussed and prioritised what was necessary for a reset (e.g. forecasting), rather than what was desirable (e.g. adoption of efficiency incentive mechanisms).

There are, nevertheless, areas of concern. Some of these concerns have the potential to undo much of the good work that the Commission is otherwise doing. We are particularly concerned that the proposed reset will not adequately take account of our increased opex and capex commitments, much of which are targeted at ensuring service quality and safety; e.g., vegetation maintenance and pole replacement. Continued reliance on NZIER regional GDP forecasts could also repeat the overstatement (by 100% for Aurora in the last reset) of revenue growth in the DPP model.

Not all of the Commission's DPP proposals are adequately evidence based and this creates risk of downward bias in price setting

We are concerned that the Commission is making a number of judgements that lack adequate evidential basis, and could unduly result in lower prices. We observe that similar comments have been made by submitters in respect of the Commission's consultation on the TSLRIC price determinations for UBA and UCLL, albeit that the impact is the opposite (higher prices, not lower).

For example, in relation to opex base year selection; the limit on capex and the partial productivity factor:

- **Opex base year:** The Commission has provided no valid evidence that 2013/14 is an atypical year, and no evidence at all that EDBs have gamed the regime by inflating their 2013/14 opex. The evidence Aurora provides in this submission suggests forecast opex reflects the general upward trend in opex and typical year-on-year cost volatility.
- **Capex limit:** The Commission assumes the use of capex forecasts provided by distributors has provided distributors with incentives "to systematically bias their forecast to increase their starting price"[3] and, despite this being based solely on the accuracy of EDBs' forecast

[1] Aurora Energy, Submission to the Commerce Commission on its Draft Decisions Paper (July 2011) on 2010-15 Default Price Quality Path for Electricity Distribution, 24 August 2011, page 4.

[2] The areas we consider the Commission should prioritise for the post-2015 resets are detailed in: Appendix: Priority work areas for post 2015 resets.

[3] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 4.14.1.

of network capital expenditure in one year,[4] the Commission relies on this as a basis for limiting the capex of all EDBs that have materially over-forecast capex to 110% of the historic average, rather than 120%.

The proposed reset also fails to recognise that the Commission's own advisor, Strata, has confirmed that Aurora needs to continue to increase opex/capex compared to previous years to ensure our service quality performance standards are met. There seems to be a disjoint between the Commission's compliance monitoring/enforcement and DPP reset.

The Commission should recognise that we are substantially reducing dividend payments to help fund increased capex. This has been agreed by the Board and Dunedin City Holdings Ltd (DCHL) and is on public record.

When the Commission is making judgements about what capex/opex should be provided for in the reset, it should be evaluating AMP information/and information it knows.

- **Partial Productivity Factor:** The Commission provides no evidence that the negative productivity factor is temporary, or why EDB submissions that explain why this may be enduring are incorrect.

This is particularly disappointing, as a clear message from the High Court Part 4 IM Merit Appeal decision is that the Commission's decisions should be evidence-based to the extent practicable.

Factors that could exacerbate reset problems

We are also concerned that there may be a repeat of flawed regional GDP growth assumptions that likely contributed to Aurora's constant price revenue growth being forecast too high at the last reset. We do not consider it plausible that the regional growth rate for Aurora's network area should be second only to the Auckland region.

The Commission forecast constant price revenue growth for Aurora, at the last reset, to be 0.6% which is double the actual constant price revenue growth of 0.3% for 2010-14. Constant price revenue growth should be based on historic trend.

The Commission's proposal to reduce the WACC percentile from 75th to 67th, regardless of its merit, will compound any problems with the Commission under-specifying EDB future opex/capex and/or over-specifying future revenues.

These concerns could also be exacerbated by the service quality reset method which results in an upward ratcheting of service quality requirements.[5] EDBs get penalised for breach (potential non-compliance penalties) and for outperforming service quality requirements (more arduous future requirements). There is also a perverse outcome whereby if the service quality requirements are exceeded in two consecutive years it is a breach, and the service quality reset method will treat these two years as if performance equalled the standard, but if the requirements were exceeded on non-consecutive years actual service quality for those two years would be used to determine the service quality standards for the next reset.

Aurora commitment to significant opex and capex increases

Aurora has committed to significant opex and capex increases for both reliability and demand growth that should be reflected in the DPP. We have agreement with our Board and shareholder, DCHL, to reduce dividend payments by $2 million per annum to, in part, fund this. We can confirm this with Board Meeting minutes, revised Statement of Intent etc.:

[4] Or 2012 if the forecast was revised for the purpose of the 2012 reset.

[5] Refer to: Section 10 – Revenue-linked service quality scheme.

- Vegetation management budgeted expenditure is $4.3 million per annum for the years ending 2015 – 2018, then $4.1 million per annum for years ending 2019-2024. This opex has been agreed and committed to by the Board. This is an additional $3m in total for the 2015-2020 DPP period;
- Budgeted expenditure on pole replacements is $4 million for the current year ending 31 March 2015, over both the Dunedin and Central Otago networks;
- $20 million has been approved in principle, for upgrade of SCADA, Control, Communications and Protection systems (SCCP). The SCCP programme consists of eight interrelated projects that will modernise and integrate our network management, control and communications systems. The $20 million will be approved and committed in discreet components.
- $4.5 million of the SCCP has been committed and agreed by the Board so far;
- $6 million is about to be committed to build a new Neville Street substation over the 2015 and 2016 periods;
- $4.8 million has been agreed and committed to build a new Lindis Crossing substation over the 2015 and 2016 periods;
- $4.5 million has been agreed and committed to build a new Camp Hill substation (Wanaka) in 2015;
- consent has been granted for a new $4 million Riverbank Road substation (Wanaka); and
- Aurora will cut dividends by $2 million per annum, from $9.5 million to $7.5 million, from 2015/16.

The capex and dividend changes are reflected in Aurora's Statement of Intent 2014/15 as summarised in Table 1 below:

Financial Year Ending 30 June	2015	2016	2017
Capital expenditure ($000)	32,948	34,624	24,249
Dividends/subvention ($000)	9,500	7,500	7,500

Table 1: Statement of Intent 2014/15 Projections

A good start … but more work needs to be done to get the DPP resets right

Aurora considers that the Commission has done a good job in progressing incentive mechanisms, and various other refinements, for the DPP reset. We are less comfortable that the Commission has ensured that the price paths it is proposing are free from systematic error, meet "reasonable investor expectations", or adequately reflect the uplift in our opex/capex such that we can have confidence that the reset will provide a reasonable expectation of, at least, a normal return on capital.

There will be further scope for improvement and evolution in subsequent resets; particularly as there will be a full five years between the next two EDB DPP resets. The Commission has been constrained, this time around, by the two-year period between the first two EDB DPP resets, with the first gas reset in the intervening period.

2 INTRODUCTION

Aurora Energy is pleased to submit on the Commerce Commission's "Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015", and "Low Cost Forecasting Approaches for Default Price-Quality Paths", 4 July 2014. We support the submissions of the ENA and PricewaterhouseCoopers on this matter.

Where relevant, we make reference to the following companion documents:

- Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014;
- Proposed Quality Targets and Incentives for Default Price-Quality Path From 1 April 2015, 18 July 2014;
- Proposed amendments to Input Methodologies for Energy Distribution Services, 18 July 2014; and
- Proposed amendments to input methodologies: Incremental Rolling Incentive Scheme, 18 July 2014.

No part of our submission is confidential and we are happy for it to be publicly released.

If the Commission has any queries regarding this submission, please do not hesitate to contact Alec Findlater:

Alec Findlater
Commercial Manager
Delta Utility Services
alec.findlater@thinkdelta.co.nz
(03) 479 6695
(027) 222 2169

3 AURORA SUPPORTS THE COMMISSION'S PERFORMANCE

Aurora considers that the Commission is doing a commendable job, and we are generally pleased with the way Part 4 is evolving

Aurora recognises the challenges that the Commission faces in undertaking the DPP resets. The Commission had to develop a new/expanded Part 4 price control regime for electricity, gas and airports (information disclosure only), following a substantial overhaul of the Commerce Act and replacement of Parts 4 and 4A with a new Part 4. The Commission needed to do this under extremely tight timeframes. Even after the first resets, the Commission is still operating in a transition phase as it has to make some changes to reflect the outcome of appeals of its decisions to the High Court,[6] and there is only two years between the first reset and the second for electricity distribution.[7]

The Commission has also faced additional challenges due to the judicial reviews and merit appeals of its decisions that occurred while it was still implementing the new Part 4 regime, and now has to undertake TSLRIC determinations for Chorus' UBA and UCLL services under Part 2 of the Telecommunications Act, for the first time, in parallel with the EDB DPP resets.

Our impression, although to our knowledge the Commission has never been overt about this, is that the first resets reflected a focus on what needed to be done to enable the resets within very tight timeframes, as opposed to what should ideally be included as part of the resets. We assume this is why mechanisms such as an IRIS, service quality-revenue linkages, and specific section 54Q mechanisms weren't features of the initial DPP resets, but are reflected in the current reset proposals.

The Commission is making significant improvements, despite the tight timeframe between the initial and second EDB DPP resets

The Commission's proposed DPP reset makes a number of significant improvements, which we welcome. This is consistent with Aurora's view that the Commission's approach in the initial reset, while appropriate at the time, "needs to be further reviewed and tested and refined at the next regulatory determination in 2014".[8] Examples of aspects of the proposed DPP reset where we consider improvements are being made include, but aren't necessarily limited to:

- **Efficiency incentives:** Aurora supports the introduction of an IRIS and mechanisms to smooth incentives over the five year regulatory period. We caution, though, that the benefits of an IRIS will be reduced if the opex forecasts the Commission uses understate actual (efficient) opex requirements[9] (how much depends on the change in retention factor under the IRIS). We also agree "that it is necessary to specify the retention factor used in the next regulatory period so that suppliers and consumers know the retention factor that will apply before expenditure is incurred".[10]

---

[6] Though most of these were rejected.

[7] Given time constraints meant that the Commission initially rolled over existing prices at the start of the 2010 DPP regulatory period, and then undertook a mid-period reset in 2013.

[8] Aurora Energy, Submission to the Commerce Commission on its Update Paper on 2010-15 Default Price Quality Path Starting Price Adjustment and Other Amendments, 16 May 2011, page 10.

[9] Aurora is concerned the approach the Commission proposes to take to determining opex will understate our, and most other EDBs', opex requirements and efficient opex over the forecast amount will be treated as an "inefficiency" under the IRIS and we will be penalised for five years, rather than to the end of the regulatory period (2020) as would be the case under the current arrangements.

Refer to: Section 6 2013/14 is the relevant base year for opex.

[10] Commerce Commission, Proposed amendments to input methodologies: Incremental Rolling Incentive Scheme, 18 July 2014, paragraph 156.

- **Revenue-linked service quality scheme:** Aurora is pleased that the Commission has adopted our previous recommendation that service quality and price be linked,[11] Adoption of a revenue-linked service quality scheme by way of recoverable cost would appear to be a pragmatic solution.[12]

- **Section 54Q:** While Aurora does not consider it as important as general efficiency and service quality incentives, we also support the introduction of specific section 54Q mechanisms, with the adoption of "compensation for foregone revenue resulting from an energy efficiency or demand side management initiative" as a new recoverable cost. The introduction of stronger general efficiency incentives should also help to better achieve the purpose of section 54Q, where adoption of energy efficiency initiatives are efficient.

  The requirement that recovery "of revenue foregone as a result of energy efficiency and demand side management initiatives must be submitted at the same time as the annual compliance statement"[13] should help ensure consumers and other stakeholders have confidence that the s54Q mechanisms won't simply be used to cross-subsidise EDB activity in downstream competitive markets.

- **Capex wash-up:** Aurora supports adoption of "a 'wash-up' for capital expenditure in the final year of the current default price-quality path";[14]

- **Pass-through:** Aurora supports consideration of mechanisms to reduce EDB risk from over/under-estimating pass-through/recoverable costs. If dealt with appropriately this will help address Aurora's previous concern that the Commission is concerned about over-recovery, but not about under-recovery. The Commission's proposals would be a substantial improvement on existing arrangements, though our preference is for a wash-up mechanism.

- **Pass-through of AUFLS levies or charges:** Aurora supports treatment of any levy or other charges or costs associated with any automatic under-frequency load shedding (AUFLS) programme that the Electricity Authority may implement during the regulatory period as a new recoverable cost.[15] We consider inclusion of this matter is a good example of the Commission and the Electricity Authority working well together and coordinating their respective work streams.

- **Pass-through of avoided transmission charges:** We also support treatment of "indirect" transmission charges as a "pass-through like" charge;[16]

In terms of both AUFLS and avoided transmission charges we agree that it is appropriate to "require the distributor to show that the amount was calculated in accordance with any regulation made by the Electricity Authority under the Electricity Industry Act 2010".[17]

---

[11] Aurora Energy, Submission to the Commerce Commission on its Discussion Paper on Starting Price Adjustments for Default Price-Quality Paths, 10 September 2010, page 16.

[12] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.30.1.

[13] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.68.

[14] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.30.3.

[15] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.75.2.

[16] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.32.

[17] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.77.

Refer to:
Ensuring ACOT payment arrangements remain practicable and are to the long-term benefit of consumers.

- **Adjusting the price path following a major transaction:** Aurora supports the Commission's proposed approach, under which "the seller and purchaser of network assets must agree the amount of allowable notional revenue attributable to the transaction, and any pass-through and recoverable costs attributable to the transaction".[18]

- **DPP re-opening:** We support opening DPPs for catastrophic events.

Aurora would also like to acknowledge the Commission's early release of its financial models for review and consultation. While we did not submit on this (beyond being a party to the PricewaterhouseCoopers submission), we acknowledge that the Commission has made improvements to the financial models and they are now more user-friendly.

Aurora remains of the view that the Commission's DPP price setting "promotes a relatively low cost approach compared with those in most overseas jurisdictions where the prevailing methodology – building block approach – is more detailed, EDB specific and significantly more expensive".[19]

While the Part 4 regime is becoming more sophisticated, it should be acknowledged that simplicity is not synonymous with low cost; e.g., the Part 4 regime would be simpler without an IRIS but at higher cost (to consumers) if this meant EDBs had weaker incentives to improve efficiency.

Bouquets and brickbats for the Commerce Commission

It should be clear that Aurora has a high degree of confidence in the Commission. We consider that the Commission and its staff are doing a good job in very difficult and trying circumstances. What we would like to see now is regulatory stability, to enable the Commission to move from a focus on implementation to development and evolution of the current Part 4 regime.

This includes addressing areas where we feel the Commission has not performed as well as it could. There are aspects of the Commission's proposed DPP reset which we have misgivings about and where we believe material improvements could be made; for example:

- meeting "reasonable investor expectations";

- the Commission is making a number of subjective judgements that could result in prices that are too low; for example, in relation to opex base year selection; the 110% cap on historic average capex, and the partial productivity factor. The understatement of opex could undermine the potential benefits of an IRIS, as the forecasting error will be treated as inefficient opex, with the EDB penalised for the inefficiency for five years rather than until the end of the regulatory period in 2020;

- the proposed reset does not adequately recognise that the Commission's own advisors have confirmed Aurora needs to increase its opex/capex to ensure our service quality performance standards are met;

- we are also concerned there may be a repeat of flawed regional GDP growth assumptions, that likely contributed to Aurora's constant price revenue growth being forecast too high at the last reset; and

- these concerns are exacerbated by the service quality reset method which results in an upward ratcheting of service quality requirements; EDBs get penalised for both breach (potential non-compliance penalties) and outperforming (more arduous future requirements).

[18] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 5.8.

[19] Aurora Energy, Submission to the Commerce Commission on its Update Paper on 2010-15 Default Price Quality Path Starting Price Adjustment and Other Amendments, 16 May 2011, page 9.

4 REASONABLE INVESTOR EXPECTATIONS

We question how well some aspects of the proposals reflect "reasonable investor expectations",[20] with aspects of the Commission's proposals that could result in prices that are too low. Aurora is particularly concerned that the Commission's proposals could unduly curb our opex and capex, based on a number of subjective judgements, even though the Commission's expert, Strata, has confirmed that we need to increase both in order to ensure we meet our DPP service quality performance standards, and we have made firm commitments to increases as a consequence.

