From the Electricity Networks Association

Submission on proposed default price-quality paths for electricity distributors from 1 April 2015

Final

15 August 2014

The Electricity Networks Association makes this submission along with the explicit support of its members subject to Default Price-Quality Path regulation, listed below.

Alpine Energy Ltd

Aurora Energy Ltd

Centralines Ltd

Eastland Network Ltd

Electricity Ashburton Ltd

Electricity Invercargill Ltd

Horizon Energy Distribution Ltd

Nelson Electricity Ltd

Network Tasman Ltd

Orion New Zealand Ltd

OtagoNet Joint Venture

Powerco Ltd

The Lines Company Ltd

Top Energy Ltd

Unison Networks Ltd

Vector Ltd

Wellington Electricity Lines Ltd

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1. Introduction

1. The Electricity Networks Association (ENA) appreciates the opportunity to provide feedback to the Commerce Commission (the Commission) on the 2015 DPP Main Policy Paper.[1]

2. This submission is also supported by the following papers prepared by Pacific Economics Group (PEG) which were submitted on 7 August:

    a) Productivity Trends of New Zealand Electricity Distributors, June 2014

    b) Review of Economic Insights' Report Electricity Distribution Productivity Analysis: 1996-2013, August 2014.

3. The ENA has also presented today a related submission in response to the Commission's Low Cost Forecasting Paper.[2] We will also present submissions by 29 August on a number of other related consultations, which were published on 18 July 2014.[3]

4. The ENA represents the 29 electricity network businesses (ENBs) in New Zealand.

1.1 Summary

5. For the purpose of setting the 2015 DPP, the ENA, with regards to specifying the price limits:

    a) Supports resetting price paths on the basis of current and projected profitability.

    b) Acknowledges the plan to introduce incremental improvements to previous forecasting methods. However we submit that it is necessary to test previous forecasts against outturns before finalising the forecasting models and we encourage the Commission to consider our accompanying submission on Low Cost Forecasting Approaches in this respect.

    c) Notes that it is important that price limits are set with sufficient consideration of the obligations which must be met by ENBs in delivering electricity lines services, while ensuring the health and safety of staff, contractors and the public.

    d) Notes that in the first year of the price path (2013/14) all ENBs have not achieved the specified WACC. While some ENBs choose to price below their

[1] Commerce Commission, Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015, 4 July 2014

[2] Commerce Commission, Low Cost Forecasting Approaches for Default Price-Quality Paths, 4 July 2014

[3] Refer: http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality-path/default-price-quality-path-from-2015

price paths, higher than forecast opex, lower than forecast CPI, and lower than forecast volumes are some of the other reasons which have contributed to the lower returns than predicted. The ENA considers that this context is relevant to determining the forecasting methods for the next regulatory period, and in particular, demonstrates that the Commission's forecast models have not delivered prices that have enabled ENBs to cover their costs.

e) Supports the inclusion of allowances for forecasting uncertainty in DPP price paths and notes that the Commission's analysis suggests 11 of 16 ENBs may be sufficiently incentivised to apply for a CPP due to forecasting error. The ENA considers this outcome is not consistent with the design of the DPP/CPP regulatory framework and submits that forecasting methods must be improved (and our suggestions are included in our accompanying Low Cost Forecasting Submission).

f) Considers that in respect of the productivity-based rate of change the Commission should set the X factor and associated opex PFP at negative values as indicated in the PEG report (and supported by the empirical evidence in the EI report prepared for the Commission). A conservative value is appropriate on the balance of risks between ENBs and consumers and there is no relevant quantitative evidence that suggests a higher value (such as zero) is warranted in the New Zealand context. While the ENA recognises that the Commission is entitled to exercise judgement in making its decisions, given that there is strong and consistent evidence of a long-term decline in measured opex PFP and TFP from two independent experts, the Commission must provide a robust empirical base of research and evidence to depart from this expert view. To do otherwise leads to a perception that the Commission has predetermined the outcomes to lead to lower consumer prices, behind the façade of an independent empirical process.

g) The ENA submits that the Commission should adopt a -2% per annum opex partial productivity factor, consistent with the evidence in the PEG report. The analysis of PEG should be preferred because it is consistent with the Commission's broader forecasting approach (e.g., use of all-industries LCI, and opex forecast drivers) whereas the EI analysis is not.

h) Supports the use of alternative rates of change to mitigate initial price steps, however considers that the proposed method assumes an initial price step which is too low and which does not adequately consider the gap between the price path and underlying building blocks which emerges at the end of the regulatory period, when large alternative rates of change are adopted.

i) Suggests ENBs which are facing alternative rates of change are consulted about their preferred price path profile before final price paths are determined.

6. With regards to pass through and recoverable costs, the ENA:

a) Supports proposals to amend the DPP to allow ENBs to recover pass through and recoverable costs in full.

b) Supports proposals to introduce a new recoverable cost to allow the recovery of the shortfall in revenue which applies to some ENBs as a result of price caps applied in the current regulatory period.

c) Notes that it is important that ENBs are able to recover these costs in full on a timely basis, including if necessary, recovering costs incurred in one regulatory period, in the following regulatory period.

7. With regards to targets and incentives for service quality, the ENA:

a) Supports in principle a move to a quality incentive scheme, however we note that determining the key features of the scheme are critical to its success.

b) Notes that the current proposal is currently being considered by members and will be responded to in forthcoming submissions on the QoS Companion Paper.

c) Has developed success criteria to better evaluate the range of options available (including the option of retaining a pass fail quality standard) and encourage the Commission to consider these criteria before finalising the DPP quality standard.

d) Has particular concern with the proposed approach to normalisation, compliance and enforcement, and the pro rata adjustments for prior period breaches.

e) Notes that the proposed scheme is heavily influenced by the frequency of major event days. The ENA considers that a scheme which is unduly influenced by the weather does not meet the underlying objective of recognising/penalising systematic improvements/declines in performance.

f) We consider that these must be addressed before a revenue incentive scheme can be introduced successfully. Absent these changes, retention of the current pass/fail model is the appropriate alternative.

8. The ENA submits for other (non-quality of supply) incentives in the DPP:

a) The Commission's proposed D-factor minimises compliance costs; includes a time value of money adjustment for the lag between the revenue foregone and the recoverable cost adjustment; minimises uncertainty over eligibility through clear, consistent decisions and frameworks. Alternatively a volume wash-up as proposed in our response to the Process and Issues Paper could be implemented. This would adjust for all volume variations between the DPP forecast and actual outturn beyond a certain threshold. The adjustment factor could be treated as a recoverable cost.

b) A wash-up of depreciation and the return on capital in the following regulatory period is introduced.

c) While the Commission's intention to provide guidance on specific examples of the definition of "electricity lines services" is welcome, a less case-specific approach to clarifying the scope of investments that are included in "electricity lines services" should be pursued. This would enable ENBs to take up technological change and innovate.

d) In principle, the ENA supports equalising incentives relating to opex and capex over time, but:

i. We will comment further on the specifics of the opex incentive mechanism in our submissions on the IRIS papers.

ii. The capex incentive mechanism retention factor should be set to 5% within a band between the cap and the ENB's AMP forecast. Outside this band, the retention factor should be set to 10%. The mechanism should be neutral on the precise timing of capex investment.

9. The ENA recommends that when reconsidering of a price-quality path following a catastrophic event:

a) DPP price paths and quality standards are able to be reopened.

b) A recoverable cost term is included to provide for the financial impact between the event and the reset price path coming into effect.

c) Further consideration is required as to the possible impact of a catastrophic event on the proposed quality, energy efficiency and demand side management and expenditure financial incentive schemes. Suppliers should be able to elect to suspend these schemes following a catastrophic event, and any additional expenditure allowances must consider the net impact on suppliers and consumers after incentive rewards/penalties have been taken into account.

d) The regulatory response to a catastrophic event should consider all of the risks faced by suppliers, including demand risk, prior to and following a reset.

e) The purpose of the percentile uplift to the cost of capital is not, as suggested in earlier consultations, to provide compensation for catastrophic event risk and the ENA submits that the a specific cashflow allowance must be provided to compensate ENBs for the expected value of demand reductions following a catastrophic event. Given the proposal that lower demand levels following an event must be borne by investors and the WACC does not include allowance for asymmetric risks, there must be *ex ante* compensation for such risks in cash flows.

10. The ENA also considers that the recoverable costs term should be extended to include potential remedies which may be required for other (non-catastrophic) re-opener events.

11. Should an ENB purchase assets from Transpower:

a) The ENA supports the recoverable cost incentive for asset transfers from Transpower which allow avoided transmission charges to be recovered through prices for a period of five years.

b) The proposal is to prescribe how the avoided cost is calculated. ENA members are concerned that the proposed new approach will inadvertently exclude legitimate avoided transmission costs, and be impractical to achieve in practice.

The current approach achieves reasonable outcomes and we consider it should be retained.

c) Purchases prior to the next regulatory period should be fully reflected in forecast costs when setting the price path. The current proposals do not adequately provide for opex (and can be improved by using ENB forecasts) and impose unreasonable constraints on capex which do not allow for differences between the capex plans of ENBs and Transpower (which compromise the incentive)

d) The costs associated with purchases during the regulatory period are addressed through the recoverable cost incentive, however the proposed specification of that incentive does not provide for all of the avoided costs to be recovered.

e) The ENA considers that avoided new investment charges that would have arisen during the five year window, due to additional investment in the assets which have been transferred are legitimate recoverable costs, consistent with the intent of the incentive.

12. The ENA also notes the wider capex wash-up proposed for FY15 and agree accuracy in RAB at the beginning of the regulatory period is important. We note that improved accuracy could be achieved in other forecasts used to set the DPP price path, where the most recent information available is not used, and/or, other wash-ups could be considered.

13. The ENA also recommends

a) The uncertainty that currently exists about what happens at the end of a CPP should be reduced to ensure the DPP/CPP regulatory model is able to operate effectively. This can be achieved by further clarification as to the process and criteria that will be applied to determine the DPP price and quality standards at the end of a CPP. This clarification should be provided as soon as possible, and ideally, alongside the DPP Determination.

b) It will also reduce regulatory uncertainty if the Commission clarifies whether and how Orion's performance within this period will be taken into account when setting the next DPP for other businesses.

