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18 July 2019

Dane Gunnell
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Commerce Commission
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By email only: regulation.branch@comcom.govt.nz

Dear Dane

AURORA ENERGY'S SUBMISSION IN RESPONSE TO THE COMMISSION'S DPP3 DRAFT DECISION

1 We welcome the opportunity to submit on the Commerce Commission's DPP3 draft decision and reasons paper.

2 We support the submission made by the Electricity Networks Association on behalf of New Zealand EDBs. However, we also wish to address several matters specific to Aurora's position:

2.1 The historic reference period for determining the capex allowance;

2.2 The IRIS incentive rate;

2.3 Quality standards; and

2.4 Smoothing the price path over the regulatory period.

3 This submission does not seek to address these matters comprehensively. Rather, these are matters on which we wish to engage with the Commission further between now and the September updated draft decision in order to determine an approach that better achieves the Part 4 purpose statement whilst remaining true to the low-cost character of the DPP.

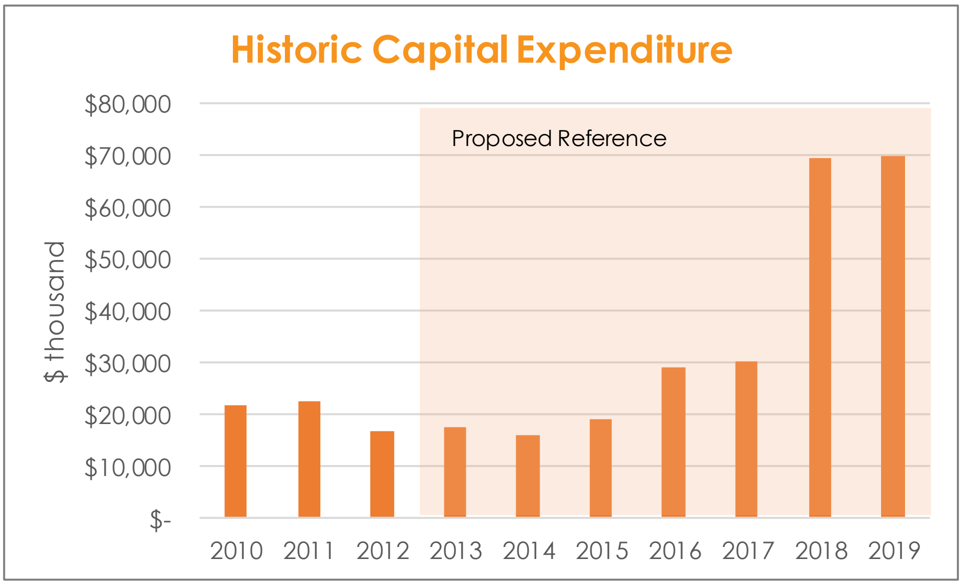
4 Because Aurora has committed to applying for a CPP in early 2020, it anticipates being on DPP3 only for one year. However, there is a risk that the current draft decision will substantially undercompensate Aurora in that year as a result of the recent step change in Aurora's expenditure requirements. That will make it difficult for Aurora to continue with its programme of investing in its network to improve reliability for the long-term benefit of consumers. Furthermore, the level of under-recovery implied by the draft decision has funding implications for Aurora, given the significance of the investment programme on which it has embarked.

5 However, the transition to a CPP also provides an opportunity for Aurora and the Commission to identify mechanisms that will allow Aurora to continue on its current investment pathway in the short-term, while ensuring the Commission has an opportunity to comprehensively evaluate the efficiency and prudency of Aurora's expenditure, including in year one of DPP3. We look forward to engaging with the Commission further on these issues.

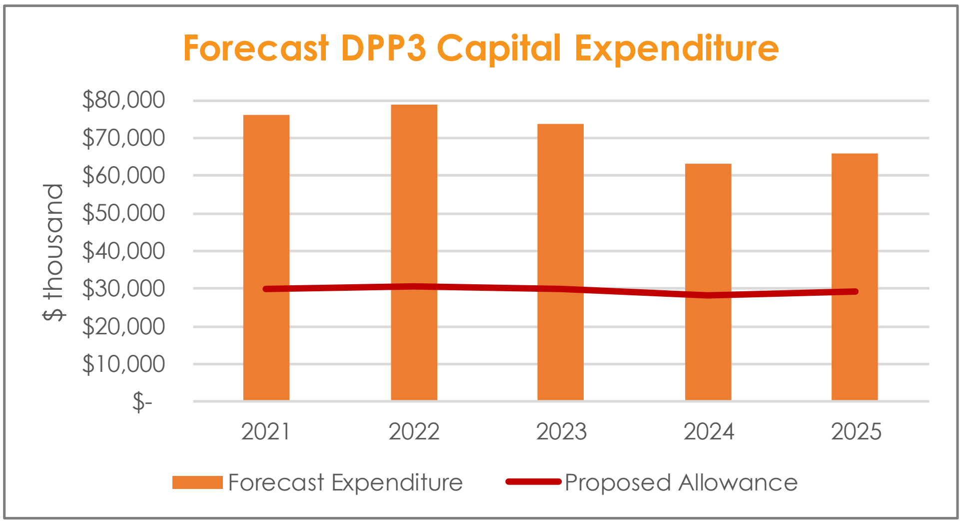
Historic reference period for determining the capex allowance

6 The draft decision proposes to cap EDBs' capex with reference to an historic reference period comprising the years 2013 to 2019. The Commission has explained that it prefers to use as long a reference period as possible in order to mitigate the effects of year-to-year volatility.

7 The use of an historic reference period is premised on the proposition that the most informative guide to future capex requirements is past capex requirements. However, the approach does not adequately capture cyclical changes in capital investment requirements. Specifically, in Aurora's case the use of a seven-year reference period significantly understates Aurora's future capex requirements. This is because of Aurora's low level of historic investment, which has resulted in deterioration of network assets that now requires remediation (as set out in detail in our 2018 AMP and 2019 AMP update). The step change in Aurora's capex as we address this historic under-investment is illustrated below.



8 The early years of the proposed historic reference period capture a number of years in which Aurora was under-investing. These years are therefore not an informative guide to Aurora's future capex requirements. Based on Aurora's AMP, capping Aurora's expenditure based on a seven-year period would result in a capex shortfall of ~$46 million in year one of DPP3.



9 One possible response is that more significant changes in capex are properly dealt with under a CPP application. Aurora has announced its intention to apply for a CPP, but the earliest opportunity it can do is after the commencement of the DPP, which means Aurora must be subject to the DPP (and its inadequate capex allowance) for at least one year.