We are disappointed that the DPP Reset consultation material makes no reference to "reasonable investor expectations" even though the Commission uses the principle repeatedly in its recent UBA and UCLL FPP consultation to justify making judgements that would result in substantial uplifts in Chorus' copper prices. The Commission's comments on "reasonable investor expectations" are generally applicable to any regulated supplier. Two representative quotes are:

> *"… we have decided that to help build predictability in regulation, we will respect what we see as reasonable investor expectations in relation to major … infrastructure … predictability supports investment … for the long-term benefit of end-users."*[21]
>
> *"… our intention to respect reasonable investor expectations to avoid the risk of chilling investment … when combined with … generally higher prices that may result … will best give effect to the … purpose."*[22]

A number of submissions; i.e., Telecom, Vodafone and Wigley & Company, suggested that the concept of "reasonable investor expectations" is more applicable to Part 4 of the Commerce Act than Part 2 of the Telecommunications Act.[23] For example, the purpose of the IMs makes reference to predictability and certainty, but the purpose under Part 2 of the Telecommunications Act does not.

We also note and agree with the following comments from Telecom about "reasonable investor expectations" and consider them to be equally relevant to the EDB DPP price reset:

> *"The Commission further proposes that, to help build predictability in to regulation, it will respect what it sees as reasonable investor expectations in relation to major telecommunications infrastructure and we support that principle. We agree that, at the macro level, the regulatory framework should be predictable … Predictability and certainty are important for investors in both Access Seekers and Chorus, and for consumers."*[24]
>
> *"We consider that reasonable investor expectations are that they will receive a normal return over the life of assets …"*[25]

---

[20] A term that is used extensively in the Commission's current consultation on the Chorus' UBA and UCLL TSLRIC pricing determinations, but not at all in relation to the electricity DPP resets.

[21] Commerce Commission, Consultation paper outlining our proposed view on regulatory framework and modelling approach for UBA and UCLL services, 9 July 2014, paragraph 80.

[22] Commerce Commission, Consultation paper outlining our proposed view on regulatory framework and modelling approach for UBA and UCLL services, 9 July 2014, paragraph 86.

[23] Refer to: Submissions on Regulatory framework and modelling approach consultation paper at http://comcom.govt.nz/regulated-industries/telecommunications/regulated-services/standard-terms-determinations/unbundled-copper-local-loop-and-unbundled-bitstream-access-services-final-pricing-principle/

[24] Telecom, UCLL and UBA FPP: consultation on regulatory framework and modelling approach, 6 August 2014, paragraph 79.

[25] Telecom, UCLL and UBA FPP: consultation on regulatory framework and modelling approach, 6 August 2014, paragraph 85.

5 ENSURING DECISIONS ARE EVIDENCE BASED

One of the lessons we took from the High Court Merit Appeal decision was the importance of ensuring evidence-based decisions.

For example, a couple of representative statements from the High Court on the matter of evidential requirements were:

> *"Vector's failure to provide any evidential explanation … is a major weakness in its argument."*[26]

> *"Where a proposition is simply asserted by economic experts, we give it little or no weight."*[27]

These statements hold as valid whether it is a submitter or the Commission that has simply asserted a proposition, or has failed to provide any evidential explanation.

The RAB and WACC percentile challenges are also specific examples where the outcomes turned on the evidence, or lack thereof.

The RAB challenge was based on the argument that the RAB IMs would result in below cost asset valuations and this would have a deleterious impact on incentives to invest. While the RAB IMs had a significant degree of arbitrariness to them, which the Commission described as taking a "line in the sand", the case against the Commission fell down largely because no evidence was provided that the RAB IMs produced asset valuations that were below cost.

The High Court agreed with the Commission that:

> *"Upward revaluation might be warranted if: … EDBs and GPBs were able to demonstrate that prices set on the basis of existing regulatory valuations would prevent them from earning at least a normal return relative to the original costs of their investments before profits appeared excessive. They have not done so. Existing valuations are therefore consistent with EDBs and GPBs having appropriate incentives to invest …"*[28]

The High Court reached the following conclusions in relation to RAB:

> *"… we are not prepared to assume … that regulated suppliers have, in fact, suffered accounting losses to date."*[29]

> *"… no regulated supplier – other than Vector whose evidence we did not find persuasive – provided factual evidence to suggest that the initial RAB values were such that over the lifetime of the assets the suppliers would in fact earn less than normal returns … like the Commission we think that is of considerable significance."*[30]

> *"The Commission had … the reasonable understanding that the 2009 regulatory valuations were sufficiently high for regulated suppliers to earn at least a normal return on capital for past investments. That understanding had been confirmed by the lack of evidence from suppliers that that would not be the case."*[31]

Similarly, the High Court view on the WACC percentile matter, that inadequate evidence had been provided to justify 50th percentile, 75th percentile (the status quo) or higher:

> *"No supporting evidence was provided by the Commission. Indeed, the propositions advanced … seemed to be considered almost axiomatic."*[32]

---

[26] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013], paragraph [1513].

[27] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013], paragraph [1745].

[28] Commerce Commission, Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper, December 2010, paragraph 4.3.65.

[29] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013, paragraph [588].

[30] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013], paragraph [589].

[31] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013], paragraph [638].

[32] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013], paragraph [1462].

> *"These in-principle objections to deliberately erring on the side of overestimating the WACC, however, suffer from the same lack of empirical support, at least in the materials before us, as the Commission's approach.*
>
> *The onus is on MEUG to persuade us that applying a mid-point WACC estimate would lead to a materially better IM. While MEUG's in-principle arguments cast significant doubt on the Commission's position, it did not present any positive evidence of the type we refer to above, for example an inter-sectorial analysis, in support of its proposal. We are therefore unable to be satisfied that the IM amended as MEUG proposes would be materially better in meeting the purpose of Part 4 and/or the purpose in s 52R."*[33]

It is disappointing, therefore, that material aspects of the Commission's DPP determination are based on assumption and judgement, and not adequately supported by evidence. (We note similar comment has been made in submissions on the Commission's TSLRIC price determinations for UBA and UCLL services[34]).

The lack of evidential support includes; the proposals for selection of the base year for opex,[35] the 110% cap penalty for capex on EDBs that had over-forecast their capex,[36] and determination of a partial opex productivity factor.[37] Each of these examples is discussed in more detail in subsequent sections, but in summary we would note:

- **Opex base year:** The Commission has asserted that EDBs' forecasts of 2013/14 opex suggest that the opex for that year is "atypical"[38] and that distributors "may have" had incentives to 'game' the base year (by advancing or deferring expenditure).[39] The only evidence that the Commission presented to support this was that the forecast opex was 6% higher than the historic average,[40] and reference to prima facie evidence from Castalia that UK distributors may have gamed the base year.[41]
- **Capex limit:** The Commission assumes that the use of EDBs' capex forecasts has provided EDBs with incentives "to systematically bias their forecast to increase their starting price"[42], but bases this solely on the accuracy of EDBs' forecast of network capital expenditure in one year.[43]

  To properly test for systematic bias, the Commission would need to review AMP forecasts against actual based on all available AMP data, including testing whether: (i) there is a difference in accuracy pre and post Part 4 (which you would expect if the Commission's gaming assumption is correct); (ii) the accuracy of the Commission's forecasts versus that of distributors; and (iii) whether other patterns may better explain the inaccuracies; e.g., the forecast error becomes progressively worse the longer out the project, or that small EDBs are less accurate than large EDBs. At present the Commission has tested the hypothesis based on a single set of data.

[33] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013], paragraphs [1482] and [1483].

[34] Refer to: Submissions on Regulatory framework and modelling approach consultation paper at http://comcom.govt.nz/regulated-industries/telecommunications/regulated-services/standard-terms-determinations/unbundled-copper-local-loop-and-unbundled-bitstream-access-services-final-pricing-principle/

[35] Refer to: Section 6 2013/14 is the relevant base year for opex.

[36] Refer to: Section 7 Limits on historical capex.

[37] Refer to: Section 8 Partial productivity.

[38] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph A.14.1.

[39] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 3.11.2.

[40] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, Figure 3.1.

[41] Commerce Commission, Proposed amendments to input methodologies: Incremental Rolling Incentive Scheme, 18 July 2014, paragraph 30.

[42] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 4.14.1.

[43] Or 2012 if the forecast was revised for the purpose of the 2012 reset.

- **Partial opex productivity:** The Commission has proposed "to assume that partial productivity for operating expenditure will not change over the upcoming regulatory period".[44] This assumption is based solely on the recommendation of Economic Insights. Economic Insights' empirical evidence is that total factor productivity (TFP) since 2004 has been -1% and their view is that "a significant change in market conditions facing the energy supply industry occurred around 2007 with significantly reduced growth rate in demand which has now lasted for 6 years" and "This change has been observed in Australia, Canada and the US". Despite this evidence, Economic Insights claim "an estimated TFP growth rate of zero" on the basis that "there is … some expectation from experts … that positive electricity demand growth will resume" (emphasis added) and "This is likely to contribute to a return to a positive TFP growth … in the medium term".[45]

  Just as the High Court deemed it wasn't adequate to base a decision on WACC percentile purely on judgement, and the decision should be evidence based, we would expect the same standards to be applied in the Commission's Part 4 decision making more generally.

[44] Commerce Commission, Proposed Default Price-Quality Paths For Electricity Distributors From 1 April 2015, 4 July 2014, paragraph C18.

[45] Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2013, 24 June 2014, pages iii and iv.

6 2013/14 IS THE RELEVANT BASE YEAR FOR OPEX

The Commission should adopt 2013/14 as the base year for opex.

Aurora has previously stated "In general, Aurora supports the principle that EDB-specific data be used to the maximum extent possible for projecting future costs and revenue in the regulatory period. This will improve the accuracy of the regulatory process and its outcome." This is why Aurora supported the use of 2009/10 data for the first reset "being the latest year before the start of the regulatory period for which data is available".[46]

Aurora considers that the only potentially valid grounds for the Commission to consider use of anything other than the most recent opex data; i.e., use of 2012/13 data as well as, or instead of, 2013/14 data for the 2015 reset would be if the Commission:

- had evidence that 2012/13 opex would be more reflective of 2015-2020 opex requirements than 2013/14 opex (see discussion below); and/or
- wanted to use two years data to help address year on year cost volatility.[47]

The latter had been raised as an option by some regulated suppliers, but taking an average of two years opex data when opex is increasing will also result in an understatement of opex. A multi-year average is only suitable when there is no evidence or reason to expect one year's costs to be higher/lower than the other(s).

The Commission provided two reasons why the Commission considers "it may be inappropriate to give much weight to date for 2014";[48] 2013/14 being an "atypical" year, and EDBs gaming the opex base year. Both arguments fit under the criteria of determining which year opex data would be most reflective of 2015-2020 opex.

2013/14 is not an "atypical" year for opex

The Commission first suggests "Atypically high or inefficient costs in 2014 may lead to a forecast biased in favour of the distributors and, by the same reasoning, an atypically low cost year may bias the forecast to the disadvantage of distributors".[49] As with Powerco, we are "not aware of any reason for 2014 to be atypical".[50]

---

[46] Aurora Energy, Submission to the Commerce Commission on its Draft Decision Paper (July 2011) on 2010-15 Default Price Quality Path for Electricity Distribution, 24 August 2011, page 14.

[47] There may be advantages in terms of smoothing/increasing efficiency incentives if the base year is known in advance.

Aurora considers Vector's analysis of the impact of different base year options is a good starting point for considering how to select the base year for opex for future resets (not 2015). Refer to: Vector, Submission to the Commerce Commission on Incentives for Suppliers to Control Expenditure During a Regulatory Period, 21 October 2013, paragraph 15c. Refer also to: Vector, Efficiency impacts of operation of Part 4 – Stylised Example Mark II", 21 October 2013,

Vector's analysis demonstrated that:

- Adoption of an older base year, <u>if known by regulated suppliers in advance</u>, can increase the incentives for regulated suppliers to improve efficiency i.e. if the base year is known to be year 3 (4) of the regulatory period, regulated suppliers will know they can retain efficiency gains made in year 4 (5) for 7 (6) years.
- Expanding the number of years, by including older years, in the base year, again <u>if known by regulated suppliers in advance</u>, can both increase and flatten incentives for regulated suppliers to improve efficiency.

In terms of the Commission's current consideration of whether to use Year 3 (2012/13) or Year 4 (2013/14) as the base yearbase year the highlighted benefits of using an older base yearbase year (higher efficiency incentives) and/or a longer base yearbase year (reduced gaming risk and flatter/higher efficiency incentives) would only be realised if regulated suppliers know what the base yearbase year will be prior to the actual base yearbase year. As the Commission has stated "incentive mechanisms only provide benefits to consumers when they have been signalled to suppliers up front. That is not the case for any efficiency gains that were achieved prior to the start of this regulatory period" [Commerce Commission, Revised Draft Reset of the 2010-15 Default Price-Quality Paths, 21 August 2012, paragraph 156].

[48] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 3.11.

[49] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 3.11.1.

[50] Powerco, Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper, 30 April 2014, paragraph 13.

The Commission has provided no valid evidence or reasons to suggest 2013/14 opex is “atypical” or reflects anything other than normal year-on-year variation, and the upward trend in opex. An examination of historic opex (2008 to 2012) clearly shows that 2013/14 is not atypical, and simply reflects an upward trend in opex.

The only evidence that the Commission provided was that EDBs’ estimated 2013/14 opex was higher, for most EDBs, than 2012/13 opex, and 6% higher than the historic average. It is notable that the majority of EDBs disclosed estimated opex either below (4 EDBs) or within 5% (5) of 2012/13 opex.[51]

The aggregate total opex for all non-exempt EDBs (excluding Orion) increased by 22% between 2008 and 2012, with an 8% increase between 2011 and 2012 alone. The average annual increase in total opex is 5.5% (in nominal terms) between 2008 and 2012. This is depicted in Figure 1 below. Figure 1 shows that total opex grew on average individually, and across all EDBs in aggregate.[52]

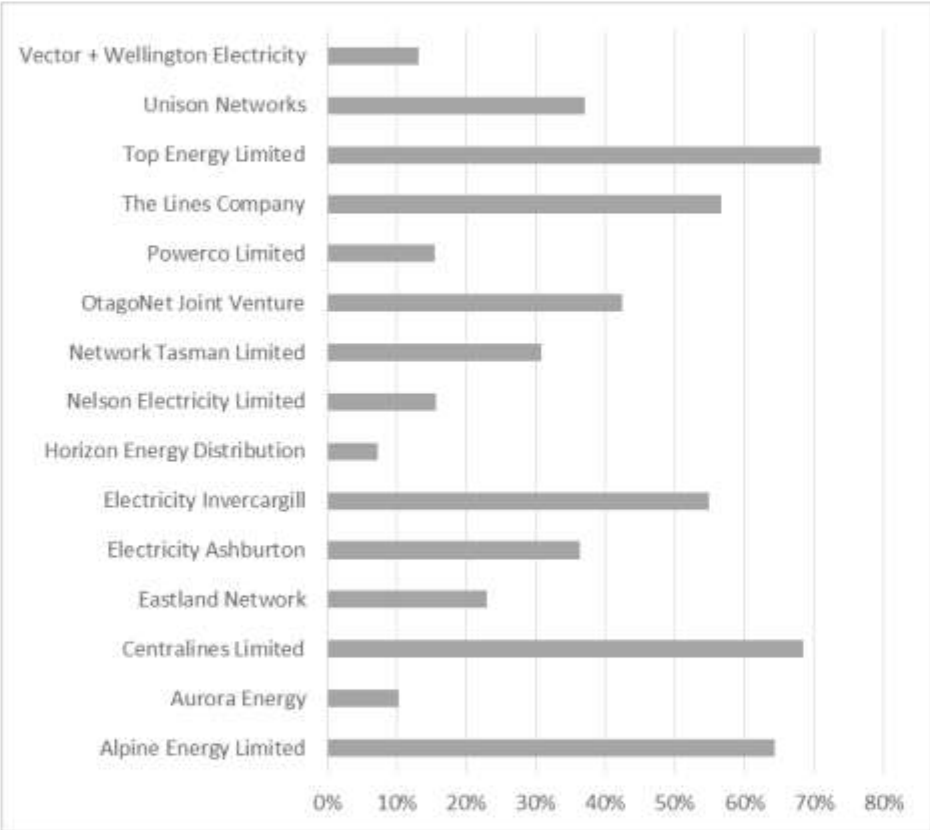

Figure 1: Change in total opex between 2008 and 2012

A review of DPP opex for 2010 – 2014 tells a similar story.[53] Between 2010 and 2014, DPP opex has increased by 20.4% or 5.1% per annum. If the 2014 forecast DPP opex is excluded, the annual increase is 4.8%. Based on this information, Aurora does not see anything unusual about forecast opex being 6% higher than the historic average.[54]

[51] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, Figure 3.1.