14. The ENA recommends that the Commission, in order to enable ENBs to address the public safety issues arising in relation to customer service lines:

a) Include a recoverable cost category for services implemented in relation to customer service lines, with a provision for pre-approval of any proposed cost recovery by the Commission.

b) Absent such a provision, the Commission will discourage ENBs taking proactive steps to manage a looming public safety concern as service lines age.

15. We provide more detailed comment on these points in the body of our submission.

16. The ENA's contact person for this submission is:

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2. Specifying price limits

2.1 Approach to setting starting prices

17. The price paths applying to non-exempt ENBs are due to be reset by 30 November 2014, to apply from 1 April 2015, for a period of five years. A price path will not be reset for Orion New Zealand, which is currently subject to a customised price-quality path (CPP).

18. The ENA has previously acknowledged and supported the decision to reset prices with reference to current and projected profitability. The Main Policy Paper indicates that after consideration of submissions on the Process and Issues Paper[4], it is intended that price paths will be reset after considering incremental improvements to the existing approaches to determining current and projected profitability (ie: those adopted for the 2012 DPP reset).

19. While the ENA supports this approach in principle, as we have previously submitted, we consider that it is necessary to test previous forecasts against outturns before finalising the forecasting models. We are disappointed that our previous submission on this matter has not been acknowledged or responded to. The ENA and individual members have consistently submitted that the Commission must evaluate the performance of its forecasting models and demonstrate that any chosen forecast model is the most likely of all available options to deliver a price path that covers ENBs' reasonable and efficient costs. There is now strong evidence that the Commission's models for opex and real revenue growth perform poorly, which the Commission must not continue to ignore.

20. In our accompanying submission on the Low Cost Forecasting Approaches we include observations about the performance of the forecasting methods used when resetting the DPP price paths in 2012. We have used this analysis to assist us to form our views on the proposed methods for the 2015 reset. We encourage the Commission to consider the empirical evidence we have compiled in this respect before finalising the 2015 DPP reset decision.

2.1.1 Performance under the current price path

21. Before addressing the proposed approach to determining price paths for the next regulatory period, it is useful to consider how businesses have performed in the current regulatory period.

22. Figure 1 below shows the regulatory returns reported by each non-exempt ENB since the price path was reset (using the current and projected profitability approach), with reference to the DPP vanilla WACC of 8.77%.

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

23. There are a number of reasons why a business will report returns which differ to the target WACC in any one year. These include the smoothing which is inherent in price paths, choosing to price below the price path, claw-back allowances, efficiency gains and differences between forecast and actual outturn for opex, capex, CPI, sales volumes and other forecast items.

24. The table below shows the regulatory returns actually achieved by businesses in FY13 and FY14 under the DPP price cap. As the current ID ROI formula is not consistent with the formula used to derive the DPP allowable revenue, disclosed ROIs have been restated to enable comparison with the target 8.77% WACC used when setting the price path.

Figure 1: Non-exempt ENB ROI (FY13 and FY14)

Figure 1	2013		2014	
	As disclosed (%)	Recalculated consistent with DPP BBAR (%)	As disclosed (%)	Recalculated consistent with DPP BBAR (%)
Alpine Energy	2.88	3.15	3.23	3.47
Aurora Energy	6.99	7.40	7.08	6.78
Centralines	2.59	3.18	3.51	3.72
Eastland Network	6.28	6.62	5.77	6.45
EA Networks	5.81	5.08	7.39	6.83
Electricity Invercargill	5.36	6.07	6.89	7.43
Horizon Energy Distribution	6.40	7.15	6.57	7.40
Nelson Electricity	9.38	10.08	7.70	8.14
Network Tasman	8.91	6.94	9.03	6.78
OtagoNet Joint Venture	6.99	7.73	7.57	7.97
Powerco	6.44	6.58	7.13	7.11
The Lines Company	4.18	5.12	5.41	6.07
Top Energy	3.69	4.56	3.83	4.49
Unison Networks	5.64	6.35	5.83	5.33
Vector	7.67	8.31	7.19	7.22
Wellington Electricity Lines	6.79	7.70	7.71	8.13

25. We note that all non–exempt ENBs have not achieved the target level of returns within the first of the two years of the current price path. We acknowledge that 4 ENBs have had their revenues capped below a level necessary to achieve target returns in the current regulatory period, due to concerns about price shocks, and others have chosen to price below their price paths.

26. However we understand that higher than forecast opex, lower than forecast CPI, and lower than forecast volumes are reasons which have contributed to the lower returns than predicted. The ENA considers that this context is relevant to determining the forecasting methods for the next regulatory period: the Commission's proposals to use the same methods and adopt the same assumptions (e.g., opex PFP, static energy use

per consumer) are highly likely to lead to the same outcome: below WACC returns. The ENA submits this is not sustainable and will prevent the achievement of the objectives of Part 4.

2.1.2 Specifying price limits

27. DPP price limits are specified net of controllable costs (currently specified as recoverable or pass through costs). Thus DPP price limits are intended to ensure that suppliers focus on the costs they are able to control, with incentives to outperform the underlying cost allowances.

28. We note that the Main Policy Paper acknowledges the obligations on ENBs to achieve certain performance outcomes, including through the DPP quality standards, other legislative requirements (such as the Consumer Guarantees Act, Electricity Act) and other commercial obligations such as guaranteed performance standards. Health and safety objectives are also of primary concern to all distributors. Accordingly it is important that price limits are set with sufficient consideration of the obligations which must be met by ENBs in delivering electricity lines services, while ensuring the health and safety of staff, contractors and the public.

Setting customer prices

29. The DPP price path determines a weighted average price cap which sets the limit as to the total line charge revenue (net of pass through and recoverable costs) which may be recovered by non-exempt ENBs. Accordingly the DPP does not set limits on individual customer prices for electricity lines services.

30. The ENA acknowledges the role of pricing methodology disclosures and associated monitoring by the Electricity Authority in complimenting the DPP price path in this respect.

2.2 Allowances for forecasting uncertainty

31. As the DPP is intended to be a relatively low cost regulatory mechanism, when compared to a CPP for example, the methods adopted for resetting the DPP are less focussed on supplier specific information than a CPP. Accordingly, the availability of a CPP is an important component of Part 4 regulation for non-exempt ENBs, as it provides an alternative option for establishing price and quality paths which reflect business specific circumstances unable to be fully reflected in the DPP.

32. As acknowledged in the Main Policy Paper, proposing for a CPP is a costly exercise, and there is a risk that the application and determination costs may outweigh the expected benefits, which would not be in the long term interests of consumers.

33. Accordingly, the Main Policy Paper considers whether additional allowances are required to be included in the DPP price path to reduce the probability of a non-exempt ENB applying for a CPP, due to forecasting uncertainty.

2.2.1 Assessment method

34. The method adopted for determining whether an additional allowance is required comprises:[5]

a) For each ENB, calculating the difference between the DPP revenue requirement derived from the Commission's forecasts and the ENB's forecasts

b) Excluding from further consideration those non-exempt ENBs where the revenue requirement derived using the Commission's forecasts exceeds that derived from each businesses own forecasts[6]

c) Excluding from further consideration those non-exempt ENBs where the revenue requirement derived using the businesses own forecasts significantly exceeds that derived using the Commission's forecasts. This decision is made on the basis that the costs of applying for a CPP are unlikely to deter an application given the potential magnitude of the revenue uplift.

35. Although not explicitly stated, we have inferred from the discussion in Attachment B of the Main Policy Paper, that no non-exempt ENB has been granted an additional allowance, on the basis that five ENBs (Nelson Electricity, Network Tasman, Top Energy, Electricity Invercargill and Centralines) are excluded under b) above, and the remainder are excluded under c).

36. In making the assessment under c), it is assumed that the upper bound of the cost of a CPP is $2.5m. It is not clear from the Main Policy Paper, or the accompanying model[7], how this estimate was derived, or what costs it includes. In this respect we note:

a) Cell B12 in the calculations sheet of the model describes the $2.5m allowance as "all costs of a CPP incl. internal time"

b) Footnote 96 suggests that in practice the Commission expects that the costs of a CPP are likely to be much lower when made in response to DPP revenue allowances (ie: unlike a catastrophic event which may include additional costs to determine appropriate quality standards).

37. The full costs of a CPP application include the costs which are able to be passed on to consumers (application fee, Commission's assessment, verification, audit and engineering assessments) and those which are not (the ENBs internal costs and advisors costs). The former category appears to be excluded from the assessment, which we assume is on the basis that they are able to be recovered through prices. We consider that this presentation is misleading as it understates the full costs of determining a CPP (which are shared between consumers and suppliers).

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[5] The method is described in Attachment B of the Main Policy Paper

[6] We note and support the decision not to adjust the Commission's forecasts down where they exceed an ENB's own forecasts, as this is consistent with the low cost approach to determining the DPP, which applies a consistent approach to all

[7] Model 14 – Loss allowance draft EDB reset

38. We consider that the full costs of applying for a CPP are relevant to the assessment as to whether an additional allowance is included in DPP revenues.

39. We also note that the method for estimating a forecasting error allowance ignores the risks associated with applying for a CPP, and does not consider that the relevant counterfactual is influenced by CPP parameters (such as cost of capital, the end of CPP price setting method, and the likelihood that a CPP will span more than one DPP regulatory period.)

40. We note that the analysis in Main Policy Paper suggests that 11 of 16 ENBs may be sufficiently incentivised to apply for a CPP due to forecasting error, and therefore no forecasting error allowance is provided. We question this outcome, and note that the DPP/CPP framework is not designed to address a large number of CPP applications following a DPP reset, in order to address forecasting differences.

41. In order to remedy this outcome we submit that the proposed forecasting approaches require review (and our suggestions in this respect are included in our accompanying submission on the Low Cost Forecasting Paper).

2.3 Productivity-based rate of change

2.3.1 Proposed productivity-based rate of change

42. The Commission is proposing to use a productivity-based rate of change (i.e. X factor) of zero for the regulatory period. The rationale for this choice is a report from Economic Insights (EI) on the long-run average productivity improvement of ENBs in New Zealand. The ENA notes that the analysis covers the period 1996-2013. The ENA submits that the earlier data in this series is not robust and should not be included in the study or used as the basis for setting productivity in the next regulatory period. In particular, the structural break with the separation of lines and retail in 1999 causes an obvious discontinuity in the data.