10 In any event, the availability of the CPP option does not relieve the Commission of the obligation to determine a price path based on the best information available, within the constraints of the low-cost DPP framework. We understand that the Commission shares our view that the early years of its proposed historic reference period represent under-investment. Moreover, the Commission has at its disposal information that allows it to validate the need for

increased capex in DPP3, including (but not limited to) the independent WSP state of the network report commissioned by Aurora.

11 This information supports a shorter historic reference period that places more weight on Aurora's recent increase in capex. Relying on the information that the Commission has at hand, to set a shorter reference period, is consistent with the DPP's low-cost objective and better achieves the Part 4 purpose statement because it will allow Aurora to invest appropriately in the long-term interests of its consumers.

IRIS incentive rate

12 The draft determination proposes to equalise the opex and capex IRIS incentive rates, which would result in the capex incentive rate increasing from 15% to 26%.

13 In combination with the draft decision to adopt a seven-year historic reference period for capex, the increase in the capex IRIS incentive rate results in a substantial negative IRIS incentive adjustment (penalty).

14 The imposition of this penalty is not consistent with the Part 4 purpose statement. The role of the IRIS is to incentivise EDBs to achieve efficiencies over the course of the regulatory period. But the IRIS incentive only works if the expenditure allowance is itself fairly calibrated to the EDBs' requirements. If not, then variance between actual and allowed expenditure does not represent efficiencies or inefficiencies but rather the results of a poorly fitted forecast.

15 Increasing the capex IRIS incentive in circumstances where there is reason to believe that the capex allowance does not represent actual capex requirements in the next period means the IRIS does not function as intended and simply penalises Aurora arbitrarily.

Quality standards

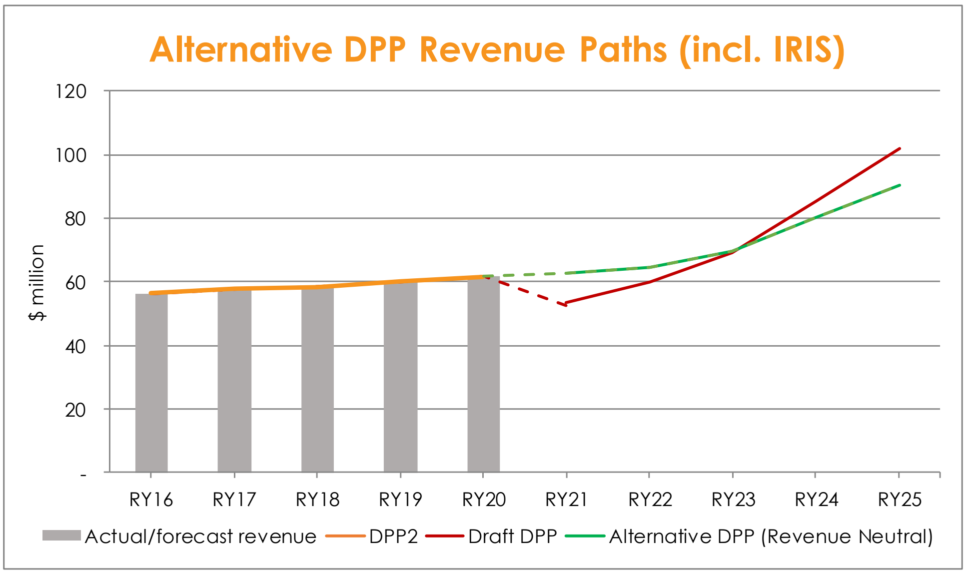
16 The draft decision proposes to cap inter-period changes in unplanned SAIDI and SAIFI at 5%. The stated reason is to ensure that EDBs are not rewarded with an increased limit for deteriorating reliability in a previous period. Aurora supports this in principle. However, it is also important to ensure that quality standards are reasonably capable of compliance. The Commission is not achieving anything by imposing quality standards that cannot be achieved. In fact, it would be inappropriate to set limits that essentially entailed a future breach of the price-quality path, given the significant financial, reputational and personal consequences of a contravention.

17 Accordingly, while we support setting a cap on inter-period changes, we think the proposed 5% cap exposes EDBs to too much risk of quality standards with which they cannot reasonably comply. We would therefore propose as an alternative a cap of 15%.

Smoothing the price path

18 The draft decision proposes to adopt an X-factor for Aurora of 8.9% to help minimise price shocks to consumers. Absent this smoothing, the Commission says that Aurora's starting price adjustment would have been +24%.

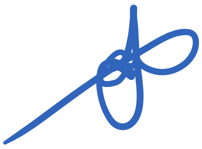
19 We support measures to mitigate price shocks to consumers. However, the proposed smoothing of the price path does not consider the impact of IRIS penalties as a consequence of Aurora's over-spend in DPP2. Once these penalties are taken into account, the price adjustment is significantly less than the draft decision indicates.



20 We recommend revisiting the smoothing of Aurora's price path taking into account the effect of IRIS penalties over the course of DPP2.

21 In light of Aurora's intended CPP application next year, there are clearly some transitional issues that need to be considered. We look forward to engaging productively with the Commission on how the various overlaps might be best managed for the long-term benefit of consumers.

Yours sincerely



Alec Findlater
General Manager, Regulatory & Commercial

Submission

Commerce Commission: Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision

18 July 2018

Table of Contents

1 Executive summary

1.1. We are pleased that the Commission has *"generally retained approaches from DPP2 where they remain fit for purpose"*[1]. However, in certain instances, we question whether the proposed shift away from the current approach serves to better promote the long-term benefit of consumers, or whether the proposed change instead only adds complexity to the default price-quality path (DPP) framework.

1.2. Our main concerns are:

- the decision not to undertake an historical productivity assessment to support the setting of the partial productivity factor;
- that some of the tests proposed for scrutinising capital expenditure do not accurately indicate whether the AMP forecasts are reasonable or not;
- the use of historical average capital expenditure as a default fall-back;
- that, while we acknowledge an alternative rate of change is necessary in Aurora's case, the analysis undertaken to determine the alternative rate of change does not allow for the impact of IRIS incentive adjustments (penalties) on the price that consumers face, nor does it consider that distribution prices make up just a proportion of the charges that consumers face for electricity; and
- that the draft decision may introduce unintended incentives on distributors to push the boundaries of safe working practices, by the way in which the 'additional notice' and 'intended interruption' mechanisms have been framed.

2 Operating expenditure

Base-step-trend approach to forecasting opex

2.1. We generally support retention of the base-step-trend approach to forecasting operating expenditure (opex). However, we do have some concerns about the partial productivity factor component of the proposed methodology, which we discuss further in paragraphs 2.4 to 2.7 below.