[52] Vector and Wellington Electricity are combined as the sale of Wellington Electricity by Vector distorts both their opex statistics i.e. Vector’s opex declines from 2008 and 2009, while Wellington Electricity has zero opex in 2008.

[53] Various adjustments are made from total opex disclosed as part of the Information Disclosure Requirements and the opex used in the DPP; e.g., removal of pass-through costs.

[54] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph A.16.

Figure 2 shows the increase in DPP opex between 2010 and 2014 – it further highlights that opex is trending upwards.

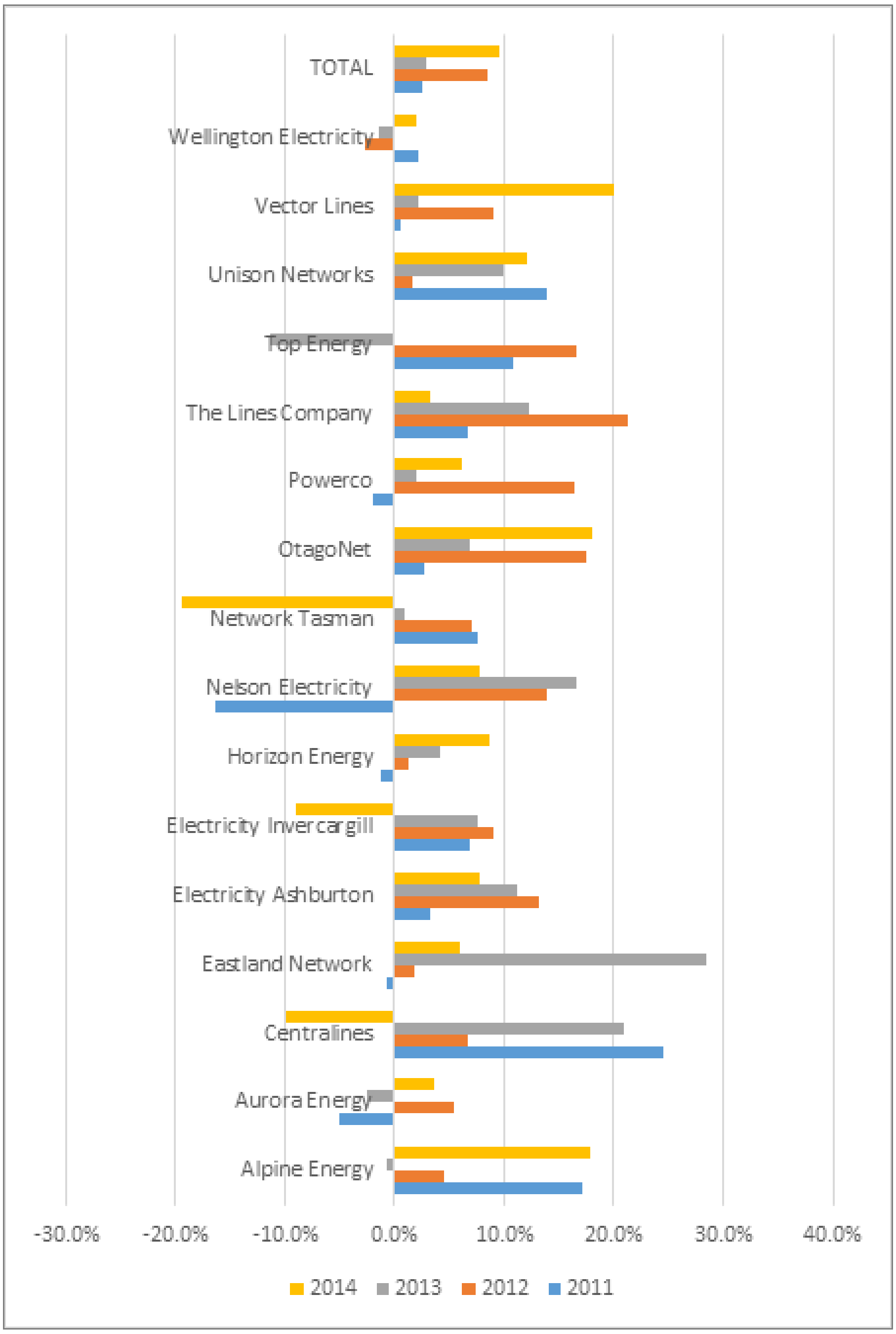

Figure 2: Annual change in DPP opex from 2010 to 2014

There is no evidence of EDBs gaming the base year

The Commission also asserts "In November 2012, we relied on the most recently available year of data prior to the start of the regulatory period, which may have created an adverse incentive for distributors to advance or defer expenditure to 2014 (or to find some other way to inflate costs in that year".[55]

[55] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 3.11.2.

Again, the Commission has not provided evidence that any EDB had delayed expenditure, or brought expenditure forward, to 2014.[56] The Commission has cited only prima facie evidence from Castalia that this may be an issue with UK distributors' opex.[57,58]

It is worth bearing in mind that the Commission chose not to specify which year(s) would be the base year in the IMs. As Powerco has noted, "the Commission has never committed to using a single base year for the reset and has a history of varying its approaches"[59] and various submissions have advocated that the Commission consider using multiple years as the base year. We accordingly agree with Powerco that EDBs would not necessarily have "presumed that the Commission would use a single year".[60]

Figure 2 above, and the accompanying evidence on EDB opex trends, does not provide evidence that gaming has occurred. If gaming/loading costs into the expected base year was a real issue in New Zealand, it is not clear why 2011/12 had a 8.6% spike in opex (2011/12 would have been seen as unlikely to be the base year) followed by a smaller increase of 3% in 2012/13 (which would have been seen as a distinct possibility as base year). This just reinforces to us that the increase in opex forecast for 2013/14 reflects normal volatility, combined with the prevailing upward trend in opex.

The Commission may also be creating a problem for itself. If the Commission decides to reject year 4 as the base year for the second reset on the basis that its first reset base year decision created an expectation that year 4 would be used and this could be gamed, what happens in the third reset after the Commission has selected year 3 (or some weighted average of years 3 and 4)? Is the Commission then concerned that this would create a precedent that either year 3 or 4 may be used as the base year, and that regulated suppliers will inflate/load costs into those two years? The only obvious way the Commission could address this is by selecting the base year randomly, or selecting all years as the base year. Aurora would suggest that neither of these options is desirable, in terms of ensuring that the base year is suitable for providing an accurate forecast of opex, but that is where the logic of the Commission's reasoning would take you.

The Commission should consider why opex is trending upwards

The Commission goes on to suggest that "Because we are unable to review of the efficiency of each distributor's disclosed levels of expenditure, the weighting given to 2014 data may ultimately depend on contextual factors." The Commission provides no indication of what it means by "contextual factors".[61]

The Commission should consider why there is an upward trend in opex.

Previous submissions have provided some explanation.

Unison, for example, states that "2013/14 data reflects the most current operating environment confronting EDBs (e.g., the impacts of legislative change, local government requirements / rating approaches, and business processes)". [62]

[56] If Commission believes some EDBs are gaming the regime by deferring/bringing forward opex so it is in expected base year, it should issue s 53ZD notices requiring statutory disclosure of any decisions to defer/bring forward, regardless of whether the decisions were expressly to bring costs in the base year or not.

[57] Commerce Commission, Proposed amendments to input methodologies: Incremental Rolling Incentive Scheme, 18 July 2014, paragraph 30.

[58] Refer: Vector, Cross-submission to the Commerce Commission on Incentives for Suppliers to Control Expenditure During a Regulatory Period, 1 November 2013, page 2.

[59] Powerco, Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper, 30 April 2014, paragraph 11.

[60] Powerco, Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper, 30 April 2014, paragraph 11.

[61] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 3.15.

[62] Unison, Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper, 30 April 2014, paragraph 31c.

There have been increases in compliance costs associated with electricity distribution activity; especially in relation to health and safety. There are additional costs now relating to the level of planning and detail required to support proposed works, as well as tighter controls around traffic management for works on roads. As Chorus has noted: “Lines companies must … minimise a number of risks, including risk to their own electricity networks, and the health and safety risks for contractors undertaking the associated work. The last decade has seen the adoption of a significant number of health and safety reforms, including director liability for breaches of the Health and Safety in Employment Act 1992”.[63]

It should also be recognised that 2012/13 was a relatively benign year, weather-wise, and this was reflected in low opex. Powerco, for example, pointed out 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”.[64] Unison made similar comment: “2012/13 was a benign year from a weather perspective, with many EDBs reporting record quality performances … This had the effect of significantly reducing requirements for emergency repairs and maintenance expenditure. Of the 16 non-exempt EDBs (excluding Orion) 12 experienced substantially lower SAIDI compared to 2011 and 2012”.[65]

Aurora specific evidence of opex increases

Aurora is concerned that the proposed reset does not adequately recognise that the Commission’s own advisors have confirmed that Aurora needs to increase its opex/capex to ensure service quality performance standards are met. We consider that “reasonable investor expectations” would include the Commission accepting this additional expenditure, confirmed by its own experts, for inclusion in the DPP reset.

Aurora exceeded its SAIDI service quality performance standards in 2010/11 and 2011/12.[66]

Aurora’s post-breach review identified that increased opex/capex was needed to address this.

Aurora provided advice to Strata on 9 July 2013 that “as a result of Aurora’s budget planning process conducted in April 2013, an additional $2 million of operating expenditure has been allocated for pole remediation and vegetation management in the 2013/14 *financial* year. An additional $1 million of operational expenditure has also been forecast for each of the four financial years from 2015 to 2018 (year ending June).”[67] (The increase in vegetation management expenditure is reflected in 2014 actual vegetation management of $2.312 million, which is $1 million more than was forecast in 2013 AMP disclosures).

We also advised that “Whilst the forecast vegetation expenditure is currently shown to remain constant in real terms, we would expect to refine and revise those forecasts annually as we refine the underlying data and understand actual needs.”[68]

Vegetation management budgeted expenditure is $4.3 million per annum for years ending 2015 – 2018, then $4.1 million per annum for years ending 2019-2024. This opex has been agreed and committed to by the Board.[69]

[63] Chorus, Submission in response to the Commerce Commission’s Consultation paper outlining its proposed view on the regulatory framework and modelling approach for the UBA and UCLL services (9 July 2014), 6 August 2014, paragraph 401.

[64] Powerco, Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper, 30 April 2014, paragraph [13].

[65] Unison, Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper, 30 April 2014, paragraph 31a.

[66] Aurora Energy’s SAIDI is substantially below the industry average, including for the period where the SAIDI threshold was breached. See Aurora Energy, 2014-24 Asset Management Plan, March 2014, page 38.

[67] Letter from Grady Cameron (Chief Executive, Aurora Energy) to Paul Ware (Commerce Commission), Strata Energy Ltd Report on the Reliability Performance of Aurora Energy Ltd, 7 August 2013.

[68] iBid.

[69] Aurora would be happy to provide Board Meeting documentation to the Commerce Commission of this commitment.

The Strata Report on Aurora's reliability performance, produced for the Commission, confirmed Aurora would need to significantly increase its opex to address the service quality performance standard breaches, but also questioned whether Aurora's projected increases went far enough.[70] The Strata Report, for example, noted:

> *"the increasing trend in tree contacts is likely to have been the result of lower than necessary investment in vegetation control which is also likely to have amplified the impact of extreme weather events"*;
>
> *"the condition of some assets (mainly poles) is also likely to have contributed to the impact of extreme weather events"*;[71]
>
> *"had Aurora maintained adequate levels of vegetation management in the past and addressed the increasing incidence of equipment failure by a targeted asset replacement programme, exceeding the reliability standard limits would likely not have occurred"*;
>
> *"both the results for 2012/13 and Aurora's targets for 2013/17 suggest that Aurora's management team has implemented appropriate asset management measures to address the performance issues on the network";*[72]
>
> *"… Aurora should review their asset strategies and planned expenditure …"*[73]
>
> *"In our discussions with management, Aurora attributed this situation to: … previous cost saving initiatives in the organisation".*[74]
>
> *"On our field inspections in Central Otago we found evidence that Aurora is undertaking a significant pole replacement programme. We found that the programme was being prioritised to address the worst performing feeders first and poles that had been inspected and "red tagged". <u>It is likely that, if resourced adequately over time, this programme will address the network performance issues that have led to the performance breaches in recent years."</u>* (emphasis added)[75]
>
> *"Based on our observations … it is likely that the proposed programmes and levels of expenditure will address the network performance issues that have led to the performance breaches in recent years."*[76]
>
> *"… <u>Aurora's expenditure forecasts would seem to be far too low to deal with the backlog of assets in poor condition. Additionally, Aurora's 2013 AMP supports the view that some budgeted amounts are inadequate.</u> For example; at page 5 Aurora estimates a cost in tens of millions to address Condition 0 vegetation management areas. At page 48 the AMP states there are 6,059 current vegetation management areas that represent an immediate danger to person or property."* (emphasis added)[77]
>
> *"In terms of catch up Aurora will increase annual average expenditure on vegetation management by 27% (average actual annual expenditure 2007/08 – 2012/13 compared to forecast annual average expenditure 2013/14 to 2018/19) ($real 2013)."*[78]
>
> *"The Operations and Maintenance expenditure 10-year forecasts appear to be a CPI adjusted extrapolation of the 2013/14 values. Each of the four main categories of Operations and Maintenance expenditure increases by 2.5% each year, which means that, in real terms, the expenditure will remain level at 2013/14 values ... we found no reason to conclude that, overall the opex forecast was insufficient."*[79]

Aurora subsequently further revised its opex by an additional $3.3 million over the 2015-2020 DPP regulatory period (totalling an increase of $6.3 million).[80] This is shown in Table 2.

---

[70] Strata Energy Consultants, Report on the reliability performance of Aurora Energy Limited, Produced for The Commerce Commission, 24 June 2013.

[71] iBid, paragraph 8.

[72] iBid, paragraph 9.

[73] iBid, paragraph 13.

[74] iBid, paragraph 46.

[75] iBid, paragraph 55.

[76] iBid, paragraph 58.

[77] iBid, paragraphs 78 - 79.

[78] iBid, paragraph 89.

[79] iBid, paragraphs 98 - 100.

[80] Aurora Energy, 2014-24 Asset Management Plan, March 2014.

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Notes
Planned 2013	9,822	10,068	10,319	10,577	10,842	11,113	11,390	11,675	11,967	12,266		2013-23 AMP, Table 5.10, p.100
Additional Expenditure	2,000	1,000	1,000	1,000	1,000							Aurora Letter to ComCom, 7 August 2013
Total	11,822	11,068	11,319	11,577	11,842	11,113	11,390	11,675	11,967	12,266		
Planned 2014		13,376	12,314	12,131	12,515	12,106	11,518	11,803	12,133	12,556	11,889	2014-24 AMP, Table 5.11, p.117
Difference		2,308	995	554	673	993	128	128	166	290		
Nominal $												

Table 2: Aurora AMP opex forecast

The difference between Aurora's 2012/13 actual opex and the 2013/14 forecast opex (approximately 2.5%[81]) can be explained entirely by the increase in opex to address the issues arising from our past breach of the service quality performance measures. Similarly, the majority of the difference of $7.6 million between the Commission's allowance for Aurora's opex for 2015-2020 and our own forecast[82] can be explained on the same grounds.

The forecast increase in expenditure (both opex and capex[83]) requires additional resources in Delta's asset management and energy divisions that plan, design, manage, operate, build and maintain the Aurora network. Workforce plans envisage an addition of over 20 new staff for which recruitment is progressively underway. Office positions include specialist asset planning, engineering, design and project management staff. Field positions include line mechanics, arborists, technicians and other industry qualified staff.

None of this is recognised in the proposed DPP reset. The Commission, despite having the above information at its disposal, has attributed the additional opex costs in 2013/14 to atypical costs/inefficiency/gaming. If the Commission's proposals are reflected in the final DPP decision, this could undermine Aurora's ability to heed the Commission's warnings about service quality breaches/increase the chances of breach.