43. The ENA has had its own analysis of productivity trends completed by Pacific Economics Group (PEG) which we have already provided to the Commission.[8] PEG also prepared a review of the EI report; we have provided the Commission with a copy of this analysis as well.[9]

44. Both the EI and PEG reports on productivity note that ENBs' productivity has declined over the last decade at least. The only exception to this is EI's specification #1. PEG notes that this output specification is problematic from a conceptual and empirical perspective as it uses the same factor as both an input and an output, and the acknowledged decline in demand over the last decade is not consistent with the data.

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8 Pacific Economics Group *Productivity Trends of New Zealand Electricity Distributors,* June 2014

9 Pacific Economics Group, *Review of Economic Insights' Report "Electricity Distribution Productivity Analysis: 1996-2013"*, August 2014

The ENA submits that the Commission should not give weight to specification #1 in the EI report.

45. We discuss issues identified with the EI specifications of outputs and input prices in our submission on the Low Cost Forecasting Paper. In short, it is important that the specifications adopted are consistent throughout the opex forecasting formula. These issues also apply to the total factor productivity measure used by EI to estimate the X factor.

46. The Commission should also consider the consequences of an error in the level of the X factor. If X is set too low, there is a delay in consumers benefiting from increases in productivity until the next regulatory period. If X is set too high, ENBs are unable to attain the productivity 'expected' which means they need to either inefficiently decrease expenditure, or apply for a CPP.

47. The ENA submits therefore that it is not appropriate to discount the empirical evidence without proper evidence; the Commission should be conservative in its choice of X factor.

48. There appears to be hesitancy by the Commission to using a negative productivity factor despite regulatory precedent in Australia and the UK. The ENA emphasises that declining productivity is not the same thing as declining efficiency and should not be judged as a "bad" outcome or something to be avoided. Productivity is the ratio of actual outputs to actual inputs. It has meaning in the way it changes over time. Efficiency on the other hand is a relative concept and speaks to the amount of output actually produced (from given inputs) compared to the maximum amount of output that could be produced from those inputs given the technology.

49. The PEG review of the EI report explains why negative X factors can be appropriate, if industry-wide input quantity is growing more rapidly than industry-wide output quantity *and* that trend is expected to persist. There is systematic evidence of output growing more slowly than inputs (both total inputs and opex inputs). In the last 10 years in PEG's sample for TFP and 8-9 of the last 10 years for opex PFP (depending on the output specification).

50. Negative productivity growth is not necessarily evidence of declining efficiency, productivity is simply the ratio of outputs to inputs. There are several factors that can result in declining productivity only some of which relate to efficiency.:

a) Change in management efficiency at the individual enterprise

b) Industry-wide 'technical change' which is often interpreted as exogenous changes in efficiency

c) Changes in economies of scale resulting from output growth

d) Changes in the operating environment that are independent of output

e) Changes in opex PFP that relate to changes in the capital stock

51. One of the factors that gives rise to negative productivity growth is slow output growth. The data show that between the first and second halves of the sample period used by PEG (2001-2012) output growth slowed by 0.46% in their preferred 2-output specification. PEG's view is that slowing output growth is an almost universal trend in utility industries in Western economies. They believe this trend will continue and may even slow further in coming years as policy is expected to put further downward pressure on electricity use.

52. This expectation is consistent with the report (attached to our submission) prepared by Sapere Research Group that describes the underlying causes of slow demand growth in the residential sector.[10] The view expressed in that report is that continuing improvements in the average efficiency of appliances and space and water heating is likely to drive continued declines in residential use per household over the coming regulatory period.

53. This contrasts with the view expressed by EI that "there is also some expectation from experts, including the AER and the Australian Energy Market Operator (AEMO), that positive electricity demand growth will resume, albeit at a reduced rate compared to the period before 2007."[11] Australian demand forecasts are likely to be based on quite different factors to those that are important in New Zealand not least because we have a different climate and different industry structure. Indeed the drivers identified by the AEMO are largely either absent or different here: three large LNG projects and population growth offset by increases in rooftop solar PV, energy efficiency from new building regulations and industry closures and downsizing. The AEMO's forecasts have so far proved optimistic.

54. A paper presented by the Brattle Group at the ACCC conference in August 2014 provides further evidence that the change in electricity growth is permanent.[12] While the focus of the paper was on possible strategies for ENBs faced with demand that is either growing only slowly or declining, it expounds "five forces" that have shaped and will shape the drop in growth. These are:

a) Consumer psychology has shifted – a new generation of consumers with new values and norms has pushed energy efficiency into the mainstream; some consumers faced with economic uncertainty are doing financial belt-tightening[13]

b) Utilities are spending more on energy efficiency programs often prompted by new legislation and standards

c) Governments are introducing aggressive enhancements to codes and standards

d) Distributed generation is reducing the need for grid supply

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10 Sapere Research Group, *Trends in Residential Electricity Consumption* by Dr Stephen Batstone and David Reeve, 5 August 2014.

11 EI, p.39

12 Faruqui, A *Strategies for Surviving sub-one percent growth: an American perspective*, The Brattle Group, 7 August 2014 (http://www.accc.gov.au/system/files/Session%203%20Regulating%20in%20the%20face%20of%20declining%20demand%20%20A%20Faruqui.pdf accessed 12/8/14)

13 These consumer values are confirmed in UMR research for the Electricity Authority, which shows that only 20% of consumers in the survey reported making no effort to manage use.

e) Fuel prices are declining due to the revolution in shale oil and gas leading to substitution away from electricity toward gas.

55. Most of these forces have some relevance to New Zealand

56. The New Zealand data indicates that even in the face of relatively slow demand growth there has been a rapid capital investment (practically doubling growth in capex inputs between the two halves of the study period). This investment is largely replacement of ageing assets and is expected by businesses to continue. There is no evidence that this increase in capital has resulted in a decline in opex by ENBs.

57. Factors in ENBs' operating environment that have given rise to increases in rising opex include changes to health and safety, ongoing increases in regulatory requirements, growing customer demands for quality of service such as those arising from Consumer Guarantees Act changes and greater customer awareness of quality as a result of deployment of advanced meters. These factors are independent of the level of output used to calculate productivity.

58. EI raises the advice given to the Ontario Energy Board on productivity factors by PEG as a partial justification of suggesting a zero rather than negative factor. As PEG sets out in their report, the circumstances in Ontario were somewhat different to those currently applying in New Zealand.

59. The evidence relied on by EI and the Commission in turn to disregard the empirical results that show that productivity is falling is not relevant to New Zealand. The ENA submits that the opex productivity assumption has significant impact on the allowable revenue calculation and the onus is on the Commission to establish a robust case based on relevant, quantitative evidence to override the results of both the EI and PEG reports. The ENA is concerned that the Commission is ignoring the long term trends and adopting values of zero for both the X factor and opex PFP without any substantive evidence or model to show what will change in future to stop the long-term trend. It is not appropriate to rely on an assertion by EI that zero is appropriate without any empirical support for that approach.

60. The ENA submits that the Commission should adopt a -2% per annum opex partial productivity factor, consistent with the evidence in the PEG report. The analysis of PEG should be preferred because it is consistent with the Commission's broader forecasting approach (e.g., use of all-industries LCI, and opex forecast drivers) whereas the EI analysis is not.

2.3.2 Impact on allowed revenue

61. The ENA acknowledges that the productivity-based rate of change (X factor) does not affect the amount of revenue recovered over the regulatory period, where prices are reset on the basis of current and projected profitability. It does however impact on the profile of revenue recovery over the regulatory period, and thus the level of prices at the end of the regulatory period. We note that this may also have second order affects, including:

a) The resultant price step into the next regulatory period

b) The probability and timing of making a CPP application.

2.4 Minimising price shocks

62. The Main Policy Paper indicates that, similar to the 2012 reset decision, the initial adjustment to prices has been considered to determine whether undue price shocks to consumers may occur. Alternative rates of change during the regulatory period may be used to mitigate the initial price step, where necessary, subject to achieving present value neutrality. As noted in section 2.3 above, the proposed productivity rate of change is 0%, to apply to all. Alternative rates of change are assessed incrementally to this DPP wide assumption. The ENA supports this incremental approach.

63. In making this assessment, the following factors have been considered:

a) the current DPP price path for FY15

b) one off recoverable cost allowances (which may be positive or negative) in FY15, due to claw-back provisions

c) deferral of claw-back into the next regulatory period for some ENBs

d) the revenue requirement for the next regulatory period (as set out in the financial model[14]), assuming no alternative rate of change.

64. The ENA agrees that each of these factors is relevant to the assessment of how the initial price step for the next regulatory period is set. We also consider that there are second order affects, as described in paragraph 61 above, which are relevant to determining the slope of the price path.

65. The Main Policy Paper proposes alternative rates of change for some ENBs (refer paragraph 4.24). These alternative rates of change defer the recovery of the revenue requirement until later in the regulatory period; however the total revenue requirement is able to be recovered in the five year regulatory period.

66. No alternative rates of change are proposed where the initial price step is negative, irrespective of the magnitude of the step.

67. The ENA has considered the method adopted for determining the alternative rates of change (as set out in Attachment C to the Main Policy Paper and relevant supporting models[15]) and make the following observations:

a) The price cap used to determine whether an alternative rate of change applies is 5%. The Main Policy Paper does not explain how this cap was determined. We note that 5% is significantly lower than the caps that were considered for the 2012 reset (where a cap of 15% was initially proposed, and subsequently reduced to 10% for the final decision). As distribution prices make up approximately one third of delivered electricity prices, the price change impact on consumers is much less than 5%

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[14] Model 9 – Financial Model draft EDB reset

[15] Model 10 – price changes draft EDB reset; Model 11 – revenue changes draft EDB reset; Model 15 – Claw back draft EDB reset

b) The impact of specifying large rates of change is that prices at the end of the regulatory period are substantially higher than at the beginning, and thus substantially higher than the underlying building blocks allowable revenue. This may result in a significant price step correction at the next regulatory period which we consider should be mitigated if possible. One way of doing this is to increase the cap at the beginning of the regulatory period.