Fire and Emergency New Zealand levies

2.2. We support the proposal to treat Fire and Emergency New Zealand (FENZ) levies as a recoverable cost. FENZ levies are a cost that distributors have no control over and therefore they should be treated on the same basis as other regulated levies. In addition, we note that the new FENZ levy arrangements have yet to come into force and there is the potential for them to change substantially over the DPP3 period.

Input price inflator

2.3. In our submission on the Commission's Issues Paper, we suggested that *"a transport component should be incorporated (with a possible weighting of between 5% and 10% scaled according to ICP density) to more adequately reflect the inputs to operating expenditure."*[2] After further consideration we accept the Commission's proposal to retain the approach from DPP2 (a 60% weighting of the all-industries LCI forecast and 40% weighting of the all-industries PPI forecast).

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[1] Reasons Paper, paragraph X14

[2] Aurora Energy Limited. (2018). Submission – Commerce Commission: Default price-quality paths for electricity distribution businesses from 1 April 2020 – Issues Paper, 20 December 2018, paragraph 4.7.

Partial productivity factor

2.4. We disagree with the proposal to set an opex partial productivity factor (PPF) of 0%. We maintain our view that the Economics Insights study that established a -0.25% PPF for DPP2 should be updated and used to determine a PPF for DPP3.

2.5. While we agree that, in a workably competitive market, productivity improvements would be expected (and therefore a non-negative PPF), the draft determination does not taken into account the findings by NERA (presented by the Electricity Networks Association (ENA)) that "*if opex is forecast using the same outputs that demonstrate negative historical productivity, and forecasts of that measure are still negative, EDBs will be denied efficient cost recovery unless the opex PPF is also negative*"[3]. We note that the negative PPF found in Economics Insights' study for DPP2 does not necessary reflect that distributors are becoming less productive over time, but that the model used to measure productivity does not provide a complete measure of the outputs produced by distributors.[4]

2.6. Further, an historical productivity assessment is rejected because "*we question whether past productivity changes have been an appropriate predictor of future gains*."[5] No further explanation is provided as to why historical productivity changes are not an appropriate predictor of future gains. As noted by NERA, the PPF needs to reflect the underlying trends in productivity,[6] and therefore we consider using an historic long-term series of productivity is appropriate.

2.7. Overall, the approach to determining a PPF described in the draft decision seems arbitrary. The approach relies on PPFs set by overseas regulators with no discussion of the relevance of these PPFs for New Zealand distributors. In our view, an approach that is objective and stable over time is needed; one that can continue to be applied to DPP decisions in the future.

3 Capital expenditure

Disaggregation of forecasts into five expenditure categories

3.1. We do not oppose the proposed disaggregation of capital expenditure (capex) forecasts into five expenditure categories. We agree that this is an appropriate evolution of the light-handed scrutiny applied in DPP2. However, we have some concerns that the individual expenditure categories may be difficult to scrutinise accurately. We discuss these concerns further in the following sections.

Capping of aggregate capex at 120% of historical capex

3.2. In principle, and assuming an absence of other information that the Commission might have to hand that it may rely on[7], we agree with the proposal to cap aggregate capex forecasts at 120% of historical expenditure. As a final scrutiny proxy, this remains consistent with the approach taken in DPP2.

Scrutiny of AMP capex forecasts and use of historical average expenditure as a default fall-back

3.3. While we agree that scrutiny of AMP forecasts of capex is necessary, we are concerned that:

- some of the tests that are proposed do not accurately indicate whether the AMP forecasts are reasonable or not; and

[3] NERA (2019), Economic considerations for forecasting productivity in the DPP. Prepared for ENA in support of ENA's submission on the Commission's Issues Paper, paragraph 3g.
[4] NERA (2019), Economic considerations for forecasting productivity in the DPP. Prepared for ENA in support of ENA's submission on the Commission's Issues Paper, paragraph 3d.
[5] Reasons Paper, paragraph A121.
[6] NERA (2019), Economic considerations for forecasting productivity in the DPP. Prepared for ENA in support of ENA's submission on the Commission's Issues Paper, paragraph 13a.
[7] For example, in Aurora's case, the independent WSP state of the network report commissioned by Aurora.

- the use of historical average expenditure as a default fall-back (when a distributor's AMP forecast does not pass scrutiny) is not appropriate.

3.4. We discuss our concerns about the specific scrutiny proposed, below. However, in general terms, the scrutiny tests proposed are reasonably blunt instruments and may lead to a distributor failing to pass scrutiny when its forecasts are justifiable. In some cases, such as applies to Aurora, distributors will have specific circumstances that are best dealt with under a CPP. We are concerned, however, that the blunt nature of proposed scrutiny will violate the purpose of DPP/CPP regulation[8] by encouraging more distributors to apply for CPPs.

3.5. We disagree with the proposal to limit each category's expenditure to the historical average when a distributor's AMP forecast is considered to fail scrutiny. While we agree some limitation should apply to failed scrutiny, we consider that capping the expenditure allowance at historical average:

- can lead to expenditure being capped well below levels that cost drivers would suggest is reasonable;
- can lead to a substantial reduction in the capex allowance for the category relative to forecast, even if the distributor only fails scrutiny by a small margin; and
- is a harsh penalty where scrutiny is imprecise in nature.

3.6. Further, we observe that in discussion of capping aggregate capex at 120% of historical capex, the Commission notes (emphasis added):

> "***Applying a simple cap at the expenditure category level****, rather than at an aggregate level,* ***would penalise distributors that were experiencing justified growth and decline across different expenditure categories****. For example, a distributor that was moving from a period of system growth to spending more on ARR would have their ARR spending capped near historical levels, and their system growth forecast accepted. This would result in an overall forecast amount that is potentially much lower than their AMP forecast and what they were provided under DPP2."*[9]

3.7. While the proposed scrutiny is intended to determine whether a distributor's forecast expenditure across different expenditure categories is broadly justified, the tests are unduly blunt and may not accurately capture a justified move between expenditure in different categories.

3.8. Therefore, we consider that capping expenditure in a capex category at 100% of historic average expenditure when a distributor fails scrutiny is not appropriate.