The increase in opex from 2012/13 to 2013/14 reflects legitimate expenditure needed to ensure that service quality reflects consumer demands (consistent with the purpose in s52A(1)(b) of the Commerce Act). Use of 2012/13 data, either in part or solely, as the base year, would result in a systematic downward bias for the 2015-20 forecast of Aurora's opex. We consider it appropriate for the Commission, when making judgements about opex allowances etc., to take into account information from Asset Management Plans; particularly where this has been reviewed by its own experts. This is consistent with the operation of a low cost DPP regime.

An appropriate solution

Aurora believes that the Commission should use 2013/14 as the opex base year. Aurora has had a substantial step change in network opex, with a 23.7% increase from 2012/13 to 2013/14.[84] Use of 2012/13 as the base year would leave Aurora with a substantial hole in its revenue. We do not believe that failure to reflect necessary increases in opex in the DPP price reset would accord with "reasonable investor expectations". Use of 2013/14 as the base year would provide the strongest link between current and projected opex.

The rise in opex from 2012/13 (actual) and 2013/14 (forecast) of 6% compared to historic average should be put in the context of:

- Between 2008 and 2012, 79.3% of all annual changes in opex for non-exempt EDBs were upwards;
- The average increase in opex for non-exempt EDBs between 2008 and 2012 was 5.5%;
- Between 2011 and 2012 the average increase in opex for non-exempt EDBs was 8%;

[81] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, Figure 3.1.

[82] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, Table 2.2.

[83] Refer to the section: Aurora capex needs for 2015 – 2020.

[84] 2013/14 actual network opex is $11.174 million; 14% higher than the 2013 Information Disclosure forecast.

- Between 2011 and 2012, only one non-exempt EDB's opex declined (Wellington Electricity, by 1.56%). This contrasts with the comparison of opex from 2012/13 (actual) and 2013/14 (forecast) where four non-exempt EDB's opex are forecast to decline.

The Commission is incorrect to label the rise between 2012/13 and 2013/14 as "atypical". It is clearly consistent with the upward trend in opex that has been observable since 2008.

If the Commission does not adopt this option it should adopt, in order of preference, either:

- a combined opex base year that weights the most recent year more heavily than the older year; or
- an unweighted 2012/13 and 2013/14 combined opex base year.

Adoption of 2012/13 or an older year as the base year, when opex is unambiguously trending upwards, would result in a systematic downward bias in the opex forecast.

We are open to the option of the Commission selecting multiple years as the base year, <u>for future resets</u>, but only if: (i) the base year the Commission sets is known in advance so that the benefits of heightened/smoothed efficiency incentives can be realised; and (ii) there is no evidence or grounds to expect opex to increase/decrease in future years. The most suitable way to do this would be by amendment of the IMs to define the base year.

7 LIMITS ON HISTORICAL CAPEX

Aurora should not be subject to a 110% cap on historical average capex.

Aurora agrees with the Commission that "Within certain limits" it should rely on "each distributor's forecast to model their capital expenditure".[85]

We also support the imposition of a 120% cap on historical average capex.

In principle, while we understand the Commission's concern that some EDBs might "systematically bias their forecast to increase their starting price",[86] the Commission needs to ensure that it has a reasonable evidential basis for forming the view that an EDB has systematically biased their forecast before imposing a penalty, and that it does not curtail efficient, and reasonably forecast, capex.

Figure 3 shows that, if anything, exempt EDBs are more likely to overstate their capex requirements even though they have no gaming incentive to do so (it doesn't impact on the revenue they are able to recover), with Scanpower and Network Waitaki the most inaccurate. The split between non-exempt EDBs under-stating and over-stating their capex is broadly even, which would be contrary to expectations if there was a systematic bias in forecasts.

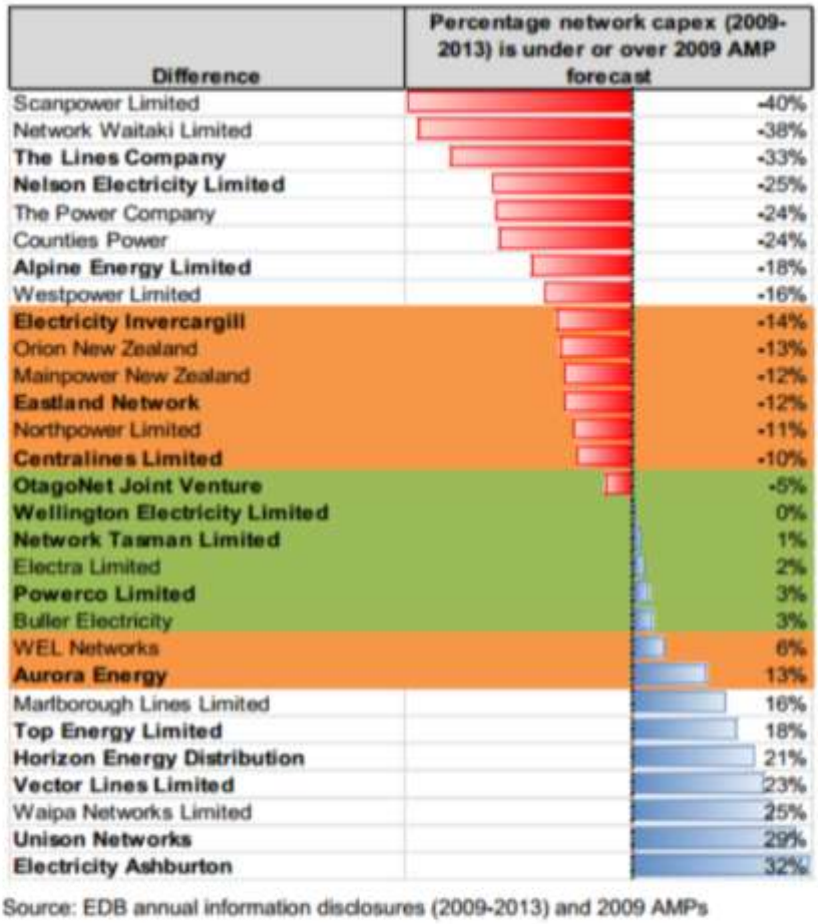

Figure 3: Percentage by which five year 2009 AMP forecasts were below or above actual expenditure[87]

[85] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 4.1.

[86] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 4.14.1.

[87] Powerco, Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues Paper, 30 April 2014, page 13.

Figure 4 also illustrates that capex can be volatile, resulting in forecasting errors, particularly if only one sample point (2010) is used to test the inaccuracy.

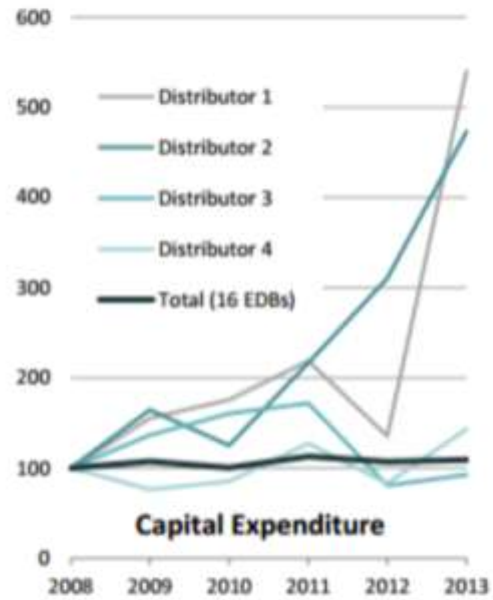

Figure 4: Change in capex 2008-2013[88]

This may suggest that there is an issue with forecasting errors, rather than with gaming/systematic bias.

Aurora does not consider that the appropriate test is solely whether a distributor's "2010 forecast was no more than 10% higher than out-turn" or "over 10% higher than out-turn".[89]

The Commission should also consider:

- Is the EDB able to provide reasonable reasons why its capex will need to be above 10%; and/or[90]
- Is the EDB able to reasonably explain why the forecast error occurred; and/or
- Could the forecast error be due to the lumpy nature of planned investment in the EDB's Asset Management Plans (a particular issue for smaller EDBs[91]) and/or
- Is the over-forecast part of an ongoing trend that the EDB systematically over-forecasts its capex, or is there a mix of over and under forecasting? The Commission should not just consider one data point (2010 forecast).

Aurora's capex needs for 2015 – 2020

Aurora reiterates our comments in relation to our service quality standard breach and the implications this has for opex and capex to remedy the situation.[92] Strata, on behalf of the Commission, reviewed the changes we made in our Asset Management Plan and made the following observations, reinforcing the need for increased capex:

[88] Commerce Commission, Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper, 21 March 2014, Figure 2.1.

[89] Commerce Commission, Low Cost Forecasting Approaches for Default Price-Quality Paths, 4 July 2014, paragraph 4.16.

[90] Refer to the section: Aurora's capex needs for 2015 – 2020.

[91] As pointed out by Unison in its "Submission on the Default Price-quality paths from 1 April 2015: Process and Issues Paper", 30 April 2014, paragraph 57.

[92] Refer to the section: Aurora specific evidence of opex increases.

> *"On our field inspections in Central Otago we found evidence that Aurora is undertaking a significant pole replacement programme. We found that the programme was being prioritised to address the worst performing feeders first and poles that had been inspected and "red tagged". It is likely that, if resourced adequately over time, this programme will address the network performance issues that have led to the performance breaches in recent years."* (emphasis added)[93]
>
> *"Based on our observations … it is likely that the proposed programmes and levels of expenditure will address the network performance issues that have led to the performance breaches in recent years."*[94]
>
> *"… Aurora's expenditure forecasts would seem to be far too low to deal with the backlog of assets in poor condition. Additionally, Aurora's 2013 AMP supports the view that some budgeted amounts are inadequate. For example; at page 5 Aurora estimates a cost in tens of millions to address Condition 0 vegetation management areas. At page 48 the AMP states there are 6,059 current vegetation management areas that represent an immediate danger to person or property."* (emphasis added)[95]

Aurora is at a capital lift stage, which requires significant additional investment. This has been well signalled publicly, including impact on dividends.[96]

Aurora is planning $139.2 million investment in its network over the next five years. This is significant additional investment that would see Aurora's capex increase from about $20 million a year to $32.9 million in 2014/15, and to $34.6 million in 2015/16, before declining again.

Aurora would have spent about $100 million on capital improvements if spending levels from recent years had continued, meaning increased investment amounts to about $40 million extra over five years.

The company's five-year spending plan would result in upgrades and replacement of key pieces of ageing infrastructure across the network.

This includes:

- Renewing or replacing ageing asset infrastructure in Dunedin, including substations, power poles, cables and centralised control room facilities inside the company's Halsey St headquarters. Some parts of the network are more than 60 years old and coming to the end of their useful economic life.

  To replace an aging pole fleet, Aurora has budgeted capital expenditure on pole replacement of $4 million for the current year ending 31 March 2015, across both its Dunedin and Central Otago sub-networks. This capex has been committed and agreed by the Board.[97]

- Enlarging the network's capacity in Central Otago where economic activity is picking up, and capacity needs to expand to match rising energy demands from developers and irrigators. One of the drivers is farm conversions to dairy, which has a greater need for irrigation.[98]

  System growth expenditure is also driven by residential subdivisions such as the Northlake Special Zone in Wanaka, approved last month, which could eventually add almost 1400 houses to the town, boosting its population by 50%[99]. (Part of the reason Aurora over forecast capex relative to actual was that we anticipated much of this investment would occur earlier than it has.)

---

[93] iBid, paragraph 55.

[94] iBid, paragraph 58.

[95] iBid, paragraphs 78 - 79.

[96] See for example: http://www.odt.co.nz/news/dunedin/307030/dcc-dividend-drop-dilemma and http://www.odt.co.nz/news/dunedin/311448/aurora-plans-1392m-upgrade.

[97] Aurora would be happy to provide Board Meeting documentation to the Commerce Commission of this commitment.

[98] Demand growth driven capex can be harder to forecast, than reliability investments, as it is out of the control of the EDB.

[99] See: http://www.odt.co.nz/news/queenstown-lakes/310503/council-votes-plan-change

For example, Aurora gained approval, in February this year, for a new substation at Hawea Flat to meet growing electricity demand in the Upper Clutha area.

In contrast to the Dunedin network, The Central Otago network is very much a growth network that is requiring investment. A number of existing developers, who put some of their developments on hold in recent years, are now restarting their developments

- In addition to the pole replacement:
  - $20 million has been approved in principle, for upgrade of SCADA, Control, Communications and Protection systems (SCCP). The SCCP programme consists of 8 interrelated projects that will modernise and integrate our network management, control and communications systems. The $20 million will be approved and committed in discreet components. $4.5 million has been committed and agreed by the Board so far;
  - $6 million is about to be committed to build a new Neville Street substation over the 2015 and 2016 periods;
  - $4.8 million has been agreed and committed to build a new Lindis Crossing substation over the 2015 and 2016 periods;
  - $4.5 million has been agreed and committed to build a new Camp Hill substation (Hawea Flat) in 2015; and
  - consent has been granted for a new $4 million Riverbank Road substation (Wanaka).[100]

Table 3, below, provides a summary of all capital expenditure on the Aurora network over the first five year period of the current Asset Management Plan 2014-2024, categorised by major expenditure driver for each region. Investment in centralised systems that relate to management of both networks is indicated as ‘Shared’.[101]

Expenditure driver	Dunedin $m	Central $m	Shared $m
System growth and consumer connection	$11.0	$53.9	$0.4
Asset replacement and renewal	$32.3	$19.0	$7.4
Asset relocations	$3.8	$2.4	-
Reliability, safety and environmental	$1.6	$2.6	$4.8
Total	**$48.7**	**$77.9**	**$12.6**

Table 3: Capital breakdown by expenditure driver (2014-2109)

Aurora expects that its debt will increase by $38.2 million, from $141.4 million to $179.55 million, by 30 June 2019 to accommodate the additional capex (partly debt funded/partly funded by a cut in dividends of $2 million a year to $7.5 million, from 2015/16). Total assets are projected to increase from $392.8 million to $460.2 million over the same period. The projected ratio of shareholder equity to total assets reduces slightly from 46.1% (FY 2014) to 44.6% (FY 2019).

[100] Aurora would be happy to provide Board Meeting documentation to the Commerce Commission of this commitment.

[101] The breakdown in terms of reliability and non-reliability investments is also worth noting in the context of the Commission’s WACC percentile consultation as the Oxera report, which the Commission relies heavily on, is based on an assessment of reliability only. Table 3 shows that, particularly for Central Otago, that non-reliability investments are a substantial portion of our projected capex.

An appropriate solution

The Commission should have confidence in Aurora's capex forecasting, notwithstanding any historic issues, and rely on it for DPP price resetting purposes, rather than impose a 10% limit, on the basis that:

- The Commission's expert, Strata, has considered Aurora's capex/AMP in the context of Aurora addressing service quality issues;
- There is clear evidence of the need for increased capex to meet reliability (particularly in Dunedin, given the age of assets) and observable demand growth (Central Otago);
- The bulk of the uplift is occurring in 2014/15 and 2015/16, so there is greater certainty over the accuracy of the forecast (the further out the capex forecast the less accurate it will be), and in terms of what is committed expenditure;
- The level of committed (Board approved) capex;[102] and
- The increase in capex has been reflected in reduced dividend payment commitments, agreed by both the Board[103] and our shareholder, DCHL, in the Statement of Intent for 2014/15.

Regardless of whether the Commission maintains the current 120% cap, or shifts to two-tier 110% and 120% limits, an option it should also consider is allowing EDBs to have any new capex treated as a recoverable cost (the depreciation and return on capital) for the regulatory period. This would avoid the risk, perceived by the Commission, that an EDB could profit from the Commission over-forecasting capex by underspending relative to the forecast, and "ensure distributors who have previously forecast higher than out-turn capital expenditure do not benefit in the event that this characteristic continues in the most recent capital expenditure forecasts".[104]

There would be no benefit for the EDB to opt for capex to be treated as a recoverable cost unless it genuinely considered that its capex requirements exceed the Commission's cap. It would also address the risk that the cap could hamper efficient investment (contrary to s52a(1)(a)) or result in unnecessary CPP applications (contrary to s53K).

[102] Aurora would be happy to provide Board Meeting documentation to the Commerce Commission of this commitment.

[103] Aurora would be happy to provide Board Meeting documentation to the Commerce Commission of this commitment.

[104] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph 4.23.

8 PARTIAL PRODUCTIVITY

Negative partial productivity should not be assumed to be temporary

Aurora is of the view that the Commission should either factor the negative partial productivity, determined by Economic Insights, into its opex forecast or remove the partial productivity component from the opex forecast formula altogether.