68. We consider that where an alternative X factor is proposed, input from the relevant ENB should be considered before a final decision is made. This will allow particular customer and network demands to be considered before final price paths are determined.

2.5 Recommendations

69. For the purpose of specifying price limits for the 2015 DPP reset the ENA:

a) Supports resetting price paths on the basis of current and projected profitability.

b) Acknowledges the plan to introduce incremental improvements to previous forecasting methods. However we submit that it is necessary to test previous forecasts against outturns before finalising the forecasting models and we encourage the Commission to consider our accompanying submission on Low Cost Forecasting Approaches in this respect.

c) Notes that it is important that price limits are set with sufficient consideration of the obligations which must be met by ENBs in delivering electricity lines services, while ensuring the health and safety of staff, contractors and the public.

d) Notes that ENBs in general have been unable to achieve target returns in the current regulatory period. While some ENBs choose to price below their price paths, higher than forecast opex, lower than forecast CPI, and lower than forecast volumes are some of the other reasons which have contributed to the lower returns than predicted. The ENA considers that this context is relevant to determining the forecasting methods for the next regulatory period, and in particular, demonstrates that the Commission's forecast models have not delivered prices that have enabled ENBs to cover their costs.

e) Supports the inclusion of allowances for forecasting uncertainty in DPP price paths and notes that the Commission's analysis suggests 11 of 16 ENBs may be sufficiently incentivised to apply for a CPP due to forecasting error. The ENA considers this outcome is not consistent with the design of the DPP/CPP regulatory framework and submits that forecasting methods must be improved (and our suggestions are included in our accompanying Low Cost Forecasting Submission).

f) Considers that in respect of the productivity-based rate of change the Commission should set the X factor and associated opex PFP at negative values as indicated in the PEG report (and supported by the empirical evidence in the EI report prepared for the Commission). A conservative value is appropriate on the balance of risks between ENBs and consumers and there is no relevant quantitative evidence that suggests a higher value (such as zero) is warranted in the New Zealand context. While the ENA recognises that the Commission is entitled to exercise judgement in making its decisions, given that there is strong and consistent evidence of a long-term decline in measured opex PFP and TFP from two independent experts, the Commission must provide a robust empirical base of research and evidence to depart from this expert view. To do otherwise leads to a perception that the Commission has predetermined the outcomes to lead to lower consumer prices, behind the façade of an independent empirical process.

g) The ENA submits that the Commission should adopt a -2% per annum opex partial productivity factor, consistent with the evidence in the PEG report. The analysis of PEG should be preferred because it is consistent with the Commission's broader forecasting approach (e.g., use of all-industries LCI, and opex forecast drivers) whereas the EI analysis is not.

h) Supports the use of alternative rates of change to mitigate initial price steps, however considers that the proposed method assumes an initial price step which is too low and which does not adequately consider the gap between the price path and underlying building blocks which emerges at the end of the regulatory period, when large alternative rates of change are adopted.

i) Suggests ENBs which are facing alternative rates of change are consulted about their preferred price path profile before final price paths are determined.

3. Allowances for pass through and recoverable costs

3.1 Recovery of pass through and recoverable costs

70. The purpose of pass through and recoverable costs (which sit outside the DPP weighted average price cap), is to allow distributors the opportunity to recover in full costs which are largely outside their control.

71. The ENA supports the pass through and recoverable cost mechanisms because they reflect charges which are passed on to distributors for services which are associated with, but not directly undertaken by the distributor in delivering electricity (for example electricity transmission, industry regulation and local government services). Accordingly, distributors have no ability to control the costs of those services and very little ability to influence them, and thus should not be financially exposed to changes in these costs over time.

72. We note that other disciplines exist, outside of the DPP, which influence the level of charges which ENBs incur in this respect (eg: Transpower is subject to Part 4 regulation which limits its total revenue requirement, and the Electricity Industry Code determines how Transpower's revenue requirement is shared amongst its customers, including distributors).

3.1.1 Ability to recover pass-through and recoverable costs

73. As acknowledged in the Main Policy Paper, it has not always been possible for distributors to recover these costs in full, and in some instances inadvertent over recovery has led to breaches of the price path, and costly investigation processes and administrative settlements with the Commission. The key reasons for this include:

a) Difficulty in forecasting the required amounts

b) The volume risk which is inherent in the price path formula, which also applies to these costs.

74. For this reason, in our submission on the Process and Issues Paper we proposed options for mitigating compliance and volume risk in general and also specifically as they apply to pass through and recoverable costs.

75. We note that on 18 July, additional consultation papers were released which include proposals for amendments to the provisions for the recovery of pass-through and recoverable costs. These papers also address other compliance concerns and IM amendments associated with the DPP.[16]

76. Our submissions on those papers, which are due on 29 August, will include our detailed comments on the proposals to:

   a) Adopt a form of revenue control for the recovery of transmission charges (excluding the recoverable cost incentive for the transfer of spur assets)

   b) Apply an ascertainable cost method for other recoverable costs and all pass-through costs, similar to that implemented for gas pipeline services.

77. In this respect we note that it is important that ENBs are able to recover these costs in full on a timely basis, including if necessary, recovering costs incurred in one regulatory period, in the following regulatory period. We are concerned that some of the proposals in practice result in a deferral of legitimate costs, in perpetuity and possible non-recovery in the event of a catastrophe.

3.2 New recoverable cost

78. The 2012 price caps for some non-exempt ENBs resulted in under recovery of allowable revenue in the current regulatory period. Accordingly a new recoverable cost is proposed for the forthcoming regulatory period, to allow the shortfall to be recovered.

79. The ENA supports this proposal in principle and will consider the specific proposal in detail in responding to the associated IM amendment papers by 29 August.

3.3 Recommendations

80. For the purpose of specifying pass through and recoverable cost allowances the ENA:

   a) Supports proposals to amend the DPP to allow ENBs to recover pass through and recoverable costs in full.

   b) Supports proposals to introduce a new recoverable cost to allow the recovery of the shortfall in revenue which applies to some ENBs as a result of price caps applied in the current regulatory period.

   c) Notes that it is important that ENBs are able to recover these costs in full on a timely basis, including if necessary, recovering costs incurred in one regulatory period, in the following regulatory period.

[16] Commerce Commission, Proposed compliance requirements for the 2015-2020 default price-quality paths for electricity distributors, 18 July 2014; Proposed Amendments to Input Methodologies for Electricity Distribution Services, 18 July 2014; and Proposed electricity distribution input methodology amendments 2014 (second type), 18 July 2014

4. Targets and incentives for service quality

4.1 Revenue linked quality incentive scheme

81. The ENA, with the assistance of the Quality of Supply Work Group, has considered a number of options for how quality standards maybe determined for the 2015 DPP. In our submission on the Process and Issues Paper, we submitted that, for the purpose of determining quality standards for the next DPP regulatory period:

a) Reliability measures are retained as the primary measure of service quality for the forthcoming DPP reset, and any potential additional measures are introduced firstly via ID regulation before further consideration for DPP purposes in the longer term

b) Moving to a more incentive based approach to determining the DPP quality standard, that any changes that are introduced are rigorously stress tested prior to implementation, and that an incremental approach is adopted for the forthcoming reset

c) A number of further refinements to the current reliability measures should be investigated to improve the treatment of extreme events and normal variation and the interplay between the measures

d) Further analysis of reliability data is required, before the parameters for an incentive scheme are determined

e) An incentive scheme would require some form of an adjustment factor to be included in the DPP price path.

4.1.1 Incentive scheme proposed

82. The Main Policy Paper proposes a revenue linked quality incentive scheme. The key features of this scheme include:

a) Two reliability targets, reflecting annual (Class B and Class C) SAIDI and SAIFI performance

b) A ten year reference period, from 1 April 2004 to 31 March 2014

c) 50% de-weighting of planned outages

d) Normalisation of extreme events using a modified IEEE 2.5 beta method. Modifications include:

i. Boundary values adjusted to reflect zero event days

ii. A SAIDI major event day is dependent on SAIFI exceeding boundary on the same day

iii. Major event days normalised to the boundary *e)* Targets are adjusted downwards proportionately for prior breaches

f) Caps and collars for the incentive scheme set as one standard deviation around the target

g) Revenue at risk is 1% of maximum allowable revenue (in the first year of the DPP), shared equally between SAIDI and SAIFI

h) Performance above the target is deemed non-compliant:

i. No enforcement action is envisaged where performance is under the cap, except in exceptional circumstances

ii. Pecuniary penalties may be sought in addition to financial penalties which arise from the incentive scheme.

83. The QoS Companion Paper[17] released on 18 July includes a detailed description of the proposed scheme. ENA members are currently considering the information available about the proposed scheme and the ENA will respond in a submission on the Companion Paper by 29 August.

4.1.2 Success criteria

84. As previously submitted, the ENA supports a move to a quality incentive scheme, however determining the key features of the scheme are critical to its success. We note that there are many different options available given the multiple steps that are involved in specifying quality targets and associated revenue incentives.

85. We consider that the following criteria are useful in considering alternative options, and we are currently assessing the proposal against these criteria.

Feature of Quality Incentive Scheme	Relevant Success Criteria
Measuring quality	Customer value Ability to implement
Reference period	Currency Inter period variation Certainty
Treatment of planned outages	Customer preferences Restoration incentives Incentives to undertake planned work
Identifying extreme events	Measuring underlying reliability performance Equitable treatment across ENBs

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

Feature of Quality Incentive Scheme	Relevant Success Criteria
Normalising for extreme events	Measuring underlying reliability performance Restoration incentives Incentives to undertake remedial work
Accommodating normal variation	Avoiding false positives Maintaining no material deterioration standard Inter period/annual variation
Revenue at risk	Strength of incentive Risk and reward
Caps and collars	Symmetry Strength of incentive Risk and reward Consistency across ENBs Cost/value of incremental quality
Incentive mechanism	Complexity Lag before reward/penalty applies Volatility
Compliance and enforcement	Certainty Incentives and risk Avoiding false positives Extreme circumstances

86. We also consider that the quality incentive scheme must demonstrate materially better outcomes than the status quo, ie: retaining the pass/fail approach to determining quality standards. In this respect we are currently assessing the proposal with reference to the current quality standards.