3.9. We note that three options have been considered for limiting expenditure when an AMP forecast does not pass scrutiny:

- *"Using a distributor's historical average expenditure.*
- *Capping their forecasts at some level above their historical average expenditure—with capping options that include applying the cap each year of the DPP3 period, or capping expenditure in aggregate across the full period. There are also different kinds of caps, including a sliding scale cap, uniform dollar cap, and uniform percentage cap.*
- *Calculating an amount that is consistent with independent assessments of cost drivers."*[10]

3.10. In our view, wherever possible, expenditure forecast should be capped (when a distributor fails scrutiny) at an amount consistent with independent assessments of cost drivers. When

[8] Section 53K of the Commerce Act sets out that the purpose of the DPP/CPP regulation is *"to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances".*

[9] Reasons Paper, paragraph B89.

[10] Reasons Paper, paragraph B49.

this is not possible, expenditure should be capped at some level above the historical average that considers the degree to which the distributor has failed scrutiny. We discuss options for capping expenditure in such circumstances, below.

Scrutiny of distributors' past forecast performance

3.11. We support the proposal to test distributors' forecast accuracy within a broad boundary. We consider that if a distributor fails this test, some multiple of historical average expenditure should be used as a fall-back for all expenditure categories where the distributor is forecasting a relative increase in expenditure.

3.12. We believe this approach provides a reasonable gateway test that incentivises improvement in forecast accuracy.

Scrutiny of consumer connection category

3.13. Two tests are proposed to scrutinise consumer connection capex:

- the first test assesses whether the distributor is forecasting growth in residential connections greater than both its historical ICP growth and forecasts of population growth for its area; and
- the second test assesses whether the distributor's forecast per-connection spend is greater than 150% of historic per-connection spend.

3.14. We support the proposed scrutiny of consumer connection capex forecasts. When forecasts of population growth and historical ICP growth are combined with the per-connection expenditure test, a reasonably balanced view of the adequacy of the consumer connection capex forecast is obtained. We note that the proposed150% threshold (150% of historic per-connection expenditure (in real terms)) appears somewhat arbitrary; however, we agree that a wide tolerance is needed to account for variation in per-connection costs across different connection types.

3.15. We disagree with the proposed caps on consumer connection capex where forecasts fail scrutiny. Instead we consider that:

- if a distributor fails the consumer connection growth test, its consumer connection growth should be limited to an amount consistent with forecast population growth; and
- if a distributor fails the per-connection expenditure test, its per-connection expenditure should be limited to 120% of its historical per-connection expenditure.

3.16. As noted above, we believe that the expenditure caps should be consistent with independent assessments of cost drivers, when appropriate. We consider that population growth is a clear driver of consumer connections, and therefore should be used as a basis for capping consumer connection capex when a distributor's consumer connections forecast does not pass scrutiny. We note that the Commission decided not to take this approach in the draft decision *"because we would need to consider how it would interact with the next test we propose, and because it would not impact the overall results based on the 2018 AMPs."*[11] We do not consider there are any issues with the interaction between the two connection tests, as the per-connection expenditure test is based solely on historical per-connection expenditure.

Scrutiny of system growth category

3.17. The draft decision proposes distributors' forecast system growth expenditure be scrutinised for consistency against forecast increases in zone substation transformer capacity over the same period. We do not believe this proposed method of scrutiny is appropriate because:

- **The Commission's own analysis shows there is a very weak relationship between zone substation capacity growth and zone substation capex,** admitting that *"few distributors are forecasting expenditure on zone substation capacity that appears proportional to*

[11] Reasons Paper, paragraph B127.

historical expenditure on zone substation capacity"[12]. Indeed, Figure B7 of the Reasons Paper shows that no distributor is forecasting zone substation expenditure per-MVA of new capacity relative to historic of anywhere near 100% (the closest being Top Energy and Vector Lines at just over 200%). This suggests to us that either there is a very weak relationship between zone substation capacity growth and zone substation capex within a five year control period, or all distributors are doing a very poor job at forecasting their zone substation capital expenditure.[13] No analysis has been provided to determine whether it is the former or the latter. We suggest it is due to the lumpy nature of investment and, therefore, a relationship only exists over the very long term; and

- **Zone substation capex does not reflect system growth capex in its entirety.** Zone substation capex is just one component of system growth capex that, on average, makes up about 30% of total system growth expenditure.[14] However, there is substantial variance from year-to-year (and between distributors) in zone substations' share of total system growth expenditure. For example, while Aurora's zone substation capex accounted for around 50% of its system growth capex in total over the period 2014-2019, it only made up 0.1% of system growth capex in 2018, but was 96.5% of system growth capex in 2015.[15] It is not clear how such a volatile component of system growth capex can be used to provide a good indicator of the internal consistency of the AMP forecasts for total system growth capex.[16]

3.18. We submit that an alternative method for scrutinising distributors' of system growth expenditure forecasts is required.

3.19. We agree with the conclusion that maximum coincident system demand is not an appropriate indicator of the reasonableness of forecast system growth capex.[17] However, we disagree with the assertion that system growth capex should be driven by maximum coincident system demand. Maximum coincident system demand is a poor indicator of system growth capex when distributors have subnetworks or when coincident GXP demand is growing quicker in some parts of the network than others.

3.20. We disagree that a distributor failing system growth expenditure scrutiny should have its system growth expenditure allowance capped at 100% of historical levels. As noted by the Commission, some distributors that fail scrutiny "*are forecasting significant increases in system growth expenditure, so are materially penalised*"[18]. We do not think that the approach is consistent with the Part 4 purpose, as it cannot be reasonably concluded that these distributors' system growth expenditure forecasts are so unreasonable that they should be materially penalised.

3.21. We think that the cap on system growth expenditure needs to ensure that any penalty is commensurate with the "unreasonableness" of the forecast. However, we reiterate that the proposed method of scrutiny is not appropriate. In addition, we believe there may be some errors in the calculations that, at least in Aurora's case, would make its apparent failure of this test much less severe if the calculation errors were corrected.

3.22. We request that the Commission checks its zone substation capacity (MVA) inputs and calculations in its capex projections feeder gating model. Some of Aurora's substations (and potentially the substations of some other distributors) appear twice in the 'Inputs – MVA' and

[12] Reasons Paper, paragraph B137.
[13] Another reason could be due to errors in the calculation of historic per-MVA substation expenditure. We discuss this in section 4.2.25).
[14] Reasons Paper, paragraph B136.
[15] We also note that four distributors (Eastland Network, Nelson Electricity, The Lines Company, and Unison Networks) are forecasting zero zone substation capex over the DPP3 period but are forecasting non-zero system growth capex over the same period. Therefore, the proposed method of scrutiny provides no scrutiny to these distributors. (We do note, however, that these distributors are forecasting drops in system growth expenditure, so regardless of the form of scrutiny applied these distributors will be allowed their AMP forecasts for system growth capex).
[16] Reasons Paper, paragraph B136.
[17] Reasons Paper, paragraph B133.
[18] Reasons Paper, paragraph B138.