Economic Insights empirical evidence is that total factor productivity (TFP) has declined at a rate of -1% over the last decade (based on five out of six specifications of the TFP model they applied[105]) and that there had been "a significant change in market conditions facing the energy supply industry occurred around 2007 with significantly reduced growth rate in demand" in New Zealand and also "observed in Australia, Canada and the US":[106]

> *"There is some evidence from a range of comparable countries that a significant change in market conditions facing the energy supply industry has occurred recently. In New Zealand electricity throughput grew at an average annual rate of 2.4 per cent between 1996 and 2007 but since 2007 it has grown at less than 0.5 per cent. While the global financial crisis reduced demand for electricity in 2009, it recovered in 2010 but has remained virtually static since then. In Australia, electricity demand reversed in 2008 and has fallen at an average annual rate of 1.1 per cent since then. A similar pattern has been observed in Ontario (PEGR 2013b). Maximum demand also peaked in Australia in 2009 and has fallen in New Zealand in 2013."*
>
> *"Using the three–output specification used in Economic Insights (2009a), electricity distribution industry TFP grew at an average annual rate of 1.5 per cent up to 2004 but at only 0.1 per cent in the decade since. Using the four–output specification used in PEGR (2013a), TFP grew at an average annual rate of 1.2 per cent up to 2004 but at –0.6 per cent in the decade since. The corresponding average annual growth rates for the 18–year period are 0.8 per cent and 0.2 per cent, respectively. The TFP growth rates for the other three output specifications examined in this report lie between those for these two specifications.*
>
> *We are of the view that a significant change in market conditions facing the energy supply industry occurred around 2007 with a significantly reduced growth rate in demand which has now lasted for 6 years and which seems to be separate from the short term effects of the global financial crisis. This change has also been observed in Australia, Canada and the US. While the TFP specification used in our 2009 report points to marginally positive TFP growth over the past decade, the other five specifications examined point to negative TFP growth rates with the specification used in PEG (2009) pointing to a TFP growth rate of –1 per cent."*
>
> *"… 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. This is likely to contribute to a return to positive TFP growth in the electricity distribution industry in the medium term."*

Despite this evidence, the Commission has proposed "to assume that partial productivity for operating expenditure will not change over the upcoming regulatory period"[107] based solely on the stated view of Economic Insights that "there is … <u>some expectation</u> from experts … that positive electricity demand growth will resume" (emphasis added) and "This is likely to contribute to a return to a positive TFP growth … in the medium term".[108]

Against this, a number of submissions from EDBs suggest that the negative partial opex productivity is not temporary. It is disappointing that neither the Commission nor Economic Insights provides evidence as to why the EDBs are considered to be wrong. Neither the Commission nor Economic Insights make reference to the alternate EDB view.

105 Concerns were raised in previous consultation about the validity of the 2009 model that produced the positive productivity result.

106 Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2013, 24 June 2014, pages iii and iv.

107 Commerce Commission, Proposed Default Price-Quality Paths For Electricity Distributors From 1 April 2015, 4 July 2014, paragraph C18.

108 Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2013, 24 June 2014, pages iii and iv.

By way of example, we refer to the following submission excerpts on the matter:

> *"… the Commission puts forward its current view that "if there has been a deterioration in partial productivity, this change is likely to be temporary, e.g. due to temporary declines in demand." Vector notes that the Commission does not provide any evidence or analysis to support a view that any declines in demand are temporary. We refers the Commission to our analysis … in relation to revenue growth, which shows a consistent declining trend of usage per ICP on our network since at least 2005 as evidence that the declining trend does not appear to be temporary."*[109]
>
> *"For the 2012 DPP price path, an opex partial productivity factor of 0% was adopted. In the Paper it is suggests that there has been a temporary decline in opex partial productivity, due to a temporary decline in demand.*
>
> *We acknowledge the recent decline in both electricity peak demand and consumption. This trend started in 2008 around the same time as the GFC. While this may appear to be a temporary response to falling economic output, we note that electricity consumption is continuing to fall, even as New Zealand's real GDP rebounds. This suggests a structural change in electricity usage since 2008 which may go beyond a simple response to the economic downturn. We consider that one possible explanation is that electricity demand growth may remain persistently low.*
>
> *Anecdotally it has been suggested that this is partly due to investments in energy efficiency initiatives (eg home insulation schemes and more efficient appliances) and more energy efficient building practices for new homes. Continuing retail energy price increases have also incentivised users to find ways to conserve energy.*
>
> *Accordingly, we suggest that any structural changes in electricity usage need to be accounted for, and not unduly dismissed, in any modelling of partial productivity."*[110]
>
> *"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."*[111]
>
> *"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."*[112]
>
> *"In many respects, Unison is surprised that the Commission would consider a decline in demand a temporary phenomenon. Over the past decade power prices have increased substantially, driven initially by rising wholesale and retail price increases and more recently significant transmission and in a few cases distribution price increases. Average residential retail electricity prices since February 2000 have increased by 98% increase in the CPI over the same period, compared to a 41%.*
>
> *Although long-run demand elasticity's are low for electricity, they are not zero. The Electricity Authority's recent survey of electricity consumers also highlighted that only 20% of consumers reported "Do not make much effort" to manage their electricity usage. Accordingly, Unison submits that the appropriate working assumption for the Commission to make is that any decline in productivity resulting from a fall in demand is a permanent effect, and that it is more likely that consumers will continue to look for opportunities to reduce their power bills.*
>
> *Unison also observes that there are a number of supply-side factors that are also driving potential productivity declines (including relative to the rest of the economy). A significant proportion of expenditure is on maintaining and repairing infrastructure. This substantially involves transport and*

---

[109] Vector, Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper 30 April 2014, paragraph 109.

[110] PricewaterhouseCoopers, Submission to the Commerce Commission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper, 30 April 2014, paragraphs 52 – 55.

[111] Powerco, Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper, 30 April 2014, page 7.

[112] Powerco, Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper, 30 April 2014, paragraph 53.

people related costs. We are not aware of significant transport-related efficiencies (indeed in Hawke's Bay the "Safer Roads" initiative has reduced speed limits on a number of key arterial routes by 20%, increasing travel times). Changes to Health and Safety legislation are also likely to impact negatively on productivity as additional precautions are introduced to further reduce the risk of adverse outcomes. Being a high-hazard industry changes to health and safety legislation may have a relatively greater impact on EDBs compared to the average of the economy. "[113]

On Aurora's network, residential electricity kWh change has averaged -2.6% from 2010-2015, with the most substantive reduction of nearly -8% in 2014. This is reflected in figure 5.

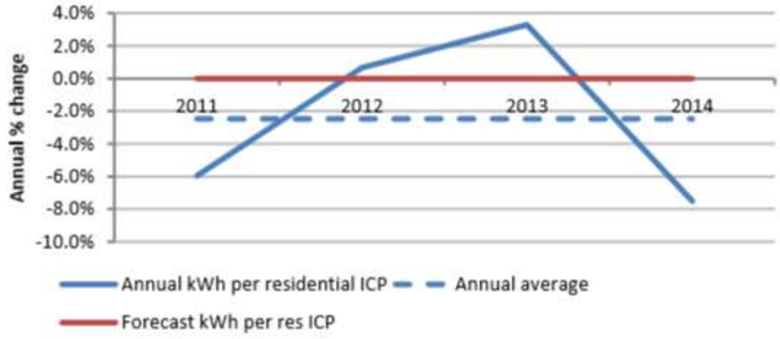

Figure 5: Aurora residential electricity usage v Commission assumptions

Consistent with the High Court Part 4 IM Merit Appeal, the Commission should "not be prepared to assume"[114] that the negative productivity is only temporary, in the face of evidence to the contrary. As the High Court stated "Where a proposition is simply asserted by economic experts, we give it little or no weight".[115]

[113] Unison, Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper, 30 April 2014, paragraphs 33 – 35.

[114] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013, paragraph [588].

[115] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC 3289 [11 December 2013], paragraph [1745].

9 CONSTANT PRICE REVENUE GROWTH FORECASTING

Total constant price revenue growth forecasting needs further attention

Aurora considers that the Commission's constant price revenue growth forecasting should be reviewed, based on experience with the Commission's forecasts against actual. The Commission has done the same in relation to EDB forecasts of capex versus actual.

For the 2012 reset the Commission assumed Aurora's constant price revenue growth would be 0.6%; in comparison with -2.6% for 2011 and 0.3% for 2012. The average for 2010-14 was 0.3%, half that forecast by the Commission. This is reflected in Table 4 and Figure 6 below. Table 4 also includes a breakdown of the components of the forecast against actual.

	2010	2011	2012	2013	2014	2010-14 average
Total constant price revenue growth - Actual vs 2012 DPP forecast						
Constant price distribution rev	52,609	51,267	51,442	52,860	53,313	
% change		-2.6%	0.3%	2.8%	0.9%	0.3%
annual average % change		0.3%	0.3%	0.3%	0.3%	
2012 DPP forecast						
% change		0.6%	0.6%	0.6%	0.6%	0.6%
Comparison of % changes						
Constant price distribution rev						0.3%
2012 DPP forecast						0.6%
Difference						-0.3%

Table 4: Aurora's total constant price revenue growth: actual v forecast

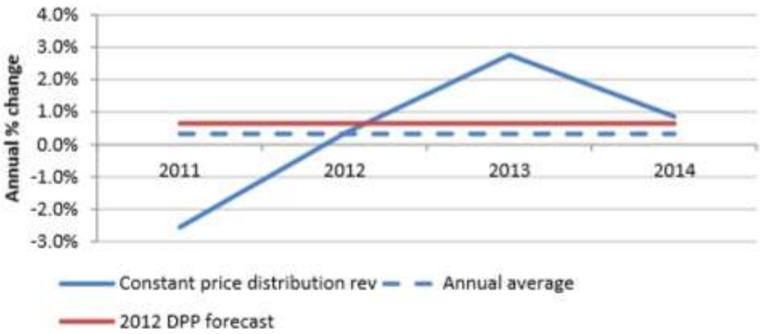

Figure 6: Aurora's total constant price revenue growth: actual v forecast

We would also note that errors in assumptions on GDP/revenue, population/ICP and ICP/kWh are compounding. A minor error in one can be magnified by another.

GDP Forecasts

Aurora has significant concerns over the accuracy of NZIER's forecasts of regional GDP, which the Commission proposes to use as a determinant of constant price revenue growth associated with commercial and industrial connections[116]. The Commission's redacted modelling reveals a forecast annual change in real GDP for Otago-based EDB's, including Aurora, which is second only to Auckland (by 0.03% per annum). We observe that the Commission has noted "Our exploratory analysis of the relationship between GDP growth and revenue growth for distributors shows that OtagoNet is anomalous. We therefore consider it appropriate to exclude OtagoNet from our model as its inclusion distorts the results significantly"[117] and "We also excluded Aurora Energy at the previous reset for the same reason, however, with updated data, we no longer consider their

[116] Aurora's pricing does not segment in this manner; however. Aurora has only standard domestic pricing, based predominantly on energy throughput, and "other" pricing based on a combination of capacity, demand and distance factors. Refer to Aurora's Use-of-System Pricing Methodology available from http://www.auroraenergy.co.nz/content/pricing.php

[117] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, paragraph C17.

observations to be anomalous"[118]. We understand, from discussion with the Commission[119], that the NZIER process has not changed, and that the same data integrity issue that existed at the last reset persists. Accordingly, Aurora is concerned that there may be valid reasons for continuing to exclude Aurora from the model.

Aurora recommends that the Commission base constant price revenue growth on historic trend, rather than relying on NZIER regional GDP growth forecasts etc.

Real Infrastructure Competition

In the Frankton Flats area of Queenstown, Aurora finds itself in a position that we understand to be unique nationally, in that we face genuine infrastructure competition from an unregulated, grid-connected EDB[120] (as opposed to embedded networks, commonly connected to EDBs). The nature of the competition is mainly for new electricity connections, although there has been some attempted conversion activity.

Whilst Electricity Southland's existing consumer base is understood to be relatively small compared to Aurora's, competition is taking place within an area of land that is currently undeveloped and which is the subject of proposed district plan changes designed to facilitate; educational, residential, visitor accommodation, commercial, industrial, business, and recreational activities.[121] Aurora expects that a significant proportion of Queenstown development will take place on the Frankton Flats, and will be subject to infrastructure competition. As an example, Aurora has been advised that it was unsuccessful in its proposal to supply the 750-lot Shotover Country subdivision.[122]

In view of the very real competition for new connections, and the multi-use nature of Frankton Flats, Aurora considers that the Commission's revenue modelling is likely to overstate the forecast position for Aurora, in terms of both domestic and non-domestic revenue. In Aurora's view, some form of deflator needs to be applied to the Commission's forecast of Aurora's constant price revenue growth.

[118] Commerce Commission, Low Cost Forecasting Approaches For Default Price-Quality Paths, 4 July 2014, footnote 85, p66.

[119] Commerce Commission, email from Robert Gordon, 23 July 2014.

[120] Electricity Southland Limited is owned in equal shares by non-exempt EDB Electricity Invercargill Limited and exempt EDB The Power Company Limited, via their respective holding companies Pylon Limited and Last Tango Limited.

[121] Queenstown Lakes District Council, Section J Plan Change 19 Frankton Flats B Zone.

[122] See http://www.odt.co.nz/news/queenstown-lakes/258708/wakatipu-finds-room-grow

10 REVENUE-LINKED SERVICE QUALITY SCHEME

As noted above, Aurora supports the adoption of a revenue-linked service quality scheme. Aurora has previously supported revenue-quality linkages, and is pleased to see the Commission's proposes to introduce this incentive scheme.

As part of the specification of the scheme for the 2015 EDB DPP reset the Commission should consider the extent to which it would be desirable to incentivise EDBs to improve service quality over-time, and the linkages between opex/capex and service quality, and how these linkages are reflected in this and future resets.

We also consider that there will be considerable scope to improve and enhance the revenue-linked service quality scheme over time (particularly by linking revenue to consumers' willingness to pay), but that it makes sense to take a tentative approach for the initial introduction of the scheme.[123]

We broadly agree that the incentive scheme represents an improvement over the current 'pass/fail' approach. We support the following features of the Commission's proposal:

- A relatively weak starting incentive: In our view, the proposed approach allows EDBs to become familiar with the principles of incentive based regulation, without excessive risk. We note incentives are likely to strengthen over time, and we are relatively comfortable with that, provided the underlying reliability measures remain objectively and rationally derived. We do question, however, whether an asymmetric incentive may be more appropriate in the long run. In our view, the incentive to maintain quality through a revenue penalty for poor performance is likely to be much stronger, naturally, than the incentive to improve reliability performance through a revenue reward, given the scale of off-setting investment required to effect a veridical reliability improvement.

- Normalisation of unplanned interruptions only: This Commission's rationale for normalising unplanned interruptions only is, in our view, sound. In our experience, restoration activities during maximum event days are generally so resource intensive that planned outages are deferred as a matter of necessity anyway.

- Introduction of an EDB specific k-value to adjust for the effect of zero event days: We consider that the proposed methodology results in a material improvement to boundary level calculations for those EDBs with a significant number of zero-event days.

- A 50% weighting on planned events. We agree with the Commission's view that planned interruptions are less disruptive to consumers than unplanned interruptions.

As it stands; however, Aurora considers that there are number of issues in the Commission's proposal that would benefit from reconsideration and/or refinement. Such issues include:

- Transition to a SAIFI trigger for maximum event day normalisation;

- Removal of breach amounts in target calculations;

- A target-based compliance standard; and

- Vague enforcement criteria.

Some of these features fundamentally alter the general stability of the quality path, beyond recalculation of boundaries and targets, to the extent that Aurora has difficulty in supporting them.

[123] Refer to the section: Priority work areas from 2015 onwards for the 2020 resets and beyond.

Transition to a SAIFI trigger for maximum event day normalisation

Under the Commission's proposal for resetting the quality path, the current arrangement of using a SAIDI maximum event day as a normalisation trigger will be discontinued, and normalisation will occur only on SAIFI maximum event days. That is, SAIDI may only be normalised if both the SAIFI and SAIDI boundary values are exceeded.