87. While there are many of the features of the proposed scheme which we consider are consistent with the success criteria noted above, there are some features we are particularly concerned about, including:

a) Normalisation for major events – we do not consider that the proposed approach achieves reasonable outcomes because the frequency and magnitude of major events will primarily determine whether a business complies with the quality standard, and whether the cap or collar is reached in any year. The proposed approach to normalisation is contrary to international methods. It is our preliminary view that this is not suitable for a revenue incentive scheme. As a consequence the financial penalties and rewards will be unduly influenced by the weather and other drivers of significant unplanned events.

b) Compliance and enforcement – the proposal for the target to be set as the non-compliance threshold is not supported. This means that on average half of the ENBs can be expected to be non-compliant every year due to normal variation around the historical average. This situation existed under the thresholds regime and was corrected when the DPP quality standards were first introduced. We consider that this approach significantly increases regulatory uncertainty for businesses, and generates unreasonable compliance outcomes.

c) Adjustments for prior year breaches – the proposed pro-rata adjustments for those which have breached their DPP quality standards are internally inconsistent because they have been applied to normalised datasets which have different characteristics to the normalised datasets used to determine the breaches.

88. Our preliminary view is that, given the issues noted above, the proposals result in a scheme that would be worse than the current approach, because it is asymmetric. ENBs will be doubly penalised for exceeding their average long-term reliability performance because in addition to paying out to consumers for above target outcomes, they may also face investigations of performance.

89. The proposed scheme is heavily influenced by the frequency of major event days. In years where there are above average numbers of storms, not only will EDBs have to pay the additional costs of remediation, but pay their customers for the impact of the poor weather on their network performance. The ENA considers that a scheme which is unduly influenced by the weather does not meet the underlying objective of recognising/penalising systematic improvements/declines in performance.

90. We consider that these issues must be addressed before a revenue incentive scheme can be introduced successfully. Our detailed submission on these and other aspects of the proposed quality standards will be included in our forthcoming submission on the Quality Standards Paper.

91. We note that we are in principle supportive of a revenue linked incentive scheme provided it operates in a credible and reasonable way. In our forthcoming submission we will outline the changes that we consider must be made to the proposed incentive scheme before it can be introduced. Absent these changes, retention of the current pass/fail model is the appropriate alternative.

4.2 Recommendations

92. With regards to the service quality component of the DPP:

a) The ENA in principle supports a move to a quality incentive scheme; however we note that determining the key features of the scheme are critical to its success.

b) The current proposal is currently being considered by our members and will be responded to in our forthcoming submission on the QoS Companion Paper.

c) We have developed success criteria to better evaluate the range of options available (including the option of retaining a pass fail quality standard) and encourage the Commission to consider these criteria before finalising the DPP quality standard.

d) We have particular concerns with the proposed approach to normalisation, compliance and enforcement, and the pro rata adjustments for prior period breaches.

e) The proposed scheme is heavily influenced by the frequency of major event days. The ENA considers that a scheme which is unduly influenced by the weather does not meet the underlying objective of recognising/penalising systematic improvements/declines in performance.

f) We consider that these must be addressed before a revenue incentive scheme can be introduced successfully. Absent these changes, retention of the current pass/fail model is the appropriate alternative.

5. Other incentive mechanisms

5.1 Energy efficiency, demand side management and the reduction of losses

93. The ENA has previously undertaken significant work on how to improve incentives to undertake energy efficiency initiatives.[18] We are pleased to note that the Commission has given this work some prominence in its consideration of these incentives. Our comments in this section draw from that report, and our earlier submissions on the Process and Issues Paper and the Incentives Paper.[19]

94. The EEI Working Group paper developed a set of principles to drive the consideration of changes to ENBs' incentives.[20] The ENA submits that ultimately incentive mechanisms should provide:

(a) Equal incentives among alternative options that deliver the same outcomes (ie: equal treatment of efficiency opportunities with traditional network solutions)

(b) Equal incentives to invest in opex or capex such that one is not favoured over the other.

(c) Stable incentives over time for opex and capex

(d) Incentives aligned with consumers such that:

(i) ENBs are able to share in wider industry benefits (including cost savings) from their opex and capex

(ii) ENBs have certainty that they will be able to recover all expenditure that is in consumers' long-term interests, even if it relates to non-traditional assets

(iii) ENBs pursue the least cost option.

95. In principle, the ENA supports the proposals in paragraph 7.7:

a) Introducing a D-factor to provide compensation for revenue foregone as a result of some energy efficiency and demand-side management initiatives

b) Removing the penalty for investing in short life assets instead of longer life assets

c) Providing guidance on the definition of "electricity lines services"

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18 ENA Energy Efficiency Incentives Working Group *Options and Incentives for Electricity Distribution Businesses to Improve Supply and Demand-Side Efficiency,* 31 March 2014

19 Commerce Commission *Default Price-quality Paths from 1 April 2015 for 17 Electricity Distributors: Process and Issues Paper,* 30 April 2014; and Commerce Commission, *Incentives for Suppliers to Control Expenditure During a Regulatory period: Process and Issues Paper,* 20 September 2013

20 See p.43

d) Minimising the impacts of price restructuring on DPP compliance.

96. However we have some comments on the timing and manner of their implementation.

97. Likewise we agree in principle with the commentary around the need to consider how to make the incentives to invest in capital expenditure (capex) or operating expenditure (opex) more equal. However we have some concerns about introducing a capex incentives mechanism in the manner proposed at this time, given the method for forecasting capex. We discuss these concerns below in the section on incentives to control expenditure.

5.1.1 D-factor

98. The Main Policy Paper states:

> *Under the proposed approach [introducing a D-factor] distributors would only be compensated for foregone revenue resulting from energy efficiency and demand side management initiatives, i.e. excluding compliance costs. We therefore do not propose to compensate for additional operating or capital costs associated with the demand side management activities.*[21]

99. The proposed D-factor reduces the disincentive not to pursue efficiency initiatives. The ENA supports such a mechanism in principle.

100. However, the ENA submits that:

(a) The Commission should regard efficiency initiatives as electricity lines services where they serve this end purpose. This would ensure that opex and capex associated with implementing these initiatives are able to be recovered.[22].

(b) There may be significant compliance costs associated with applying to the Commission for the recovery of revenue foregone as a result of reduced volumes. In particular, the requirements in the principles (Table E1) relating to estimating the reduction in demand due to the initiative are relatively onerous, for example requiring the estimation of the impact of other factors that may affect demand. The Commission recognises this fact noting that there is a trade-off between providing sufficient verification of the link between energy efficiency and foregone revenue, and compliance costs. The Commission also notes that ENBs are free to withdraw their application for revenue recovery where the compliance costs become too high. The Commission should ensure these costs are minimised so as not to provide a disincentive to engage in efficiency initiatives.

(c) The2 year lag proposed between the implementation of the initiative and the adjustment for volume reductions may be a disincentive to undertake efficiency initiatives. While the ENA supports the Commission using existing compliance approaches to implement new initiatives in order to preserve the present value of the recoverable cost a time value of money factor should be applied.

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21 *Main Policy Paper ,* paragraph E8

22 See section 5.1.3.

(d) There is no certainty that the ENB will be able to recover some or all of the foregone revenue through the D-factor, as the Commission will ultimately determine the amount to be recovered. This is a disincentive to undertake efficiency initiatives and the Commission should ensure it minimises this by using clear, consistent decision frameworks.

101. Furthermore, the Commission has decided that efficiency initiatives related to changes to price structures are not eligible for the energy efficiency recoverable cost (at least initially). The rationale for the distinction between types of efficiency initiatives is not described, and the ENA does not consider this distinction is necessary and indeed is likely to create a substantial barrier to ENBs that are considering structural changes, but are concerned about their ability to manage revenue risks associated with customer behaviour changes.

102. These factors should be addressed to the extent practicable to ensure efficiency initiatives are pursued where possible.

103. In our submission on the Process and Issues Paper we noted that another way to address this disincentive (as well as other volume risks) would be to provide for an adjustment factor to take into account all volume variances between the DPP forecasts and actuals beyond a certain threshold. Such a wash-up would better meet the principles we advocate above. In short, a wash-up would be simpler, less costly for both the Commission and ENBs, provide certainty over the outcome (over time and for different types of initiatives) and ensure that the consumer shared the benefits. We described how such an annual ex-post adjustment mechanism could work in that submission and we repeat that explanation here:[23]

   a) The net revenue impact (up or down) from the period is measured and reported. This measurement and reporting could be specified as part of the information disclosure requirements.

   b) The net revenue impact could be introduced into the adjusted year by way of an "adjustment factor" that would sit within the DPP compliance formula in the same way as is currently the case for recoverable and pass through costs. Thus this adjustment factor, expressed as a dollar value, would enable the ENB to adjust its prices upward, or require it to lower its prices, to address the revenue impact.

   c) In practice there would need to be a lag between the period that is measure and the period in which the adjustment is made, due to the timing of disclosures. In order to maintain the present value of the adjustment amounts, a time value of money factor would need to be applied.

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23 ENA *Submission on default price-quality paths from 1 April 2015 for 17 electricity distributors: process and issues* paper, 30 April 2014, see sections 5.2.1 and 4.5.

5.1.2 Neutralising the incentive to invest in long-lived assets

104. The Commission's intention is to introduce a wash-up for the difference between forecast return on and of capital during the regulatory period and actual return during the period. This wash-up would be applied as a recoverable cost (part of the capex incentive adjustment) in year 2 of the next regulatory period.

105. The ENA supports this initiative and notes that it should not be considered dependent on the introduction of a capex incentive adjustment. This wash-up will address the incentive to invest in long-lived assets created by the assumption that assets have an average lifetime of 45 years.

5.1.3 Providing guidance on the definition of "electricity lines services"

106. Electricity lines services are defined in s54C. In its working paper on energy efficiency, the ENA's EEI working group noted that a narrow interpretation of electricity lines services could limit the scope of activity to which s54Q applies to that which occurs before the customer's point of supply (which could be the meter or the boundary). This potentially constrains the set of attractive efficiency investments to more conventional assets.