'Calculations – MVA' sheets due to changes in naming conventions.[19] Because of this, the calculation of historic average expenditure on substations (per-MVA) appears to count investments in those substations that have not actually occurred, reducing the historic per-MVA expenditure below what it should be.[20]

Scrutiny of asset replacement and renewal (ARR) and reliability, safety and environment (RS&E) categories

3.23. The draft decision proposes to assess ARR and RS&E capex against forecast depreciation. We do not support this proposed scrutiny. The industry tends to have renewal capex well below depreciation. In addition, we support the Commission's comments on the weakness of this test:

- *"the relationship between ARR and depreciation… is imperfect"*[21]
- *"there are significant limits to this assumption [that over the long-term, ARR expenditure should be in the same ball-park as depreciation], due to the cyclic nature of replacement and renewal, long-life of the assets, and 'snapshot' nature of the AMP forecasts"*[22]
- *"We would not expect distributors to maintain a ratio of 100% ... the ARR can reasonably be somewhat lower or higher than depreciation, and looking at this ratio can give the misleading impression that a new network is under-investing, while an old one is over-investing."*[23]

3.24. In our view, if such a test is to be used, it needs to allow for the distributor's asset condition (disclosed in schedule 12a of Information Disclosure). The Commission noted a preference to include a gating test that compared asset condition data in schedule 12a with forecast ARR expenditure, but found that *"the data is detailed and challenging to work with, and does not readily translate into a single cost metric that we can scrutinise"*[24]. We suggest that a qualitative assessment of asset condition could be undertaken, as a second gating test, to assess any distributors who failed the initial test comparing ARR expenditure against forecast depreciation. Qualitative assessment could be used to determine whether it was reasonable for the distributor's forecast of ARR and RS&E to be greater than 125% of depreciation and set an appropriate higher threshold to test that distributor against.

3.25. Further, considering other information about any distributor's network asset condition, that the Commission has to hand and may rely on, should inform the Commission's decision on the appropriate allowance. Such an approach is consistent with the relatively low-cost purpose of DPP regulation.

3.26. For reasons set out above, we do not agree with ARR expenditure being capped at 100% of historical levels if a distributor fails scrutiny. We consider that the cap should be determined based on relevant cost drivers.

3.27. If the proposed test is retained, then we consider that any distributor that fails the test should have expenditure capped at 125% of forecast depreciation. We note that the Commission suggests this alternative in its Reasons Paper.[25]

3.28. If the asset condition of a distributor (as we suggest in paragraphs 3.24 and 3.25) is also considered, then the cap should be set at some reasonable level higher than 125% of forecast depreciation, as is appropriate for that distributor's asset condition.

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[19] For example, Aurora Energy's Ward Street substation is included twice as 'Ward St' and 'Ward Street'. Other Aurora substations that appear twice include Anderson's Bay, Clyde/Earnscleugh, Kaikorai Valley, Maungawera, North East Valley, and Smith Street.

[20] Because the Commission's calculations (correctly) only count increases in substation capacity (so do not count reductions in capacity), the effect of including substations twice is not zeroed out.

[21] Reasons Paper, paragraph B153.

[22] Reasons Paper, paragraph B144.

[23] Reasons Paper, paragraph B151.

[24] Reasons Paper, paragraph B145.

[25] Reasons Paper, paragraph B152.

Sliding scale cap for minor categories of capex

3.29. We support the proposed approach of using a sliding scale cap of 120-200% for other categories of capex. We note that this approach is consistent with the approach taken in DPP2.

Historical reference period for assessment

3.30. We oppose the proposal to use a seven-year historical reference period (2013-19) in its final decision. We consider, as a minimum, that consistency should be maintained with the approach taken in DPP2, and a five-year reference period used.

3.31. The Commission considers that using a longer period is appropriate given the volatility of capex. We do not agree.

3.32. Distributors' investment needs are not linear, and flexing of investment, relative to historical levels is periodically required, not the least to maintain levels of reliability. Recent expenditure trends are likely to be more reflective of current needs and extending the reference period serves only to frustrate the recognition of distributors' current or emerging needs.

3.33. In addition, the DPP regime is still relatively immature (in terms of measures, data, and definitions), making it even more important to use a more recent period as the 'anchor'. Once the DPP regime has been operating successfully over a longer period, and more data has built up, a longer reference period may gain some validity.

3.34. We submit that the Commission should revert to using the most recent five years (2015 - 2019) as the historical reference period for assessment.

Scrutiny of capital contribution forecasts

3.35. We support the proposal to not independently scrutinise capital contribution forecasts. Separate scrutiny would, in our view, increase the likelihood of forecast error. In addition, our experience is that capital contributions are difficult to forecast with precision and are impacted by external factors over which distributors have limited control.

Allowance for cost of financing

3.36. We support the Commission's proposal to include an allowance for cost of financing, scaled according to the proportion of accepted capex.

4 Alternative rate of change

4.1. While we acknowledge that an alternative rate of change is necessary in Aurora's case, we do not support the methodology that has been used for determining the alternative rate of change because:

- it does not allow for the impact of IRIS penalties on the price that consumers face; and
- no consideration seems to have been given to the fact that the prices charged by distributors make up just a proportion of the total charges that consumers face for electricity.

4.2. In conjunction, these two factors mean that the alternative rate of change proposed for Aurora is not consistent with Part 4 of the Commerce Act and does not lead to the combination of starting price and rate of change that is best for consumers.

4.3. The Commerce Act 1986 sets out that the "*Commission may set alternative rates of change for a particular supplier… if, in the Commission's opinion, this is necessary or desirable to minimise any undue hardship to the supplier or to minimise price shock to consumers*"[26].

4.4. The draft decision proposes to set an alternative rate of change when the increase in revenue in the first year of the DPP would otherwise exceed +10% in real terms to avoid price shock to

[26] Commerce Act 1986, section 53P(8).

consumers.[27] The only distributor affected by this limit in the draft decision is Aurora. An alternative rate of change of -8.9% is proposed for Aurora, to avoid an unsmoothed increase in revenue of +24%, in real terms, in the first year of the DPP. The alternative rate of change has been set to smooth the increase in real allowable net revenue over the regulatory period.

The impact of IRIS incentive adjustments on the price consumers face

4.5. Allowable net revenue is not the price that consumers face. In addition to its allowable net revenue, a distributor can also recover pass-through and recoverable costs from consumers. Recoverable costs include IRIS incentive adjustments for opex and capex, which are forecastable based on actual and forecast opex and capex during the DPP2 regulatory period. These IRIS incentive adjustments can be substantial (Aurora's is forecast to be circa -$18 million in 2020/21) and vary from year-to-year.