The Commissioned has stated that this change is necessary to ameliorate a potential weakness in the current approach that EDBs might exploit to the detriment of consumers. The Commission considers that, under the current approach, when a SAIDI maximum event day occurs, the ability to normalise removes all incentives for the EDB to restore service as quickly as possible, because SAIDI is limited to the boundary value. Aurora takes exception to any suggestion we would disregard service quality on these grounds. The Commission's WACC percentile consultation material also makes it clear the Commission considers there are wider disciplines on service quality than the DPP/service quality standards. In Aurora's judgement, the Commission should not base its decisions on hypothetical propositions. The Commission's argument completely lacks any empirical evidence to back the assertion that this is happening in practice or might be actively considered by EDBs.

EDBs face natural incentives to restore service promptly

EDBs are faced with a range of incentives to restore service promptly, that more than adequately compensate for any lack of incentive to "minimise the duration of an event once the boundary has exceeded".[124] In this regard, we consider the Commission is wrong to state that there are "potential perverse incentives using SAIDI as the normalisation trigger".[125] The absence of an incentive to do something does not automatically give rise to the corollary that an incentive exists (perverse or otherwise) not to do that thing.

Aurora considers the following factors give impetus to prompt restoration of service:

- A significant component of Aurora's revenue is determined by the quantum of energy delivered to consumers. Accordingly, outages have a direct revenue impact that provides a significant incentive to restore service without delay. The larger the event, the stronger that this incentive becomes.
- Aurora's use-of-system agreements with electricity retailers provide for the payment of compensation for service failure where outages exceed defined durations.
- Changes to the Consumer Guarantees Act, and pre-emptied by/duplicated in the Electricity Authority's 2012 amendment to the Electricity Industry Participation Code (Part 12A), has increased the likelihood of additional consumer compensation claims. Although this is an emerging issue, with little certainty as to how this will play out in practice, the uncertain nature and potential significant cost impact provides a fairly strong driver for service continuity.
- Outages frequently result in customer complaints all of which take time and associated cost to resolve. In this regard, EDBs have the same incentives to maintain service levels as faced by any business.
- Aurora is concerned about ensuring consumer wellbeing/satisfactory service and about the reputational risks of poor service quality performance.

[124] Commerce Commission, Proposed Quality Targets and Incentives for Default Price-Quality Paths from 1 April 2015, 18 July 2014, paragraph 3.21.

[125] Commerce Commission, Proposed Quality Targets and Incentives for Default Price-Quality Paths from 1 April 2015, 18 July 2014, paragraph 3.22.

SAIFI trigger fundamentally reconfigures the quality path

The consequence of moving to a SAIFI trigger is, in Aurora's case, a fundamentally harder quality standard to achieve than under the current regime, and which is not reflected in any price trade-off.

The Commission has justified the move to a SAIFI trigger, in part, because "…extreme events are most likely to affect a large number of customers …";[126] however, this is not necessarily correct. Major event days are, in our view, just as likely to occur as a consequence of significant damage to relatively confined areas. The extent to which SAIDI or SAIFI dominates is likely to be different for each EDB, influenced by network topology and regional geography. For the Aurora network, SAIDI tends to dominate.

Figure 7, below, using the Commission's modelling data, describes the underlying relationship between SAIDI and SAIFI for the Aurora network. Whilst a direct observation of SAIDI and SAIFI is not particularly useful, graphing on a log-log scale causes the plot to trend towards the linear. Using the indicated trend line, it then becomes a matter of fairly simple mathematics to determine that, for the proposed SAIFI boundary of 0.262 system interruptions to adequately trigger a maximum event day, the corresponding SAIDI boundary would need to be 34% lower than proposed, at 7.26 system minutes (compared to the 10.92 system minute boundary proposed).

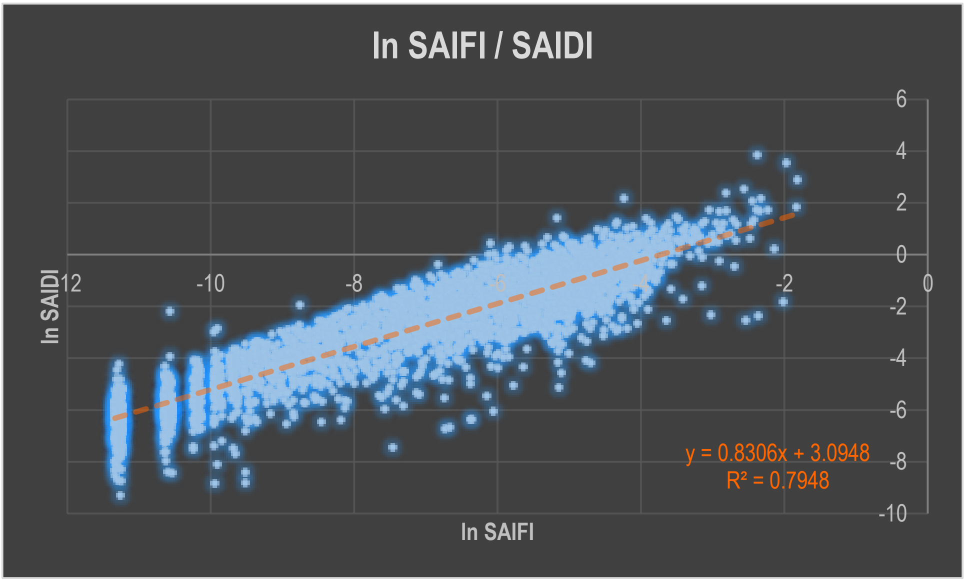

Figure 7: SAIFI/SAIDI relationship for the Aurora network

That the proposed reliability boundaries do not correspond to each other, consistent with the underlying relationship described above, is not surprising since they have been determined independently. On this basis, Aurora does not oppose the view of the ENA that boundaries should be independently triggered;[127] however, we note that the IEEE considers SAIDI to be the appropriate normalisation trigger.[128] Given the wide acceptance of the IEEE as an international industry standards setting body, Aurora supports the IEEE view in preference.

The ultimate effect, for Aurora, of moving to a SAIFI trigger is illustrated below, again using data from the Commission's modelling data.

Table 5 shows that under a SAIDI trigger, Aurora would have been able to normalise SAIDI for 4 maximum event days during the 10-year reference period. In that time, Aurora would have

126 Commerce Commission, Proposed Quality Targets and Incentives for Default Price-Quality Paths from 1 April 2015, 18 July 2014, paragraph 3.20.

127 Electricity Networks Association, Pathway to Quality: Quality of Service Incentives Working Group Report, February 2014, page 47.

128 Refer to the discussion below: SAIDI normalisation.

exceeded the SAIDI target three times, but would not have exceeded the incentive cap. In respect of SAIFI, Aurora would have been unable to normalise SAIFI at any time, and would have exceed the SAIFI target 6 times, and exceeded the incentive cap twice.

	Disclosure Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
SAIDI	Planned	3.65	5.86	6.59	6.64	4.41	5.59	8.46	6.73	10.9	11.66
	Unplanned	73.21	70.8	83.52	79.63	59.15	61.3	93.02	100.49	53.8	71.18
	Total	76.86	76.66	90.11	86.27	63.56	66.89	101.48	107.22	64.7	82.84
	Normalisations				1			1	2		
	Target Exceed?			Yes				Yes	Yes		
	Cap Exceed?										
SAIFI	Planned	0.036	0.043	0.052	0.051	0.027	0.043	0.059	0.045	0.058	0.053
	Unplanned	1.386	1.401	1.588	1.372	1.172	1.252	1.361	1.704	0.929	1.104
	Total	1.422	1.444	1.640	1.423	1.199	1.295	1.420	1.749	0.987	1.157
	Normalisations										
	Target Exceed?	Yes	Yes	Yes	Yes			Yes	Yes		
	Cap Exceed?			Yes					Yes		

Table 5: Historic reliability performance under the Commission's proposal - SAIDI trigger

Table 6 shows the effect of the proposed SAIFI trigger. As expected, the SAIFI picture remains unchanged; however the fact that no SAIDI normalisation can occur means that the SAIDI target is now exceeded four times (3 times under SAIDI trigger) and the incentive cap is now exceeded twice (0 times under SAIDI trigger).

	Disclosure Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
SAIDI	Planned	3.65	5.86	6.59	6.64	4.41	5.59	8.46	6.73	10.9	11.66
	Unplanned	73.21	70.8	83.52	115.99	59.15	61.3	94.62	131.39	53.8	71.18
	Total	76.86	76.66	90.11	122.63	63.56	66.89	103.08	138.12	64.70	82.84
	Normalisations										
	Target Exceed?			Yes	Yes			Yes	Yes		
	Cap Exceed?				Yes				Yes		
SAIFI	Planned	0.036	0.043	0.052	0.051	0.027	0.043	0.059	0.045	0.058	0.053
	Unplanned	1.386	1.401	1.588	1.372	1.172	1.252	1.361	1.704	0.929	1.104
	Total	1.422	1.444	1.640	1.423	1.199	1.295	1.420	1.749	0.987	1.157
	Normalisations										
	Target Exceed?	Yes	Yes	Yes	Yes			Yes	Yes		
	Cap Exceed?			Yes					Yes		

Table 6: Historic reliability performance under the Commission's proposal - SAIFI trigger

Aurora is gravely concerned the proposed move to a SAIFI trigger would mean that future normalisation is unlikely to occur due to the specific underlying relationship between the two indices for the Aurora network and, as a consequence, target and incentive cap breaches are more likely, with the very real consequence that Aurora's reliability performance may be perceived by the Commission as deteriorating when, in fact, underlying long-term performance may be unchanged or improved.

We consider our concerns to be reasonable, given Aurora's proposed target is calculated as the arithmetic average of historic data, without normalisation. The law of averages would dictate that Aurora should expect to exceed its targets 50% of the time.

SAIDI Normalisation

As noted above, the IEEE considers that SAIDI is the appropriate trigger for maximum event day normalisation:[129]

> *"An ideal measure of unreliability would be customer cost of unreliability—the dollar cost of power outages to a utility's customers. This cost is a combination of the initial cost of an outage and accumulated costs during the outage. Unfortunately, the customer cost of unreliability has so far proven impossible to estimate accurately. In contrast, the reliability indices above are routinely and accurately computed from historical reliability data. <u>The ability of an index to reflect customer cost of unreliability indicates the best one to use for MED identification.</u>*
>
> *Duration-related costs of outages are higher than initial costs, especially for major events, which typically have long duration outages. <u>Thus, a duration-related index will be a better indicator of total costs than a frequency-related index like SAIFI or MAIFI.</u>"* (emphasis added)

Aurora considers that, given the significant extent to which the IEEE 1366 standard informs and underpins the Commission's approach to quality of service regulation, the Commission's contemplation of such a significant deviation from the standard risks a material compromise to the integrity of EDB price-quality regulation.

With this in mind, the Commission should maintain the use of a SAIDI trigger for normalisation of maximum event days, as recommended by the IEEE 1366 standard. As an alternative, owing to the independent derivation of SAIDI and SAIFI boundaries, Aurora would also support the view offered by the ENA, that SAIDI and SAIFI should be separately triggered.

Aurora does not support the proposal to use of SAIFI as the maximum event day trigger.

Removal of breach amounts in target calculations

The Commission has proposed that EDBs that breached the quality standards during the current regulatory control period should have the amount of the breach deducted from the target calculation. That is, in the breach year, the offending EDB's normalised annual value will be set to its existing limit (before adjustment for the 50% weighting on planned outages).

The Commission has reasoned that this adjustment is necessary to ensure "distributors should not receive a higher (less challenging) target due to past quality breaches".[130] Whilst we understand the Commission's view on this matter, we consider that this approach is inconsistently applied, without merit generally, and unwarranted in the specific case of Aurora.

In Aurora's view, such an approach merely carries the consequences of a poorly designed quality compliance regime from the current regulatory control period, into the next. While not wishing to dismiss the disruptive effect that reduced reliability has on consumers, the fact is the current compliance standard contains an inherent element of chance. An EDB will breach the current standard if it is unlucky enough to exceed a quality target in two consecutive years; however, should the EDB record the same results in non-consecutive years, no breach occurs. Exceeding the target on consecutive years is not a valid indicator that an EDB's underlying reliability trend is deteriorating, as we demonstrate below. The question must be asked, all other things being equal, are consumers materially more disadvantaged when an EDB exceeds quality targets in consecutive years, over exceeding the targets in non-consecutive years? In Aurora's view, they are not, and a longer-term view of quality should be taken.

The issue that should be considered, before applying punitive adjustments to the 2016-2020 quality target calculation, is whether underlying quality performance has materially degraded. Table 7, below, shows Aurora's reliability performance over the proposed reference period,

[129] IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices, 31 May 2012.

[130] Commerce Commission, Proposed Quality Targets and Incentives for Default Price-Quality Paths from 1 April 2015, 18 July 2014, paragraph 4.16.

calculated using the Commission's dataset[131], and normalised using the proposed boundary values and SAIFI trigger[132]. The only adjustment we have made is to place a 100% weighting on planned interruptions, so that the result may be directly compared to the current reliability targets. The results indicate that the average SAIDI and SAIFI performance has been below the current target (SAIDI - 2.74% below target, SAIFI – 14.92% below target), and demonstrates that an improvement in reliability performance has been achieved. On this basis alone, Aurora considers the breach adjustment to be unwarranted.

	Disclosure Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Average	Limit	% Var.
SAIDI	Planned	7.30	11.72	13.17	13.29	8.82	11.17	16.92	13.46	21.81	23.32			
	Unplanned	73.21	70.80	83.52	115.99	59.15	61.30	94.62	131.39	53.80	71.18			
	Total	80.51	82.52	96.69	129.28	67.97	72.47	111.54	144.85	75.61	94.5	95.59	98.29	-2.74%
SAIFI	Planned	0.073	0.086	0.104	0.103	0.055	0.086	0.117	0.091	0.117	0.107			
	Unplanned	1.386	1.401	1.588	1.372	1.172	1.252	1.361	1.704	0.929	1.104			
	Total	1.459	1.487	1.692	1.475	1.227	1.338	1.478	1.795	1.046	1.211	1.421	1.670	-14.92%

Table 7: Historic reliability performance, normalised under Commission's proposal, 100% weighting on planned outages – SAIFI trigger

As a matter of principle, Aurora considers the proposed breach deduction to be additional enforcement action for its 2012 quality breach, in such a manner as to offend the principles of natural justice. Following an investigation into the underlying causes of Aurora's 2012 breach, the Commission decided, in respect of enforcement action, to issue Aurora with a warning letter.[133] The warning letter identified that "In terms of conduct, having assessed the circumstances of the non-compliance, we considered that there was no serious fault on Aurora's part" and "…we did not identify any significant specific detriment to consumers on Aurora's network as a result of the non-compliance…". In the content of the warning letter, no mention was made that the breach would also result in consequences that would be carried into the next regulatory control period. Aurora considers that for this approach to be procedurally fair, the Commission should have noted the consequence in its warning letter, and provided Aurora with the opportunity to respond.

Aurora also notes that the manner in which the proposed breach penalty is applied is inconsistent, in that it selectively applies to non-compliances within the current regulatory control period only. If the approach was to be consistently applied, adjustments for EDBs breaches of thresholds under the former targeted control regime would also have been made. At this juncture, and for the reasons stated above, we stress that we are not advocating the Commission take such an approach.

Finally, we note the quality target reset mechanism tends to apply a "sinking lid" that ratchets up service quality requirements over time. Like all sinking lid mechanisms, this could ultimately result in targets that are unsustainable (unless offset by an exponential increase in reliability investment). Aurora considers that the Commission's proposed breach adjustment simply accelerates the path toward the potentially unsustainability tipping point.

A target-based compliance standard

Our preference would be to have non-compliance judged on the basis of the incentive cap being exceeded, with a breach of regulation being determined on the current two out of three year assessment rule. While we do not like the element of chance that such an approach would re-introduce, it may have the effect of suppressing false positives, in terms of identifying material deterioration of reliability performance.

[131] Commerce Commission, Model 17a – Quality of service targets supporting data and intermediate calculations (excel version) draft EDB reset, 18 July 2014.

[132] Due to the consequences of the SAIFI trigger no normalisation is permitted and the stated annual values are effectively the "raw" values for that year. Refer to: Transition to a SAIFI trigger for maximum event day normalisation

[133] Commerce Commission, Warning letter to Aurora energy Limited in response to 2012 quality standards non-compliance, 26 June 2014.