107. The ENA submits that efficiency investments should be regarded as electricity lines where they serve this end purpose. As efficiency measures may involve investments beyond the consumer's meter, clarification of the interpretation of electricity lines services or the circumstances where narrow definitions are not applicable would be useful. The ENA welcomes the Commission's intention to provide guidance on specific examples, but submits that ENBs should be free to take up technological change and innovate, which suggests a less case-specific approach would be valuable.

108. In addition to clarifying the scope of investments that are included, there is a need to clarify the treatment of costs and revenues relating to efficiency investments. For efficiency investments that are higher cost than traditional solutions, but where there are wider benefits, the ENA submits that the ENB should be able to contract with other parties that benefit for the difference in cost. To ensure that ENBs have appropriate incentives for higher cost efficiency options, cost allocation rules in the input methodologies need to allocate the portion of the cost of the efficiency option up to the value of the traditional alternative as relating to regulated activity and therefore included in the RAB and price path. Additional revenue should be treated as unregulated revenue: this ensures that the ENB pursues the lowest cost option but has incentives to invest in higher cost alternatives where there are benefits to other parties that are willing to fund the difference. Costs should be treated in the same manner irrespective of whether the ENB itself or a third party delivers the efficiency initiative.

5.2 Incentives to control expenditure

109. The ENA supports the intention of the incentive mechanisms to make the incentives time consistent. However, we submit that it is not appropriate at this time to implement material rewards or penalties for variations in expenditure because the methods for forecasting opex and capex are not sufficiently robust to support applying incentive pressures to variations to those forecasts. It is better to set a lower incentive if the key driver of "efficiency/inefficiency" is in fact likely to be forecasting error. Our accompanying submission on the Low Cost Forecasting Paper highlights our particular concerns with the proposed approach to forecasting capex and opex for the forthcoming regulatory period.

110. The opex incentive mechanism aligns the incentive in later years with the level that applies in year 1. The ENA supports an approach that equalises the incentives in all years of the regulatory period in principle and will comment further on its implementation in its submissions on the IRIS papers.[24]'

111. The capex caps ensure that the capex forecast is set to a low value, and as such an incentive mechanism that limits the ability of ENBs to recover costs between the cap and their own capex forecasts from their AMP imposes a penalty associated with forecast errors that result from the Commission's low cost approach. .More work is required first to develop a capex forecast that is credible and sustainable.

112. In contrast, in the national electricity market in Australia, the regulator is establishing a range of incentive schemes including the EBSS targeting at improving operation expenditure and more recently the Capital Expenditure Sharing Scheme (CESS). However, network service providers are required to submit detailed proposals for operating and capital expenditure requirements. The expenditure forecasts are forward looking and are aimed at meeting technical service requirements. The regulator is required to assess these proposals against a set of objectives and criteria in the national electricity rules. The assessments involve external technical experts to review the proposals by the network service provider. The AER can either accept the proposals or reject them and substitute its own expenditure forecasts. Such an approach is clearly more costly than the DPP.

113. However, under the approach in Australia, the costs are likely to better reflect the efficient cost requirements of each of the network service providers. Thereby an incentive scheme will place even greater pressure to achieve more efficiency. This contrasts with the Commission's approach whereby forecasting error is likely to play a role in any differences in expenditure.

114. Given this context, the ENA submits that the capex incentive mechanism retention factor should be set to 5% within a band between the cap and the ENB's AMP forecast. Outside this band, the retention factor should be set to 10%. These limited penalties and incentives recognise that the Commission's forecasting approach remains relatively unsettled and somewhat arbitrary and that variations from the forecast have a number of explanations.

115. There are important distinctions between opex and capex that need to be taken into account in designing the incentive mechanisms:

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24 Commerce Commission, *Proposed amendments to input methodologies: Incremental Rolling Incentive Scheme* and *Draft Incremental Rolling Incentive Scheme Input Methodology Amendments 2014*, both 18 July 2014

a) The level of opex tends to be more similar year-on-year compared to the "lumpy" nature of capex. This has implications for the timing of capex.

b) Capex over time defines the shape and nature of the electricity network, and once made these costs are largely sunk and need to be recovered over an extended period. Opex is more readily changed in the short and medium term. From the perspective of consumers, the most important issue is the alignment of capex investment decisions with the most efficient form of technology to provide the service demanded, rather than the precise timing of capex. Incentive arrangements for capex should therefore focus on the dynamic efficiency issues of sound capex decision-making over short-term allocative efficiency issues that arise from timing.

116. For these reasons, the ENA supports a mechanism that is neutral on the timing of capex within the regulatory period, that is where differences between the actual and the forecast relate to timing only, there is no reward or penalty incurred.

5.3 Other issues related to 54Q

117. The Main Policy Paper raises a number of other topics relevant to section 54Q, as follows:

a) Pricing structures: we will comment on the Commission's approach to price restructuring compliance issues in response to the Compliance Paper.[25] We note though that we are not aware of a rationale in principle why price restructuring should be treated differently from other energy efficiency initiatives with respect to recovery of foregone revenue (see section 5.1.1).

b) Low fixed charge: cost reflective pricing is an important prerequisite for efficient demand. In practice, the LFC regulations may make consumption charges the default for price structure thereby limiting ENBs' ability to create behavioural change through price structure. The ENA's view is that the Commission should do more than simply supply information to stakeholders, given its legislative role in creating incentives for energy efficiency and demand side management.

c) Distributed generation: we will comment on the input methodologies in relation to ACOT payments in our response to the Compliance and IM Papers. However, the ENA notes that the Commission needs to recognise that distributed generation can impose costs on electricity networks and that these should also be accounted for in regulatory decisions.

d) Losses: the ENA agrees that the extent of potential gains from reducing losses appear limited and no further action is warranted at this stage.

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25 Commerce Commission, *Proposed Compliance Requirements for the 2015-2020 Default Price-Quality Paths for Electricity Distributors, Draft Reasons Paper*, 18 July 2014.

5.4 Recommendations

118. The ENA submits for other (non-quality of supply) incentives in the DPP:

a) The Commission's proposed D-factor minimises compliance costs; includes a time value of money adjustment for the lag between the revenue foregone and the recoverable cost adjustment; minimises uncertainty over eligibility through clear, consistent decisions and frameworks. Alternatively a volume wash-up as proposed in our response to the Process and Issues Paper could be implemented. This would adjust for all volume variations between the DPP forecast and actual outturn beyond a certain threshold. The adjustment factor could be treated as a recoverable cost.

b) A wash-up of depreciation and the return on capital in the following regulatory period is introduced.

c) While the Commission's intention to provide guidance on specific examples of the definition of "electricity lines services" is welcome, a less case-specific approach to clarifying the scope of investments that are included in "electricity lines services" should be pursued. This would enable ENBs to take up technological change and innovate.

d) In principle, the ENA supports equalising incentives relating to opex and capex over time, but:

i. We will comment further on the specifics of the opex incentive mechanism in our submissions on the IRIS papers.

ii. The capex incentive mechanism retention factor should be set to 5% within a band between the cap and the ENB's AMP forecast. Outside this band, the retention factor should be set to 10%. The mechanism should be neutral on the precise timing of capex investment.

6. Reconsideration of path following catastrophic event

6.1 Amendment to input methodologies

6.1.1 Catastrophic event reopeners

119. The ENA supports the introduction of a new re-opener for the DPP, to allow a DPP to be re-considered following a catastrophic event. We note that this amendment has been directed by the High Court following merits appeals of the IMs.

120. We have previously submitted that when re-opening a DPP in response to a catastrophic event, both the price path and quality standards should be able to be reconsidered. The Main Policy Paper includes proposals as to how price paths will be re-opened, but not the quality standards.

121. We acknowledge footnote 73 in this respect, which indicates that the Commission supports reconsidering quality standards under these circumstances, and expects that this feature will be included in the DPP to the extent necessary to mitigate the impact of the catastrophic event.[26] We understand that further direction from the High Court is being sought in this respect.

6.1.2 Recoverable cost term

122. We support the proposal to include a recoverable cost term to address the financial consequences of a catastrophic event, between the time the price path is reset and the event itself. Our detailed comments on this proposal will be provided in our forthcoming submission on the DPP IM amendments.

123. We also suggest that this proposed recoverable cost should be extended to allow for financial remedies for other re-opener events, to address the consequences of the re-opener event, for the period between the event and the new price path taking effect.

6.1.3 Incentive schemes

124. We also note that a number of the proposed refinements to the DPP involve the introduction of financial incentives (rewards and penalties) for certain outcomes, including quality performance, controlling expenditure and energy efficiency and demand side management initiatives. It is expected that following a catastrophic event, actual performance is likely to be disrupted, resulting in financial penalties for the supplier in most instances.

[26] Given the Commission's intent to expand the reopener provisions to incorporate quality standards, we have not at this stage attempted to draft relevant provisions for the IMs or the DPP Determination. We are happy to contribute to the necessary drafting at the time this additional provision is included in the DPP.

125. Accordingly we submit that in addition to the proposed catastrophic recoverable cost:

a) provisions for suspension of incentive arrangements following catastrophic events should be included, on application from the supplier

b) in determining the value of the catastrophic recoverable cost, consideration should be made of the financial impact of the quality, expenditure and energy efficiency and demand side management incentive schemes on consumers and suppliers. We note that, when combined, these mechanisms have the potential to double count or understate the true financial impact of a catastrophic event on consumers and suppliers, without some form of reconciliation between them. This could also apply for other (non-catastrophic event) re-openers.

126. Our forthcoming submissions on the Draft DPP Determination and associated IM amendments will consider how these proposals can be implemented in practice.

6.2 Allocation of risk

127. The Main Policy Paper includes a discussion of the proposed approach to risk sharing between distributors and consumers. The ENA agrees that, after a catastrophic event, suppliers should be compensated for:

a) Prudent additional net costs incurred prior to resetting the DPP price path

b) Prudent additional net costs forecast to be incurred after the reset, to the end of the current regulatory period

c) Demand effects expected over the remainder of the DPP regulatory period.

128. Contrary to the proposal, the ENA also considers that demand effects that occur between the date of the event and the price path reset must also be considered.

129. The ENA submits that a specific cashflow allowance must be provided to compensate EDBs for the expected value of demand reductions following a catastrophic event. While investors can diversify their portfolios to spread risk, investments must be expected NPV≥0 in order for investment to proceed. Given the proposal that lower demand levels following an event must be borne by investors and the WACC does not include allowance for asymmetric risks, there must be *ex ante* compensation for such risks in cash flows.