4.6. The impact of IRIS incentive adjustments on revenue needs to be considered when determining the need for, and the magnitude of, an alternative rate of change. This will provide a more realistic indication of the price changes that consumers will face, and hence a proper basis to determine whether any price shock would occur. We consider that this approach would be more consistent with the proposal to limit annual increases in gross 'forecast revenue from prices' (revenue including pass-through and recoverable costs) to +10% (discussed further section 8 below).

4.7. We note that Aurora's proposed alternative rate of change (-8.9%) would likely lead to price reductions for consumers in 2020/21 due to the forecast IRIS incentive adjustment in 2020/21. This would potentially be followed by substantial increases in subsequent years, as IRIS penalties roll off (and before anticipating the outcome of Aurora's forthcoming CPP application).

4.8. If the impact of IRIS incentive adjustments are considered when determining the alternative rate of change, then we expect that Aurora's alternative rate of change would be much closer to zero (if an alternative rate of change was needed at all). This would likely lead to a much smoother price trajectory for consumers over the DPP3 regulatory period / forthcoming CPP period.

The proportion of distribution charges that make up the price consumers face

4.9. The test in the Commerce Act refers to "price shock to consumers". The draft dcision does not appear to consider that prices charged by distributors make up just a proportion of consumers' total electricity charges. For example, average distribution charges only comprise around 27% of a residential consumer's electricity bill.[28] Therefore, a 10% increase in distribution charges would lead to about a 3% increase in the consumer's bill. Furthermore, Aurora's residential distribution charges (particularly on its Dunedin network) are among the lowest in New Zealand and make up a lower proportion of residential consumers' electricity charges than the average across New Zealand.[29] This means the impact will be even lower (on average) for Aurora consumers.

4.10. Consideration should be given to increasing the threshold (currently an increase in the revenue limit exceeding +10% in real terms) for determining an alternative rate of change so that is it more consistent with the Act.

[27] Reasons Paper, paragraph 6.10.

[28] Electricity Authority (2018), Electricity in New Zealand, p13. Available here: https://www.ea.govt.nz/dmsdocument/20410-electricity-in-new-zealand

[29] See, for example, the Ministry of Business, Innovation and Employment latest Quarterly Survey of Domestic Electricity Prices for an indication of retail, lines company and energy and other residential charges by lines company areas (available here: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring/).

5 Single CPP annual application date

5.1. We support the proposal to set a single CPP application date in July of each year, except 2024 (29 March). This change allows for later submission of CPP applications than exists now and removes the need for an IM exemption application to defer the application window.

6 Efficiency incentives

6.1. We conditionally support the proposal to set the capex retention factor equal to the opex retention factor (-26%). We agree that equalisation of the incentive rate should limit the extent to which distributors prefer capex solutions over opex, when there are alternatives available.

6.2. However, our support for equalised incentive rates is conditional on reasonably realistic expenditure allowances being set. Any increase in the capex retention factor must be accompanied by a reasonable assurance that the expenditure allowances set are adequate and meet the needs of the distributor. Where the expenditure allowance is not-fit-for purpose, the IRIS ceases to be an efficiency incentive and becomes something else entirely.

7 Proposed reopener for large unforeseen new connections

7.1. We support, in principle, the introduction of a reopener for unforeseen major consumer connection capex. Major consumer connection capex is uncertain, especially for large connections where decarbonisation initiatives are at play. However, we have reservations about the 5% of net annual revenue threshold for a reopener request to be accepted.

7.2. The Commission has stated that it considers the 5% threshold "*appropriate for distributors to absorb uncertainty of lesser amounts so that the change does not result in an excessive number of reopeners and because of the asymmetric nature of reopener provisions.*"[30]

7.3. We consider that a percentage threshold effectively sets a sliding scale that benefits smaller distributors and disadvantages larger distributors. For an equivalent investment (e.g., a dedicated zone substation) we question why it is appropriate for small EDBs to be compensated for their investment, while larger EDBs are required to make do (and probably face IRIS penalties in addition).

7.4. We recommend that a defined threshold dollar value is set (such as $2 million), or a threshold that is equal to the lesser of 5% of net annual revenue or a defined threshold value.

7.5. We further note that this 'sliding scale' issue extends to contingent projects under the CPP IMs.

8 Revenue cap with wash-up

8.1. While we generally accept the proposed approach to the price setting and wash-up processes in implementing the revenue cap, there are two areas where we disagree with the proposed approach:

- the proposed limit on the percentage annual increase in forecast revenue from prices; and

[30] Reasons Paper, paragraph G13.

- the formula proposed the change in CPI which forms a part of the actual net allowable revenue calculation.

Limit on the percentage annual increase in forecast revenue from prices

8.2. We accept, in principle, a regulatory control to limit price shock arising from step increases in forecast revenue. As acknowledged in the Reasons Paper, there are many factors that drive changes in distribution revenues, such as changes in billable quantities, IRIS recoverable costs, reliability incentive adjustments, annual wash-up adjustments, and the possible implementation of a revised Transmission Pricing Methodology.

8.3. The draft decision proposes a 10% limit on the annual increase in forecast revenue from prices. We consider that the limit should be applied in constant price terms, rather than nominal as proposed.[31] This would exclude the impact of CPI on the limit, and would make the limit more workable in an environment where inflation may be greater than it is now.

8.4. The Commission also notes that it could specify alternative values for specified distributors in the final decision. We agree that there may be need for an alternative value for some distributors, in specific circumstances. However, we are concerned that no insight has been provided as to how the need for an alternative value would be determined and how that alternative value would be set.[32] We believe the proposed criteria should set out in more detail.

8.5. We note that the limit on the annual increase in forecast revenue from prices will not apply in the first year of DPP3 (due to data limitations) but that a limit may be imposed in the first year of subsequent DPP periods instead of setting alternative rates of change. We agree that this limit may be more effective at minimising price shock to consumers than setting alternative rates of change. This is because this limit allows for the impact of all revenue on the prices faced by consumers, rather than focussing on allowable net revenue (which the alternative rate of change is based on). However, it is essential, if a limit on price increases in the first year of subsequent DPPs is imposed, that the limit is not set too low (and therefore prevent a distributor from recouping its reasonable costs).

Calculation of wash-up amount for an assessment period

8.6. While we are largely comfortable with the wash-up mechanism proposed, we harbour concerns about the use of March quarter CPI for the base.