Greater clarity around compliance enforcement would be desirable

Aurora notes the Commission's statements that:

> *"Failure to meet the SAIDI target or SAIFI target would constitute non-compliance with the quality standards. The Commission may take enforcement action and seek pecuniary penalties under section 87 of the Commerce Act, or criminal sanctions under section 87B of the Commerce Act, for failure to meet the quality standards."*
>
> *"In the case of unintentional breaches, we do not propose to take enforcement action for performance worse than the quality targets but still the below the cap except in exceptional circumstances…"*[134]

We consider these statements to be unnecessarily vague, and somewhat contradictory. As an illustration, we question why the Commission would consider that any EDB would intentionally breach the quality standards? Further, the Commission could be clearer on such matters as what would constitute exceptional circumstances.

We recommend the Commission take steps to develop enforcement guidelines for the DPP that better reveals the Commission's intentions with regard to compliance. This is particularly important given the "average-based" reliability targets which, if the Commission's proposal remains unchanged, is likely to increase the incidence of non-compliance, in our view.

While the Commission has generic Enforcement Criteria to assist it in its discretionary activities when making decisions on whether to open an investigation, and what enforcement action it will take at the end of an investigation, and Enforcement Response Guidelines, it also has specific compliance guidelines on matters including Fair Trading Act, credit fees under the Credit Contracts and Consumer Finance Act etc.

Aurora agrees with Alpine Energy's views on the need for guidelines on compliance enforcement:[135]

> *"While the process and issues paper does not invite views on the release of enforcement guidelines we would like to take this opportunity to once again raise our concerns about the lack of guidelines with the Commission.*
>
> *Uncertainty around the process that the Commission will take when it exercises its enforcement discretion presents a serious concern for us. Part 4 of the Commerce Act gives the commission significant discretion to take enforcement action for breaches. Regulated suppliers currently only have limited precedent upon which to base how the Commission is likely to exercise its discretion when taking enforcement action.*
>
> *To date the Commission has released two enforcement responses for breaches of the DPP at the 2011 and 2012 assessment dates. The Wellington Electricity Lines Limited settlement agreement provides some indication of the process that the Commission will take. However the Orion New Zealand limited warning letter provides none.*
>
> *In the process and issues paper the Commission expressed the view that '[e]nforcement guidelines and informative precedents will contribute to reducing this uncertainty…, which is encouraging as it indicates that the Commission may be considering the release of enforcement guidelines.*
>
> *We are of the view that enforcement guidelines will go a long way in providing regulated suppliers, including EDBs, with an appropriate level of certainty. And agree that while enforcement guidelines will reduce uncertainty the guidelines will never eliminate uncertainty entirely. Accordingly, we encourage the release of enforcement guidelines for the start of the next regulatory period"*

[134] Commerce Commission, Proposed Quality Targets and Incentives for Default Price-Quality Paths from 1 April 2015, 18 July 2014, paragraphs 2.19 and 2.20.

[135] Alpine Energy, Submission to the Commerce Commission on Default Price-Quality Paths from 1 April 2015 for 17 electricity distributors: Process and issues paper, 30 April 2014, paragraphs 4.1 – 4.5.

Interrelationship between service quality performance setting and DPP resets

Vector has expressed the view that "the reliability target for the next regulatory period should not be changed from the reliability target in the current regulatory period without corresponding adjustments in prices. For example, if the Commission were to set a reliability target that is lower than exists in the current regulatory period, that would require the EDB to invest to deliver a higher quality of service to its customers after 1 April 2015 than they had previously been required to. It is not reasonable to require the EDB to deliver this higher quality of service without compensating them for it through increased revenues (this is at the core of the price-quality trade-off)."[136]

This statement is worth considering in the context of the Commission's views on the opex base year, and the revenue-linked service quality scheme. The revenue-linked service quality scheme, if working well, will result in EDBs increasing opex (and capex) in order to improve service quality (where the increased costs are less than the benefit to consumers of improved service quality). This should be reflected in higher base year opex (and RAB) and, in turn, in higher allowed revenue for the next regulatory period.

The Commission's "Low Cost Forecasting Approaches for Default Price-Quality Paths" paper signals that there will be a risk that the Commission will treat the higher opex as "atypical" and instead rely on an earlier/lower opex base year.

EDBs would need to consider whether the 1% reward is sufficient if the improved service quality results in a higher service quality performance standard in the next regulatory period, but requires higher opex to be sustained that might not be reflected in the next regulatory period's allowable revenues. The Commission's decisions on opex base year and capex allowances will be critical to EDBs' perception of this risk (and "reasonable investor expectations"). Adoption of a 2012/13 base year (in part or in whole) could undermine the revenue-linked service quality scheme and limit incentives to improve service quality to options that don't require increased capex or opex.

[136] Vector, Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper, 30 April 2014, paragraphs 125.

11 WASH-UP PASS-THROUGH AND RECOVERABLE COSTS

A wash-up mechanism is the best option for dealing with uncertainty about pass-through and recoverable costs

Aurora agrees with the Commission's view that "In principle, distributors should be able to recover pass-through and the allowed recoverable costs in full".[137] This is consistent with "reasonable investor expectations". As Telecom has noted: "reasonable investor expectations are that they will receive a normal return over the life of assets …"[138]

We welcome the comments from gentailers in cross-submissions; all of whom supported this principle.

We also agree with the Commission that full recovery of pass-through and recoverable costs is "problematic" because "First, distributors have difficulty forecasting the amounts required to cover pass through and recoverable costs" and "Secondly, the recovery of the amounts required to cover pass through and recoverable costs are associated with some degree of volume risk".[139]

Aurora specifically incorporates "head-room" of $200,000 into recovery of pass-through and recoverable costs to avoid the risk of breaching our price path.[140]

Aurora submits that there are no legitimate benefits to consumers from regulated suppliers being exposed to the risk of under-recovery of pass-through and recoverable costs. If a regulated supplier is not able to fully recover these costs, it may mean artificially lower prices to consumers, but so would any policy that involves setting the DPP deliberately below cost. This is a short-term and opportunistic benefit only for consumers. Any aspect of the DPP that systematically undermines the ability of regulated suppliers to fully recover their costs, including a normal rate of return, comes at a cost to consumers of potentially interfering with the ability of regulated suppliers to efficiently invest and maintain their networks (which is particularly problematic where there is an identified need to increase opex in order to improve service quality, as is the case with Aurora). This is a particular issue, given that the Commission has not made additional allowances for uncertainty, beyond allowing a 75th percentile WACC that it now proposes to reduce to the 67th percentile.

We welcome Contact Energy and Mighty River Power's support for the need to make amendments to the treatment of pass-through and recoverable costs, to enable full cost recovery.[141]

---

[137] Commerce Commission, Proposed Default Price-Quality Paths For Electricity Distributors From 1 April 2015, 4 July 2014, paragraph 5.2.

[138] Telecom, UCLL and UBA FPP: consultation on regulatory framework and modelling approach, 6 August 2014, paragraph 85.

[139] Commerce Commission, Proposed Default Price-Quality Paths For Electricity Distributors From 1 April 2015, 4 July 2014, paragraph 5.3.1.

[140] Aurora Energy, Submission to the Commerce Commission on its Draft Decisions Paper (July 2011) on 2010-15 Default Price Quality Path for Electricity Distribution, 24 August 2011, section 3.2.2.

[141] The Commission has invited views on Genesis Energy's argument that full pass through of costs removes any incentives for distributors to ensure that any cost increases are justified.[141] Genesis Energy has suggested "requiring EDB's to demonstrate cost advocacy as part of their annual compliance statement reporting." [Commerce Commission, Proposed Default Price-Quality Paths For Electricity Distributors From 1 April 2015, 4 July 2014, footnote 40.]

We have the following observations about this.

Genesis Energy provide no evidence that such a requirement or precluding full cost recovery would provide benefits from lower pass-through and recoverable costs. The DPP regime has been in operation for five years with less than full cost recovery. If there was any evidence to support Genesis Energy's position it should be observable from this period.

We would also note that we have not seen any evidence of Genesis Energy or any other retailer applying the same standard to their own pass through of increases in distribution and transmission charges, or other pass-through type charges. We don't anticipate that future Genesis Energy price increases will be accompanied with a report demonstrating cost advocacy. Indeed gentailers have been notable in that they engage much less in Commerce Commission price control/economic regulation processes than their counterparts in airlines and the telecommunications sector. For example, Genesis Energy did not submit on the Commission's process and issues paper, and only provided a brief cross-submission. There is no evidence from Genesis Energy's submission of demonstrating cost advocacy.

Commerce Commission hybrid, ENA and Vector options

We welcome the efforts from the ENA and Vector to propose potential solutions that the Commission could adopt. We consider that these efforts are very constructive.

Aurora supports the ENA proposal. We consider the Vector proposal to be a second-best option.

We believe a wash-up mechanism should be introduced, under which any under or over-recovery of notional revenue, adjusted for the time-value of money, would occur following an assessment period. We caution that the Commission should avoid overcomplicating the wash-up mechanism.

We also support the ENA proposal that the wash-up not be constrained to specific causes, such that under or over-recovery would not result in a breach of the price path, but would instead require an adjustment at a later time. We agree there are other forecast risks than just for pass-through and recoverable costs, such as the impact of tariff rebalancing, which should be addressed.[142]

We do not believe there is any detriment to consumers from the ENA proposal, as long as the time-value of money is set appropriately.

We consider the ENA option to be the best option for ensuring that regulated suppliers are able to fully recover their allowable revenues. Full recovery is particularly important given the Commission does not provide any allowance for uncertainty (other than adoption of the 75th percentile for WACC).

The Commission could limit wash-up to pass-through and recoverable costs rather than the entire allowable revenues. The ENA option would then, in effect, be equivalent to Vector's proposal.

The Commission has expressed concern that Vector's proposed approach (and, therefore, presumably the ENA's) provides "distributors with a substantial degree of flexibility in how they set the transmission component of prices" and "that this may give distributors too much flexibility in calculating the annual amount the will recover for transmission charges".[143]

This concern is readily addressed without having to adopt the Commission's hybrid option.

There are various safe-guard options the Commission could adopt; including to avoid the risk of regulated suppliers systematically over-recovering in earlier years.

The ENA has proposed introducing a penalty where variances between allowable notional revenue and notional revenue exceed a specific threshold. Taken to the extreme, the Commission could allow for wash-up only within a certain band of tolerance; i.e., the Commission's suggested "limit on the transmission balance within a designated percentage range of known (i.e., lagged) quantities)".[144]

Another option would be to apply an asymmetric time-value of money; i.e., the discount rate applied for over-recovery could exceed the discount rate applied for under-recovery. This would provide an incentive for regulated suppliers to err on the side of under-recovery.

If consumer welfare is an issue that is constraining the extent to which the Commission is willing to allow wash-up, we would note that the interest rate(s) for under and over-recovery could be set at

If there was any merit in Genesis Energy's proposal then this would be something that could usefully be discussed between the Commission and the Electricity Authority in relation to retailer obligations in respect of their own price changes; particularly in light of concerns about the extent to which electricity retailers pass-through reductions in regulated distribution prices.

[142] Electricity Networks Association, Submission on default price-quality paths from 1 April 2015 for 17 electricity distributors: process and issues paper, 30 April 2014, paragraph 134.

[143] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.52.

[144] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.53.2.

a level so that consumers would actually be better off if regulated suppliers under or over-recover as it would reduce the NPV of their network charges.

We would expect that use of financial penalties (slightly higher interest rate for over-recovery) would better serve consumer interests than arbitrary quantified limits on under/over-recovery.[145]

We accordingly consider the ENA wash-up option, and/or Vector's proposed approach, warrant further consideration by the Commission.

If the Commission decides to reject the ENA and Vector options, even with the safe-guards we have suggested, then we would support the Commission's hybrid as a third-best option.

The Compliance Requirements Reasons Paper states that, under the hybrid, "In order to comply with the price path, the transmission balance at the end of the regulatory period must be less than or equal to zero. Under the proposed approach, a negative balance (of unrecovered charges) is not carried over into the next regulatory period".[146] We cannot understand why the Commission would propose this. The Commission provides no explanation to comment on. The Commission has provided for claw-back to extend beyond a single regulatory period, so why not other recoverable costs?

Effectively, it is as if the Commission's proposals apply for four years only, rather than the full five years of each regulatory period. Aurora supports allowing a negative balance (of unrecovered charges) to be carried over into the next regulatory period, and also supports a positive balance (of over-recovered charges) to also be carried over.

In summary, our preference is for the Commission to adopt a wash-up mechanism where unders and overs are recompensed in subsequent periods (including subsequent regulatory periods). We do not see any downside to consumers from this approach, so long as an appropriate interest rate(s) is applied to any under or over recovery.[147]

145 Consumers could actually then prefer it if their distributor over-recovered pass-through and recoverable charges (Vector option) or allowed distribution revenue (ENA option).

146 Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.50.

147 As per the approach taken to claw-back.

Ensuring ACOT payment arrangements remain practicable and are to the long-term benefit of consumers

Clause 3.1.3(1)(f) of the Electricity Distribution Services Input Methodologies Determination 2012 provides that avoided cost of transmission (ACOT) payments are a recoverable cost, and it is permissible to recover "an amount equal to transmission costs that an efficient market operation service provider (as 'market operation service provider' is defined in the Electricity Industry Participation Code) is able to avoid as a result of the connection of distributed generation determined in accordance with Schedule 6.4 of Part 6 of the Electricity Industry Participation Code".

The Commission proposes to amend clause 3.1.1(1)(f) to "a **distributed generation allowance**, …" where **distributed generation allowance** means any positive allowance for costs incurred and amounts payable or negative allowance for amounts receivable in relation to the regulation of avoided transmission charges arising from distributed generation, including embedded or notionally embedded generation, made under:

"(a) Schedule 6.4 of Part 6 of the Electricity Industry Participation Code, or

"(b) the Electricity Industry Act 2010."

These changes address a number of issues:

- They avoid the potential for conflict between "an amount equal to transmission costs that an efficient market operation service provider (as 'market operation service provider' is defined in the Electricity Industry Participation Code) is able to avoid as a result of the connection of distributed generation" and Schedule 6.4 of Code that could arise if Schedule 6.4 is amended.
- They correct the current error of referring to "market operation service provider" [there is no such thing] rather than "electricity distributor"; and
- They 'future proof' against changes where ACOT payments are not necessarily specified by the Authority under Schedule 6.4 of the Code.

There are some potential issues that the Commission should consider though.

Any changes to ACOT payment arrangements need to recognise/grandfather existing ACOT contractual arrangements between distributors and distributed generators. Otherwise, distributors could end up in a situation where, through no fault of their own, they are making payments based on pre-existing ACOT payment Code requirements (until contract expiry) that are not able to be fully recovered.

What would happen if the Commission and Electricity Authority had different views as to whether a distributor's ACOT payments complied with the Electricity Authority's Code?

Aurora does not believe that the current Code provisions for ACOT payments are to the long-term benefit of consumers, as they provide that the distributed generator receives the full benefit of any avoided transmission, only pays incremental cost, and does not have to contribute to the distributors fixed and common costs. This means consumers do not share any of the efficiency benefits of distributed generation, contrary to the purpose in section 52A(1)(c) of Part 4 of the Commerce Act.

Furthermore, what would happen if the Electricity Authority amended the existing Distributed Generation/ACOT payment provisions is Schedule 6.4 of the Code in a way that is not, and/or the Commission was not satisfied is, practicable to comply with or to the long-term benefit of consumers?

For example, Aurora considers that the correct interpretation of the current Schedule 6.4 of the Code is to base the ACOT payments on the transmission charges distributors actually avoid due to distributed generation.

The Electricity Authority has expressed concerns about basing ACOT payments on actual avoided transmission charges rather than the (unknown) costs Transpower would avoid. (This will be different to the extent that the TPM charges are not fully cost reflective.)