130. As previously submitted, we consider that the regulatory response to a catastrophic event should consider all of the risks faced by suppliers, including demand risk, prior to a price path reset.

131. We continue to be concerned that the proposals prematurely preclude consideration of one of the possible consequences of a catastrophic event. We do not consider that it is consistent with the IM reopener provisions to rule out from re-consideration, variables relevant to the DPP price or quality path.

6.2.1 Catastrophic risk

132. Previous submissions[27] have stated that absent ex ante compensation for catastrophic risk in prices, ex post compensation is required to ensure the purpose of Part 4 is met.

133. In the Process and Issues Paper it was suggested that the "practical effect" of using a percentile uplift to the cost of capital is to provide a buffer for catastrophic events. The ENA considers that this is not a valid justification for not providing fair compensation to suppliers (either ex ante in price paths, or ex post via reopeners) as the cost of capital has been determined on a basis which explicitly excludes allowances for asymmetric (including catastrophic) risk.

6.3 Recommendations

134. The ENA recommends that following a catastrophic event:

a) DPP price paths and quality standards are able to be reopened.

b) A recoverable cost term is included to provide for the financial impact between the event and the reset price path coming into effect.

c) Further consideration is required as to the possible impact of a catastrophic event on the proposed quality, energy efficiency and demand side management and expenditure financial incentive schemes. Suppliers should be able to elect to suspend these schemes following a catastrophic event, and any additional expenditure allowances must consider the net impact on suppliers and consumers after incentive rewards/penalties have been taken into account.

d) The regulatory response to a catastrophic event should consider all of the risks faced by suppliers, including demand risk, prior to and following a reset.

e) The purpose of the percentile uplift to the cost of capital is not, as suggested in the Process and Issues Paper, to provide compensation for catastrophic event risk and the ENA submits that the a specific cashflow allowance must be provided to compensate EDBs for the expected value of demand reductions following a catastrophic event. Given the proposal that lower demand levels following an event must be borne by investors and the WACC does not include allowance for asymmetric risks, there must be *ex ante* compensation for such risks in cash flows.

135. The ENA also considers that the recoverable cost term should also address the impact of other (non catastrophic) re-opener events.

[27] For example ENA, Comment on the Draft Decision on Orion's CPP Application and Implications for the Future Implementation of Part 4, 18 September 2013

7. Treatment of assets purchased from Transpower

7.1 Recoverable cost incentive

136. When developing the IMs, it was considered that it was likely to be in the long term interests of consumers to ensure that ENBs were incentivised to acquire assets from Transpower. Consumers were expected to benefit from lower delivered electricity prices as a result.

137. The IMs include an incentive mechanism (a recoverable cost) whereby ENBs are able to continue to pass through the avoided Transpower charges associated with the assets for a period of five years, for the purpose of the DPP price path. This is explained in paragraph J2.27 of the 2010 IM Reasons Paper which states: "…*assets would be added to the RAB from the date of purchase, and the supplier would be able to recover the capital and operating costs from the date of the first reset following purchase*".

138. Attachment D of the Main Policy Paper describes the proposed approach for setting the price path and quality standards for the next DPP regulatory period, where ENBs have or are planning to acquire assets from Transpower. Attachment D also explains how the incentive is to work in practice.

7.1.1 Strength of incentive

139. The current recoverable cost mechanism introduces unequal incentives within a regulatory period, as the strength of the incentive differs depending on the year of the purchase. We acknowledge the intent to consider this issue further at the next IM review, and agree that it is not necessary to address it at this time; particularly given the impact on the forthcoming reset is not expected to be material.

7.1.2 Calculating the recoverable cost

140. The Main Policy Paper proposes a new process for calculating the recoverable cost allowance following an asset transfer. This is to comprise:

a) Transpower calculating a counterfactual by running its pricing analysis assuming the assets are not transferred

b) The difference between the counterfactual and factual (ie: with the assets transferred) determines the recoverable costs for year one

c) In years two to five, the year one allowance is rolled forward at CPI.

141. We note that a new ex ante approval process is proposed for this recoverable cost. We will respond to this proposal in detail our forthcoming submission on the DPP Compliance Paper.

142. ENA members are concerned that the proposed new approach will inadvertently exclude legitimate avoided transmission costs, and be impractical to achieve in practice.

The current approach achieves reasonable outcomes and we consider it should be retained. We will be responding in more detail in later submissions however we note:

a) The proposed approach will not capture avoided interconnection charges, as these rely on lagged historical RCPD data which will not be available in Year 1

b) The assumption to restrict movements in the recoverable costs in Years 2-5 is inconsistent with the intent of the avoided transmission recoverable cost which is to provide an incentive equivalent to the avoided Transpower changes. Connection contracts will have known contract recovery profiles, which can be used. In addition the interconnection rate is not expected to move in line with inflation, and therefore should be used in this respect.

c) Some businesses have already transacted and are therefore past year 1 of their 5 year incentive period. The current arrangements should be preserved for transactions which have already occurred, to preserve the expectations under which the transaction was made.

d) The proposal is particularly complex for transactions which occur part way through a pricing year

e) The proposed ex ante approval approach introduces potential delays which could introduce unacceptable pricing variability.

7.2 Purchases prior to regulatory period

7.2.1 Asset value, capex and opex allowances

143. The ENA considers that the costs of owning and operating assets which are transferred prior to the beginning of the regulatory period should be reflected in the price path. This includes the value of the regulatory asset base, and accordingly we support the proposal to include forecast information for purchases undertaken in the final year of the current regulatory period, where the information is not known with certainty when the price path is set.

144. We recognise the desire to adjust the price path if asset transfers in the last year prior to the DPP reset do not proceed as assumed. We will comment on the specific mechanisms in our response to the IM amendments in our forthcoming submission.

145. We also support the proposal to include in the forecast period, forecast capex which is associated with the assets transferred prior to the regulatory period. We are concerned however at the proposal to make this conditional on those forecasts aligning with Transpower's plans. There may be valid reasons why they differ including:

a) The ENB has a different range of options available once the assets are integrated into the network

b) Transpower may have not fully developed its capex plans, pending the transfer

c) The ENBs cost structures may differ *d)* The timing may differ due to other commitments of Transpower and/or the ENB.

146. It is these differences which create the incentives to invest in the assets, and therefore the conditional approval of capex (ie: that it aligns with Transpower's) is contrary to the intent of the incentive.

147. It is not proposed to include additional opex forecasts for assets transferred in the regulatory period. Instead it is proposed that the current opex forecasting method will apply. This method uses a base year opex and projects it forward after adjusting for scale effects and input price inflation. The scale effects are calculated by extrapolating the historical rate of change in connections and circuit kms.

148. We note that, the magnitude of any additional opex allowance associated with assets transferred from Transpower will depend on:

a) Whether the assets were transferred prior to the base year in the current regulatory period

b) The level of opex in the base year associated with the assets

c) Whether the transfer of assets had any impact on the connections and circuit km data used to derive the scale adjustments.

149. We consider that this approach is likely to be a poor predictor of the opex impact of assets transferred prior to the regulatory period because:

a) it is highly dependent on the circumstances that applied in the base year (and thus some asset transfers will miss out on any opex allowance)

b) transmission assets are unlikely to have associated customer connections and may also add little by way of circuit length

c) the customer connection and circuit length adjustments provide no additional allowance for costs of operating new substation assets.

150. Accordingly the ENA does not support the proposal, and considers that forecasts of additional opex should be established (by using information provided by the ENB). This alternative approach is more consistent with the approach to be adopted for capex.

7.2.2 Wider capex wash-up

151. We note the proposal to extend the capex wash-up to all commissioned assets for FY15, which will ensure that the ultimate price path (after the wash-up applies) reflects a more accurate RAB at the start of the regulatory period. We support the proposal in principle, and will comment on the detailed mechanism in our forthcoming submission on the IM amendments.

152. As previously submitted, the ENA considers that forecasting for the DPP should be as accurate as possible. In our accompanying submission on Low Cost Forecasting Approaches we highlight some areas where we believe the proposed approach to the DPP reset is inconsistent in its use of information from within the current regulatory period, particularly where the most recent information available is not used, and/or, other wash-ups could be implemented but do not appear to have been considered.

7.3 Forecast purchases during regulatory period

153. We agree that the recoverable cost incentive provides a mechanism for recovering the additional costs incurred following an asset transfer, which occurs during the regulatory period. We consider that the avoided cost approach should in principle provide sufficient funds to cover:

a) Opex incurred by the ENB associated with the assets transferred

b) Return of and return on capital associated with the assets transferred

c) Return of and return on investment in the assets that are undertaken during the regulatory period.

154. In our submission on the Process and Issues Paper we highlighted potential issues with the recovery of c) above, and how this may act as a disincentive for transfers which are in the long term interests of consumers. The discussion in the Main Policy Paper does not appear to have considered our previous submission on this matter.

155. The Main Policy Paper indicates that the incentive mechanism applying to asset transfers will be relied upon for additional capex within the regulatory period. However the proposed approach for determining the value of the incentive mechanism provides no allowance for additional capex which may be incurred during the regulatory period because it is based on a year one counterfactual approach, which reflects investment in only those assets transferred.

156. In this respect we have previously suggested:

> *The ENA considers that avoided new investment charges that would also have arisen during the five year window, due to additional investment in the assets which have been transferred are legitimate recoverable costs, consistent with IM clause 3.1.3(1). As it is proposed that no capex allowances are included in the regulatory period for purchases which occur after 1 April 2015, it is necessary to include an avoided investment charge to reflect charges that would have been made, had the assets remained with Transpower, and the investment made by Transpower. The prevailing basis for determining new investment charges can be used to determine the appropriate charge.*
>
> *Absent this, a significant disincentive arises for potential asset transfers which are in the long term interests of consumers, but where investment is required in those assets within the regulatory period. The avoided Transpower charges at the time of the transfer will not provide compensation for subsequent investments.*
>
> *As stated above, it is our view that this is consistent with the intent of IM clause 3.1.3(1). We note that clause 3.1.3(1) also includes the requirement for the Commission to approve the*

recoverable cost allowance (as per 3.1.3(2)). Currently this approval process is prescribed in the DPP Determination, which includes, amongst other things, the evidence that must be included in DPP Compliance Statements pertaining to the recoverable cost allowance.[28]

157. It is now proposed that the Commission's approval process, noted above, becomes an ex ante process which provides additional scrutiny on how these avoided transmission charges are derived before they are reflected in prices.