8.7. CPI for the March quarter will only be defined in mid-late April, after the regulatory period has come to an end. This may impact on a distributor's ability to complete its annual compliance statement and arrange for the necessary audit to be undertaken within the regulated timeframes.

8.8. In our view, this could be avoided by using a December CPI base, and amending the formula to read as follows:

$$\Delta CPI = \frac{CPI_{Mar,t-1} + CPI_{Jun,t-1} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-\mathbf{2}} + CPI_{Jun,t-\mathbf{2}} + CPI_{Sep,t-\mathbf{2}} + CPI_{Dec,t-\mathbf{2}}} - 1$$

9 Quality reference period and inter-period change

Setting the reference period

9.1. We acknowledge the Commission's response to our initial submission regarding the use of a stable reference period and accept the decision to adopt a 10-year rolling reference period.

[31] Reasons Paper, paragraph H47

[32] We also note that the limit on annual increase would apply to CPPs as well. It is essential that the Commission determines how and when an alternative limit value should be applied as we consider an alternative value is much more likely to be required for a distributor applying for a CPP (than those under a DPP).

9.2. The Commission has indicated in the Reasons Paper that it considers that "*a minimum reference period of 10 years best reflects the current underlying level of reliability performance*"[33] and "*rolling over to the most recent 10-years is better aligned with expenditure incentives*"[34].

9.3. In its notice to supply information given under section 53ZD(1)(e) and 53ZD(1)(f) of the Commerce Act 1986, dated 28 June 2019, the Commission has requested audited data from distributors for the period 1 April 2008 to 31 March 2019.

9.4. We request that the Commission confirms that its intention is still to use the most recent 10-years' data for setting the reference period, which would see it using the quality data for the period 1 April 2009 to 31 March 2019.

Capping the inter-regulatory period change for unplanned reliability

9.5. We agree that it is inappropriate that deteriorating performance should be rewarded with more relaxed standards, and improved performance penalised.

9.6. To that end, we support in principle the proposed approach to addressing this issue through the introduction of a cap on unplanned reliability targets between DPP2 and DPP3, as that mechanism creates an appropriate balance between allowing quality standards to be flexible, while not unduly rewarding deteriorating performance, or conversely, penalising improving performance.

9.7. However, it is also important to ensure that quality standards are reasonably capable of compliance. The Commission is not achieving anything by imposing quality standards that cannot be achieved. In fact, it would be inappropriate to set limits that essentially entailed a future breach of the price-quality path, given the significant financial, reputational and personal consequences of a contravention.

9.8. Accordingly, while we support setting a cap on inter-period changes, we think the proposed 5% cap exposes EDBs to too much risk of quality standards with which they cannot reasonably comply. We would therefore propose as an alternative a cap of 15%.

10 Identification and treatment of major events

Major events are identified on a three-hour rolling basis

10.1. While we accept the Commission's rationale for a move away from a calendar day approach to identifying major events, and moving to rolling periods, we question the overall gain of the proposed change.

10.2. The release of the template model for reliability assessment has proved useful in understanding how the application of a rolling window will in practice operate.

10.3. When looking at identification of major events in isolation, it appears from our analysis of Aurora's data (provided to the Commission for the purposes of the Draft Determination), that identifying major events on a three-hour rolling basis results in fewer major events than is the case under the current calendar day approach.

10.4. In our view, identification and enhanced analysis of major events by distributors is beneficial to their business and supports good asset management. This view appears to be mirrored by the enhanced major event reporting requirements that are proposed for DPP3, which we support. A move to a three-hour rolling identification of major event days would appear to reduce the number of events that are identified, thereby reducing the number of investigations that would be undertaken.

10.5. We therefore question whether there is in fact sufficient value in changing the current approach to the identification and treatment of major event days.

[33] Reasons Paper, paragraph J11
[34] Reasons Paper, paragraph J12

Major event reporting

10.6. We continue to support enhanced reporting for major events and acknowledge that the Commission has addressed our concerns regarding a distributor's ability to include all required information in its annual compliance statement when a major event occurs close to the end of the disclosure year.

11 Quality standards

11.1. In short, we largely support the changes to setting quality standards that has been proposed.

11.2. The proposed amendments to the quality standards, when viewed as a whole, appear to better incentivise distributors to take positive steps to manage their reliability, while at the same time, continue to invest in the maintenance of their networks.

11.3. The key challenge, which remains unsolved in our view, is better aligning quality standards, asset condition, and investment needs for each distributor, all within the context of the low-cost DPP framework. We consider that the efficacy of making future decisions on the basis of misaligned historic information is diminishing.

SAIDI and SAIFI as quality standards

11.4. While we agree that SAIDI is an important measure of network reliability, we do not agree that SAIFI is to the same extent and would urge the Commission to thoroughly consider whether SAIFI is an appropriate compliance metric.

11.5. The Commission acknowledges that "*interruption duration (SAIDI) is a function of interruption frequency (SAIFI) and interruption length (CAIDI)*"[35] and therefore considers "*that reducing or removing SAIFI from incentives may be appropriate*"[36]. We agree with this statement and consider that it holds true not only for reliability incentives, but also for quality standards.

11.6. Increased SAIFI is frequently the price that is paid for actions taken to mitigate SAIDI[37]. The key issue with SAIFI as a compliance measure, is that it drives a poor outcome for consumers, as distributors try to find an almost unachievable balance between interruption duration and frequency.

Separation of planned and unplanned outage standards

11.7. We support the separation of planned and unplanned outages for the purposes of the quality standards and agree that "*the integration of planned and unplanned interruptions into a single standard have the potential to create perverse incentives*"[38].

11.8. The Commission has, in our view, taken a pragmatic approach to incentivising distributors to prioritise planned work, which ultimately has a positive impact on reliability for consumers. The separation of planned outages from the combined quality standard, coupled with the more appropriate quality allowances, places a greater and more targeted emphasis on managing unplanned outages, and incentivises distributors to continue to prioritise planned work in years where that distributor experiences high levels of unplanned outages.

Regulatory period planned standard

11.9. We support an assessment of the planned outage standard once for the regulatory period. Adopting this approach affords distributors flexibility in their planned works from year to year.

Annual unplanned standard

11.10. We do not support a move to assessing compliance with the unplanned standard on an annual basis. The Commission acknowledged during the DPP2 reset that the "*quality*

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[35] Reasons Paper, paragraph M8

[36] Reasons Paper, paragraph M8

[37] As an example, many networks are unable to accept direct connection of generation and require relatively short outages to safely install and remove generators. While generation mitigates SAIDI impact under these circumstances, SAIFI is doubled.