In the Electricity Authority's ACOT Working Paper it made the following comments:

> *"A practice has arisen whereby a majority of distributors calculate their ACOT payments according to the transmission charges they avoid (as a result of the operation of DG on their network) rather than on the basis of the economic costs avoided.*[148]
>
> *The Authority considers that an approach in which payments to DGs are based on avoided economic costs, rather than avoided transmission charges to the distributor, would better reflect the Authority's statutory objective2 "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers". This would include consideration of avoided costs to both transmission and distribution.*
>
> *On this basis, the Authority's preliminary view is that the majority of ACOT payment schemes could be improved through:*
>
> - *a greater focus on economic costs rather than the pass through of avoided transmission charges to consumers*
> - *a greater consideration of any benefits accruing to distribution networks, if any."*[149]

In Aurora's view it would be entirely impractical to base ACOT payments on Transpower's actual avoided costs. We do not know what Transpower's actual avoided costs are, and could not reasonably be expected to know. All we can do is respond to Transpower's transmission charges. Market participants should be able to assume that responding to pricing signals will lead to more efficient outcomes.[150]

The Commission should liaise closely with Electricity Authority to ensure appropriate delineation of responsibilities, and that both regulators are satisfied any prospective changes to Schedule 6.4 of the Code would satisfy the purposes in section 52(A)(1) of the Commerce Act and section 15 of the Electricity Industry Act. In particular, any arrangements need to reflect it is the Commission's responsibility to approve the ACOT for treatment as a recoverable cost amount not the Electricity Authority.

This issue highlights some of the downside of having two separate regulators dealing with interrelated aspects of economic regulation of electricity distribution.[151]

Practical implications of Commission approval of avoided transmission

The Commission has proposed "updating the recoverable cost term relating to avoided transmission charges as a result of distributed generation (also referred to as embedded generation) to require Commission approval"[152].

[148] Electricity Authority, Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation, 19 November 2013, paragraph 1.2.

[149] Electricity Authority, Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation, 19 November 2013, paragraphs 1.16 and 1.17.

[150] In this respect, we note that Transpower is presently undertaking an operational review of the TPM and has identified it may desirable to amend the RCPD interconnection charges to make them less avoidable/more fixed. This could result in better alignment between avoided transmission charges and Transpower's actual avoided transmission costs.

[151] The interrelationship between sections 32(2)(b) and 34(1)(a)(v) of the Electricity Industry Act is particularly clumsy.

[152] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 3.76

The Commission should understand that the approval process has real implications for EDBs, and the Commission, in terms of timeliness of response. Distributors are normally advised of changes to transmission expenses in November annually. Most EDB's use-of-system agreements with electricity retailers specify that prices changes must be advised at least 40 working days before they take effect. In Aurora's case, we aim to have price changes approved by the Board in late January, with price changes notified to retailers at the end of January/start of February.

It is likely that, in order for Aurora to complete the re-pricing process within contractual and governance timeframes, we would require Commission approval by the end of December annually.

Approval of Aurora's avoided transmission charges for the first assessment period is likely to be much compressed. Distributors have been advised by Transpower[153] that they are unlikely to advise pricing for the first assessment period until 15 December 2014, as a result of the Commission's proposal to defer the determination date of the regulatory WACC by one month[154].

Aurora's view is that the Commission must be mindful of the contractual and governance constraints on distributors, with respect to price changes, and must be confident that it is able to adequately resource its proposed approval process, and provide responses to distributors in a timely manner.

[153] Transpower, Customer Update, 7 August 2014
[154] Proposed amendment to the WACC determination date for electricity lines services, including Transpower, 4 August 2014

12 CUSTOMISED PRICE-QUALITY PATHS

CPP windows should be wider and more flexible

The Commission is proposing to limit CPP applications to two narrow (one week each) windows. The rationale is that “the Act allows us to prioritise applications where we receive more than four in one year. In order to undertake this prioritisation exercise, we need all the applications to be submitted at the same time”.[155]

Aurora considers that this unduly constrains when EDBs can apply for CPPs, and is not in the long-term interests of consumers.[156]

The Commission should also be mindful that the limited windows come at a cost.

They could result in EDBs having to wait up to an extra six months (on top of the time it took to prepare the CPP) to submit a CPP application. Given that the Commission does not fully compensate regulated suppliers for foregone revenue during the period between a catastrophic event, such as the Christchurch earthquakes, and the CPP determination, this narrow window could add considerable cost and risk for EDBs.

In years where there are no more than four CPP applications for the same type of regulated good or service, the imposition of narrow windows to enable the Commission to prioritise applications has no value. This is all years since the new Part 4 was introduced as there has only been one CPP application.

In our view, the costs of delay (up to six months) outweigh the hypothetical benefits of being able to prioritise CPP applications on a different basis to ‘first come, first served’.

At the very least, we suggest that the Commission widens the window beyond one-week (say to a month); and/or provide a provision allowing exemptions from the CPP windows; e.g., if other EDBs supported an EDB being able to apply for a CPP outside of the normal windows.

The Commission could also consider adopting a prioritisation rule allowing applications to be received after the end of the two windows, but before the end of the year, with any such applications prioritised on a first come, first served basis.

[155] Commerce Commission, Draft reasons paper, Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, 18 July 2014, paragraph 8.5.

[156] Prioritisation should only be applicable for electricity distribution, as there aren’t four gas distribution or four gas transmission businesses.

13 NEXT STEPS

Aurora considers that the priority matters for the Commission, between now and the November 2014 final determination of the April 2015 EDB DPP resets, should include the following:

Part 4 framework/High level decision making

- **Evidence-based decisions:** Make sure that the assumptions/judgements/decisions the Commission makes are fully evidence based. The High Court Part 4 IM Merit Appeal decision should be seen as lifting the standard of evidence needed to support regulatory decisions, and the WACC percentile consultation material should be seen as a precedent for the level of evidence-based support required for decisions that have substantive impacts on regulated suppliers.

- **"Reasonable investor expectations":** Test whether the decisions that the Commission is making are consistent with "reasonable investor expectations", in the same way as the Commission is doing for decisions on TSLRIC price control of Chorus' UBA and UCLL copper services.

Specific matters to consider to ensure EDBs can reasonably expect to recover their costs

- **Revenue growth forecast:** Base revenue growth forecasts on historic trends for each EDB, rather than the NZIER regional GDP growth forecasts.

- **Opex base year:** Adopt 2013/14 as the opex base year/test whether 2013/14 opex was "atypical"/reflected gaming, or simply reflected the upward trend and year-on-year volatility in opex;

- **Capex forecasting error/systematic bias testing:** Undertake more rigorous analysis to determine whether (and whom) any EDB's capex forecasts are systematically-biased upwards, and reviewing which EDBs, if any, should be subject to a 110% cap on historical average capex. This should include consideration of whether their capex forecasts for 2015-2020 are robust enough to rely on.

- **Option of treating capex as a recoverable cost:** Consider providing EDBs with the option of having their capex for 2015-2020 treated as a recoverable cost, if they plan to spend more than the proposed caps would allow them.

- **Low cost forecasting:** Make sure that judgements on capex/opex are based on an understanding of EDB AMPs, and not just the forecasting numbers in the AMPs, and reflect information readily available to the Commission; e.g., Strata's assessment of the impact of changes Aurora has made to address service quality issues on opex/capex requirements.

- **Partial productivity adjustment:** Either include a negative partial productivity adjustment to opex (there is sufficient evidence to support this) or remove the provision from the opex forecasting formula, and don't apply it in any future resets.

- **Cross-sectorial consistency:** If the Commission identifies shortcomings with the WACC IMs, as part of its deliberation on setting TSLRIC prices for UBA and UCLL prices, it should consider amending the WACC IMs at the same time. We agree with Wigley & Company on this point.[157]

[157] Wigley & Company, Cross-submission to the Commerce Commission in response to the Commission's expert reports on the cost of capital for the UCLL and UBA price reviews, 4 August 2014.

- **Service quality performance standards/revenue-link:** The Commission should revise aspects of its proposals, including the proposal that SAIFI would replace SAIDI as the trigger for normalisation. The Commission should also ensure service quality performance standard setting is symmetric and equally takes into account performance above and below previous standards/ensure that any increase in performance standards is not uncompensated.

We recognise that the Commission is likely to prioritise its decision on WACC percentile, and this is reflected in the amount of time and resource it has expended on the matter relative to all other aspects of the DPP reset.

Aurora considers that the priority should be, first and foremost, ensuring investors/EDBs can reasonably expect to recover at least a normal return on their investment over the 2015-2020 regulatory period. This is far more important than whether the WACC percentile should be amended from 75^{th} to 67^{th} percentile or ‘nice to have’ options such as s 54Q mechanisms. While we fully support initiatives to improve efficiency incentives etc., it should be recognised that the Part 4 regime is still in a transitional stage from initial implementation.

14 POST-RESET PRIORITY WORK AREAS

Aurora is pleased that the Commission's operation of the Part 4 regime is evolving, even with the short period between the initial and second EDB DPP resets. We look forward to the Commission advancing the regime further for the 2020 reset, and beyond. Aurora fully expects that the operation of the Part 4 regime will evolve, and will become increasingly more sophisticated. This is typical with more mature regulatory regimes in overseas jurisdictions that have been in existence a lot longer than the current Part 4.

The Commission, for example, has noted "Regulators in other jurisdictions have also made incremental improvements to incentive mechanisms as their regulatory regime matures. In the United Kingdom, for example, Ofgem first introduced an equalised incentive on in 2009. More recently, the Australian Energy Regulator has introduced an incentive mechanism similar to the EBSS for capital expenditure in order to strengthen incentives for suppliers to deliver capital projects efficiently. The Capital Expenditure Sharing Scheme results in suppliers retaining 30% of any underspend or overspend".[158]

As the proverb says "Rome wasn't built in a day".

More attention should be given to s53P(3)

Aurora would also like to see greater attention given to the choice between reset and roll-over of existing prices when the Commission undertakes its future DPP resets.

The current basis for such a review seems relatively one-dimensional, and comes down simply to whether the Commission estimates regulated suppliers would earn supranormal profits in the next regulatory period if it does not reset prices. The DPP regime may be CPI-X but the Commission's Starting Price Adjustment methodology is based on rate of return regulation.

We preferred the approach, adopted by the Commission in the previous Part 4A regime, of removing supranormal profits/sharing efficiency gains over time (the Commission rejected adoption of a Starting Price Adjustment under Part 4A).

Aurora does not believe the Commission should take an all or nothing approach to price resets, or that 100% of efficiency gains from the previous regulatory period should be removed at the time of the next reset.

The choice between roll-over (no removal of supranormal profits) versus reset (based on the current full removal of projected supranormal returns) need not be seen as discreet, either-or options. The Commission should, for example, consider adoption of Vector's Staggered Sharing Mechanism proposal as a middle ground option; i.e., the Staggered Sharing Mechanism would remove part/most projected supranormal profits arising from efficiency gains in the previous price control period but not all, increasing the reward for efficiency gains and, over the medium to long-term, ensuring greater efficiency gains are available to be shared.[159]

We consider this warrants further attention, subject to the Commission's statement, made at the last reset, that "We have not applied a staggered sharing mechanism at this reset because incentive mechanisms only provide benefits to consumers when they have been signalled to suppliers up front. That is not the case for any efficiency gains that were achieved prior to the start

[158] Commerce Commission, Proposed amendments to input methodologies: Incremental Rolling Incentive Scheme, 18 July 2014, footnote 21.

[159] We recognise there is scope for a Staggered Sharing Mechanism to both complement and substitute for aspects of IRIS e.g. IRIS could mimic the Staggered Sharing Mechanism by extending the period that regulated suppliers are able to hold onto efficiency gains beyond 5 years. They are not perfect substitutes, however, as the Stagger allows for more graduated sharing (rather than all or nothing) and is less complex than an IRIS.

of this regulatory period".[160] This would suggest that if a stagger was to be introduced, it should be done so, in advance, to take effect at the 2020 reset.

Efficiency incentives will be an ongoing area for improvement

While we acknowledge that the Commission is proposing material improvements for the 2015 reset, we do not believe the Commission has yet done enough to get the balance between short-term pass-through of efficiency gains, and maximising the level of future efficiency gains available to be shared with consumers.

We also consider, consistent with the High Court commentary on the WACC percentile and the need for Part 4 decisions to be evidence-based generally, that the Commission should investigate what the optimal retention factor should be.[161] We do not consider the observation that a retention factor of 35% is "Comparable to strength of the incentive that occurs naturally in the first year of a 5 year regulatory period" or "Consistent with the strength of the incentive that is favoured by the Australian Energy Regulator"[162] to be sufficient.

We agree with Vector that "There will be opportunities to evolve the operation of Part 4, including in relation to efficiency incentives, and to leverage off the experience and operation of economic regulation in other jurisdictions"[163] and "There is no single "silver bullet"[164] solution to efficiency incentives. Aurora agrees with Vector that "a package of complementary incentive mechanisms would be desirable, for example: IRIS, staggered pricing mechanism and an S-factor".[165] We think the Commission should prioritise consideration of optimal retention factors for sharing efficiency gains between regulated suppliers and consumers, and what analysis and empirical evidence could be obtained to support a decision on the matter.

Aurora considers that menu regulation, and Vector's Stagger, are options worth considering for the 2020 reset. Menu regulation has the potential to significantly address the Commission's concerns about regulated suppliers gaming their capex forecasts, and could also help ensure efficient trade-offs are made between opex and capex. We fully acknowledge that while Castalia, in particular, has presented strong arguments in favour of menu regulation it is a complex matter and may not be realistic for the 2015 reset.

Revenue-linked service quality scheme

It is evident from the Commission's 2015 DPP reset proposals, that it is only taking tentative steps towards introduction of a price-service quality link. It probably makes sense to take a cautious approach the first time round, particularly as there are only two years between the initial and 2015 DPP resets, which limits the time and resources the Commission has for considering such a mechanism. We would welcome a more comprehensive review of such mechanisms for the 2020 reset, with the added advantage of experience with the initial basic version the Commission is proposing.

It would be desirable if the Commission could complete this exercise well before the determination of the 2020 reset, so that EDBs have time to review the implications of the enhanced service reliability incentive scheme for how they should operate their businesses. The more complex or sophisticated the scheme the more time that would be desirable.

[160] Commerce Commission, Revised Draft Reset of the 2010-15 Default Price-Quality Paths, 21 August 2012, paragraph 156.

[161] The Kiwi Share Obligation includes a 100% retention factor, with CPI-0% set for perpetuity so Chorus/Telecom retain all efficiency gains, and there are zero benefits to consumers.

[162] Commerce Commission, Proposed amendments to input methodologies: Incremental Rolling Incentive Scheme, 18 July 2014, paragraph 67.

[163] Vector, Submission to the Commerce Commission on Incentives for Suppliers to Control Expenditure During a Regulatory Period, 21 October 2013, paragraph 9.

[164] Vector, Submission to the Commerce Commission on Incentives for Suppliers to Control Expenditure During a Regulatory Period, 21 October 2013, paragraph 15b.

[165] ibid

We would like to emphasise that while the Commission's proposal adopts a "cautious" approach, it needs to start somewhere. Pursuit of the perfect should not be the enemy of the good.[166]

Consumer willingness to pay/VoLL

We agree with the Commission's arguments that "in principle, the incentive rate should reflect consumers' willingness to pay for changes in service reliability, as suggested by Vector. However, given that revenue at risk is set at 1%, applying an incentive rate comparable to a type of value of lost load measure would result in a very narrow band between cap and collar for many distributors".[167]

This is a matter that the Commission should revisit for future (2020 and beyond) resets, in conjunction with the percentage revenue at risk; e.g., 5% revenue at risk, based on VoLL, may make sense if the revenue-linked quality incentive scheme is successful.

We suggest that the Commission liaise with the Electricity Authority on the establishment of an appropriate VoLL that could potentially be used for future resets. The Authority has established a VoLL of $20,000/MWh, and this is incorporated in the Electricity Industry Participation Code.[168] The Commission proposes to use this VoLL value for setting the quality incentive rate in Transpower's IPP.

Last year, the Authority completed a study on VoLL, which produced a national VoLL estimate of $50,031/MWh.[169] This brings into question whether the $20,000/MWh VoLL should be relied on, though the Authority has not formed a public view on the merit of the alternative VoLL calculation, and has not consulted on this. Care needs to be taken to ensure that the benefit to consumers of service quality improvements are not overstated, as this could result in over-investment/expenditure. This is not a matter that we would expect the Commission and Electricity Authority to be able to resolve with the timeframe of the 2015 EDB DPP reset, even if the Commission was planning on applying VoLL to the revenue-linked service scheme.

[166] The section of this submission "Revenue-linked service quality scheme" discusses some potential areas for future development.

[167] Commerce Commission, Proposed Quality Targets and Incentives for Default Price-Quality Paths from 1 April 2015, 18 July 2014, paragraph 6.9.

[168] Clause 4 of Schedule 12.2 of the Electricity Industry Participation Code 2010.

[169] Electricity Authority, Investigation into the Value of Lost Load in New Zealand: Report on methodology and key findings, 23 July 2013, paragraph C.39.