7.4 Quality performance allowances

158. We note the intention to provide for adjustments to quality of service standards for Transpower assets purchased within the regulatory period. We support this proposal in principle and will provide more comment on the detailed proposals in our forthcoming submissions on the QoS Companion Paper and the Draft DPP Determination.

159. We note that it appears that there has been no consideration of the service quality performance for assets which have been, or are forecast to be, transferred prior to the next regulatory period. We submit that the historical performance of the assets for the entire reference period should be included when determining the quality of service targets, as this is the appropriate baseline against which future performance (ie: after the assets are transferred) should be assessed.

160. An adjustment for assets which are forecast to be transferred in the final year of the current regulatory period, where the transaction does not occur, could be introduced, similar to the proposed asset value wash up.

161. Quality standards should be set after including the historical performance of the assets purchased (over the reference period) prior to the regulatory period. The ENA supports additional adjustments to quality standards during the regulatory period, in the year of the purchase, which reflect the historical performance of those assets.

162. We consider this is a better outcome than excluding the performance of the assets entirely during the regulatory period, especially where the assets are transferred prior to the regulatory period. This ensures the responsibility for performance resides with the ENB, after ownership has changed.

7.5 Recommendations

163. The ENA recommends that in relation to assets purchased by an ENB from Transpower:

[28] ENA Submission on default price-quality paths from 1 April 2015 for 17 electricity distributors: process and issues paper, 21 March 2014, paras 174-176

a) The ENA supports the recoverable cost incentive for asset transfers from Transpower which allow avoided transmission charges to be recovered through prices for a period of five years

b) The proposals to prescribe how the avoided cost is calculated. ENA members are concerned that the proposed new approach will inadvertently exclude legitimate avoided transmission costs, and be impractical to achieve in practice. The current approach achieves reasonable outcomes and we consider it should be retained.

c) Purchases prior to the next regulatory period should be fully reflected in forecast costs when setting the price path. The current proposals do not adequately provide for opex (and can be improved by using ENB forecasts) and impose unreasonable constraints on capex which do not allow for differences between ENBs and Transpower (which compromise the incentive)

d) The costs associated with purchases during the regulatory period are addressed through the recoverable cost incentive, however the proposed specification of that incentive does not provide for the costs to be recovered in all instances.

e) The ENA considers that avoided new investment charges that would have arisen during the five year window due to additional investment in the assets which have been transferred are legitimate recoverable costs, consistent with the intent of the incentive.

164. We also note the wider capex wash-up proposed for FY15 and agree accuracy in RAB at the beginning of the regulatory period is important. We note that improved accuracy could be achieved in other forecasts used to set the DPP price path, where the most recent information available is not used, and/or, other wash-ups could be considered.

8. Treatment of uncertainty and risk

165. Our submission on the Process and Issues Paper (in section 6) considered how uncertainty and risk arise under DPP regulation, whether and how this should be addressed, and where appropriate shared between consumers and suppliers.

166. The ENA continues to be concerned that certain sources of uncertainty and risk are not adequately addressed in the DPP.

167. We acknowledge that the DPP is intended to be a relatively low cost regulatory mechanism and that in setting prices with reference to current and projected profitability, forecasts of input prices, opex and capex, CPI, depreciation and volumes are required. Our accompanying submission on the Low Cost Forecasting Approach Paper considers possible ways for improving forecasts in this respect.

168. The Main Policy Paper (and associated papers) address some, but not all, of the topics we have previously raised, as follows:

Paragraph reference[29]	Uncertainty or risk	Current consultation
6.1.1	Variance between forecast and disclosed CPI revaluations of Regulatory Asset Base	Considered in the Low Cost Forecasting Paper
6.1.2	Variance between forecast and outturn volumes	Not considered
6.2	Compliance risk	Partly considered in the Compliance Consultation Paper
6.3	Volume risk on recoverable and pass-through costs	Partly considered in the Main Policy Paper
6.4	Catastrophic risk	Considered in the Main Policy Paper

169. For the avoidance of doubt, in our accompanying submission on the Low Cost Forecasting Paper we consider the first item above (CPI forecasts in the context of the RAB revaluations) and the second item above (forecast volume risk). In our forthcoming submission on the Compliance Consultation Paper, we will set out our

[29] ENA, Submission on default price-quality paths from 1 April 2015 for 17 electricity distributors: process and issues paper, 30 April 2014

views on managing compliance risk (the third item above), including responding to the proposals for the recovery of pass-through and recoverable costs (including the fourth item above). The final item above (catastrophic risk) is addressed in section 6 of this submission.

9. Treatment of Orion New Zealand

9.1 Proposed transitional arrangements for Orion

170. The Main Policy Paper indicates that it is proposed that given Orion New Zealand (Orion) is currently subject to a CPP which will expire one year prior to the end of the next DPP regulatory period:

a) The DPP starting price that will apply at the end of the CPP will either be the price that applied in the final year of the CPP or another price which may be advised by the Commission

b) Starting prices do not need to be determined at this time

c) If prices are reset based on current and projected profitability, it is planned to:

i. apply the cost of capital IM

ii. apply forecast inflation for revaluations which is consistent with the cost of capital

iii. update opex and capex forecasts including accounting for efficiency gains during the CPP

iv. apply the same productivity-based rate of change that applies to others (although this will have no impact for the year in question)

d) Set quality standards by:

i. retaining the same specification of quality standards that apply in the CPP

ii. rolling forward the CPP trend (which is for improving reliability) into the next year

iii. introduce a revenue linked incentive, with no revenue at risk

e) Commence consultation with Orion at least 24 months prior to the end of the CPP (ie: by 31 March 2017).

171. The ENA considers that Orion is best placed to respond to the proposals for transitioning to a DPP at the end of the CPP.

9.2 Reducing uncertainty

172. The ENA supports proposals which reduce the uncertainty that currently exists as to how transitions between CPPs and DPPs may occur in practice. We note that the proposals included in the Main Policy Paper are directed solely at Orion and consider that additional certainty could be achieved if the final DPP decision included standard processes and criteria that would be employed for any ENB facing similar circumstances.

173. This is important as one of the considerations in applying for a CPP is what happens at the end of a CPP regulatory period. As noted in the Main Policy Paper, the Act provides the Commission with considerable discretion in this regard.

174. In our view, uncertainty could be reduced if the Commission were to signal in advance, and as soon as possible:

a) The timing of end of CPP consultations (including with the supplier affected and other interested persons) and the timing for decisions regarding approach and outcomes

b) The criteria to apply in determining whether CPP prices are rolled over, or other prices apply, and in the latter case, how these would be determined

c) The criteria for determining how the quality standards are set, and the timing of relevant decisions in this regard.

175. Absent the clarifications noted above, there is considerable uncertainty as the likely costs and benefits of applying for a CPP, which we consider compromises the effectiveness of the DPP/CPP regulatory model. We submit that the best place to provide these notifications is in the DPP Decision Paper, otherwise the CPP option as an alternative to the DPP is compromised, due to insufficient information about what the CPP option means in practice.

176. We also note that there is additional uncertainty for non-exempt ENBs as to the impact of Orion's performance on the FY21 DPP reset. It is possible that Orion will have four years on the CPP and one on a DPP, prior to the next DPP reset. It therefore will also reduce regulatory uncertainty if the Commission clarifies whether and how Orion's performance within this period will be taken into account when setting the next DPP for other businesses.

9.3 Recommendations

177. The ENA recommends that:

a) The uncertainty that currently exists about what happens at the end of a CPP should be reduced to ensure the DPP/CPP regulatory model is able to operate effectively. This can be achieved by further clarification as to the process and criteria that will be applied to determine the DPP price and quality standards at the end of a CPP. This clarification should be provided as soon as possible, and ideally, alongside the DPP Determination.

b) It will also reduce regulatory uncertainty if the Commission clarifies whether and how Orion's performance within this period will be taken into account when setting the next DPP for other businesses.

10. Customer service lines

10.1 Context

178. As noted in our submission on the Process and Issues Paper, customer service lines are emerging as a significant public safety issue. ENBs are not in general responsible for monitoring, maintaining and replacing these lines (although there are many exceptions to this general rule) but nor are customers aware that they are (in general) responsible for this line, or if they are aware they are not likely to be well-placed to monitor, maintain and replace it. As a result these lines often fall into disrepair, causing a public safety issue and giving rise to a dispute between consumer and ENB when work is required.

179. The ENA commissioned Energia to approximate the size of this problem and to recommend approaches to address it, and Sapere Research Group to recommend how these approaches could be implemented. The ENA has forwarded these reports to the Commission along with relevant legal opinions.

180. The Energia report recommends that ENBs offer one of two services (at their discretion) to address this public safety issue:

a) An Inspect, Maintain and Replace service or

b) An Inspect, Notify and Enforce service.

181. A necessary step for non-exempt ENBs to be able to implement these recommendations is that the Commission needs to provide a mechanism for recovering the associated costs.

182. ENBs are not well-placed to project the costs of providing services related to customer service lines as most do not have a history of providing this service. The ENA recommends that the Commission allows for ex post recovery of these costs for the upcoming regulatory period in a similar manner to the allowance for potential changes to the allowance for potential changes to AUFLS being considered by the Electricity Authority.

183. This would be a transition measure to allow ENBs and the Commission to gather information and data on the size of the costs. It is expected that it will take some time to determine the size of the problem. The ENA suggests that the Commission could require a pre-approval process to satisfy itself that ENBs are not over-recovering. If no allowance is made then this will impose a barrier to businesses moving ahead with this important public safety issue.

10.2 Recommendation

184. The ENA recommends that the Commission, in order to enable ENBs to address the public safety issues arising in relation to customer service lines:

a) Include a recoverable cost category for services implemented in relation to customer service lines, with a provision for pre-approval of any proposed cost recovery by the Commission.

b) Absent such a provision, the Commission will discourage ENBs taking proactive steps to manage a looming public safety concern as service lines age.