[38] Reasons Paper, paragraph L15

standards employ the two-out-of-three rule because this allows for one-off poor performing years, which alone may not constitute an underlying material deterioration of reliability".[39] We agree with this view and consider that it remains relevant to DPP3, even with an increase to the standard deviation, which we support. In our view, the two-out-of-three rule should be maintained.

Planned standard set 200% above historical average

11.11. We support the new planned standard being set at 200% above the historical average. This is the first time that this compliance measure has been introduced and taking a cautious approach to setting the compliance limit is, in our view, warranted.

11.12. We do, however, harbour concerns with regard to the introduction of the concepts of "additional notice" and "intended interruptions", which we discuss further in paragraphs 12.5 to 12.9 below. While we acknowledge that the intention has been to introduce these mechanisms for the purposes of the quality incentive scheme, the fact that the formulas for the calculation of the SAIDI and SAIFI assessed values for planned interruptions, given in Schedule 3.1 of the Draft Determination, apply the 50% discount for the purposes of compliance with the quality standard, makes those concerns equally applicable here.

Extreme outage event standard

11.13. We do not oppose the introduction of a SAIDI extreme outage event standard. We acknowledge that the causes applicable to the extreme outage event standard are generally within a distributor's control and that these are a focus of good asset management practice.

Automatic reporting requirements for quality contraventions

11.14. As acknowledged above, we support automatic, enhanced reporting requirements for quality contraventions, since gaining a deeper understanding of reliability performance is a part of good asset management practice. We acknowledge that the Commission has addressed our concerns regarding a distributor's ability to include all required information in its annual compliance statement.

12 Reliability incentives

Revenue-linked incentives apply to planned and unplanned SAIDI

12.1. We support the removal of SAIFI from the reliability incentive scheme. We raised at paragraphs 11.4 to 11.6 above, that we believe that the rationale for removing SAIFI from the reliability incentive scheme applies equally to removing SAIFI from quality standard compliance.

Setting the incentive rates

12.2. We agree with the proposed shift from endogenously setting incentive rates to expressly setting the incentives rates applicable to each distributor. This change means that more reliable distributors are no longer more heavily penalised relative to others, and that the incentive scheme is more consistent.

12.3. Considering the removal of SAIFI from the incentive scheme, we accept the use of VoLL for setting the incentive rate, however, we remain unconvinced that a VoLL of $25,000 per megawatt hour is appropriate. No substantive evidence has been provided to support the adoption of this value, other than drawing comparisons to the VoLL adopted by the AER and Ofgem.

12.4. To clarify our comments in our submission on the Issues Paper,[40] our recent survey of Aurora consumers derived a weighted average estimated VoLL of $15,615 per megawatt hour,

[39] Commerce Commission (2014), Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main policy paper, 28 November 2014, paragraph 6.9, p33.

[40] Aurora Energy Limited. (2018). Submission – Commerce Commission: Default price-quality paths for electricity distribution businesses from 1 April 2020 – Issues Paper, 20 December 2018, paragraph 4.7.

which is significantly lower than the $25,000 per megawatt hour proposed, or the $20,000 per megawatt hour enshrined in the Electricity Industry Participation Code administered by the Electricity Authority.

Incentives for notification of planned interruptions

12.5. We accept that de-weighting of planned interruptions by 50% relative to unplanned interruptions will continue in DPP3, given the relaxing of the quality standards for planned interruptions.

12.6. However, we are concerned that the additional incentive that has been proposed to better incentivise distributors to notify consumers of planned interruptions, fails to consider the practicalities of undertaking planned outages and may encourage some distributors to prioritise SAIDI over safe work practices.

12.7. The additional incentive that has been proposed is two-fold:

- the incentive to provide *"additional notice"* (as defined in the Draft Determination) by distributors for planned interruptions; and
- the incentive to not cancel an interruption where additional notice was provided (an *"intended interruption"* (as defined in the Draft Determination)).

12.8. In order to qualify for further de-weighting of interruptions for which "additional notice" has been provided, it is necessary for:

- the interruption to not span more than four hours. We consider that in practical terms, four hours is too short a period for a planned interruption. This timeframe:
  - fails to consider switching that may need to occur either side of the works themselves (with switch locations frequently remote to the worksite). Once the necessary switching has been undertaken, this leaves a very tight window in which to undertake the works. The result is that pressure may inadvertently be placed on field staff to employ unsafe work practices, or push the boundaries of safe work practices, in order to carry out the works in the remaining time available. We do not consider that this risk is intended and that it could be avoided by a longer interruption span in the definition of *"additional notice"*; and
  - does not provide distributors with any incentive to consolidate work packages into one longer outage, which ultimately imposes less disruption on consumers than multiple shorter outages over a number of days or weeks.

  In our view, paragraph (a) of the definition of *"additional notice"* in the Draft Determination should be amended to read *"that Class B interruption must not span more than 8 hours"*; and
- information about the interruption to be provided to a *"notice group"* (as defined in the Draft Determination). While the draft decision requires notification to all electricity retailers affected by that interruption (which distributors are already doing in practice pursuant to their use-of-system agreements), it extends the obligation so that distributor are required to notify the 10 largest consumers affected by the interruption. In our view, this additional requirement is not practicable (how do you demonstrate compliance when the interruption affects only residential areas with homogenous connection characteristics?) and the obligation should be limited to notifying the affected retailers.

12.9. If an outage does meet the definition of "additional notice", yet does not occur, then the distributor will still incur the de-weighted SAIDI that would have been attributable to that outage. While we appreciate that the intention is to provide incentives to distributors to not over-notify planned interruptions, which when cancelled can lead to frustration on the part of consumers, the requirement may drive perverse and unintended consequences. We agree that there should be incentives placed on distributors to plan their work effectively; however, we disagree with SAIDI being incurred by a distributor for a notified planned interruption cancelled due to inclement weather or unsafe work conditions. In our view, by not providing an exception for these reasons, distributors may be unintentionally encouraged to undertake planned works in conditions where the outage would otherwise have been cancelled and, as with the proposed four-hour planned interruption constraint discussed above, unintentionally cause reasonable standards of safety to be compromised.

Limiting the revenue exposure

12.10. We support limiting the revenue exposure of distributors to 2%, given that the incentive rates have been expressly set.

13 Other measures of quality of service

13.1. We support the introduction of other measures of quality of service in information disclosure, before being adopted (if appropriate) into the DPP framework. We consider that this workstream should be undertaken as soon as possible, after the final decision for DPP3 has been released, so that changes can be implemented and supporting practices allowed to mature, before being considered for incorporation into compliance at the next DPP reset.