Orion

20 December 2018

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Dear Dane

Submission on EDB DPP3 Reset

Summary

1. Orion welcomes the opportunity to submit on the Commission's issues paper on default price-quality paths for electricity distribution businesses from 1 April 2020.
2. For DPP3, overall we support the use of the standard DPP process for Orion's reset, provided appropriate account is taken of qualitative information provided in our 2018 and 2019 AMPs.
3. The proposed, mainly quantitative, assessment methods for EDBs' capex and opex expenditure forecasts limit the important role of AMPs. In our transition from a CPP, our current and next ten-year AMP will significantly reduce any information asymmetry for the Commission and interested parties, and they are appropriate to consider in setting opex and capex allowances for our reset.
4. Our FY19 capex and opex expenditure actuals will not fully capture our forecast opex and capex expenditure for the FY21-FY25 reset period. Considerable change from customers, community and government is putting new demands on us – for example:

    - recruitment to address the need for new skills and capability
    - labour pressures and related rates movement
    - pending increases in FENZ levies

- growth/security of supply driven capex as a result of ongoing and significant customer connections in some parts of our network
- other opex programmes and capex projects in parallel with growth/security of supply driven capex
- expenditure to increase visibility, control and asset management of low voltage networks that will be increasingly used to support more two-way power flows with customers
- implementation of software and hardware to support asset management decision making, more automation and system control

5. We welcome the paper's intention to focus on incentives to influence EDB behaviour and we assert that it is timely for introduction of enhanced incentives for innovation, but the paper does not propose any specific incentives.

6. We support moving the a movement in capex incentive closer to the opex incentive, **provided** the scrutiny applied to capex expenditure gives appropriate weighting to EDBs' AMP forecasts and qualitative commentary in support of these forecasts.

7. For setting quality limits the reference period of the most recent 10 years, FY10 to FY19, is appropriate and we recommend no adjustment to our reference dataset. The historical dataset encompasses the capped impact of the physical environment our network resides in, our operational response and the benefit of our investment decisions. We see no perverse outcomes in treating our quality dataset the same as others in this reset.

8. We disagree with many of the underlying proposed changes to quality limits and incentives, given the current regime is in its infancy and has not been tested over time – and so further disaggregation, complexity and risk allocation is not appropriate yet. In particular we do not support:
    - a split of planned and unplanned outages, removing planned outages from the incentive scheme, and using a five year historical window or forecast window for planned outages
    - disaggregation of an imperfect measure such as SAIDI/SAIFI. It will drive additional cost from resource and systems required to deliver, report and audit it, for little benefit
    - a step change in the quality incentive/penalty from 1% to 5%. We note that the paper overlooks that an increased incentive is itself a source of recoverable cost that will contribute to potential price shock for consumers
    - a change to the cap and collar bands from one standard deviation to two standard deviations on the basis that this may result in material deterioration of quality performance

- the inclusion of other proposed measures of quality as part of the quality incentive. Extending these measures into the incentive scheme is premature.

9. A customer satisfaction survey using a consistent method across all EDBs would provide valuable high level information for stakeholders rather than in the first instance measuring customer service at the specific level of notification of planned interruptions and new connections.
10. We recommend the provision of scope for smoothing of step changes in transmission prices.
11. A revenue cap is intended to ensure that EDBs are not affected by fluctuations in chargeable quantities. The revenue cap should make specific allowance for adjustment (and reduction) to quantities to reflect situations where chargeable quantities cannot be applied, including where this occurs through retailer default or termination of a use of system agreement.
12. We do not support a guaranteed service level for DPP3 ahead of careful consideration of the details of such a mechanism and its treatment within the regulatory regime.
13. We do not support the inclusion of an energy losses incentive in the regulatory regime. Losses includes both technical and non-technical losses. EDBs have little or no control over non-technical losses. Technical losses are difficult to measure and other jurisdictions have already come to this conclusion.
14. Basic visibility of the LV system is a prerequisite to reporting accurately on power quality measures that impact customers and to provide the dynamic response required on a two-way distribution platform. Prescribed requirements to discuss the low voltage system in our AMPs is critical and we believe this would be beneficial to customers and other stakeholders.
15. Targeted investment by EDBs in the LV system will facilitate provision of accurate system performance data to inform real-time and future asset management decision making. Approving opex and capex expenditure for EDB monitoring, data analysis, and improvement of low voltage systems will benefit service quality and will identify phase imbalance which is a practical loss reduction measure.

General Comments

16. We appreciate the Commission's commentary on Orion's particular situation in coming off a CPP onto a DPP. We agree with the assertion that we can be treated on the same basis as others as long as this is workable, for the reasons stated in the issues paper[1], and subject to exceptions to process being by way of adjusted data set, if required, and appropriate consideration given to our 2018 and 2019 AMPs.
17. We support the ENA submission except where we make alternative comments in this submission.
18. In line with our feedback on the Commission's 9 November 2017 open letter we agree with the Commission's decision to make no changes to the length of the DPP regulatory period in this reset.
19. We support the move to address the inconsistency between the normalisation methodologies of reliability metrics between the DPP and information disclosure.
20. We note the balance the Commission must manage between focussing on the fundamentals[2] and the acknowledgement that technological developments mean potential for changing services, service delivery and business models for EDBs[3] . The issues paper does not appear, apart from through a potential increase in the capex incentive, to provide enhanced incentive for EDBs to innovate. While this should occur in a business focussed on sustainability and may be driven by changing customer and societal expectations the support of the regulatory regime to provide avenue for funding such initiatives is timely.
21. The Commission discusses clarifying the DPP reconsideration and amendment process by publishing guidance rather than creating rules in the IMs or DPP determination. We agree with this approach as it provides greater future flexibility while being transparent about expectations.

Expenditure forecasts and AMP

22. We note the Commission, in assessment of capex and opex expenditure forecasts, limits the role AMPs will have. This appears to be a departure from the direction the Commission was heading and the approach used for the gas reset. We appreciate this approach is logistically difficult given the number of non-exempt EDBs however we submit, for Orion in its transition from a CPP, that AMPs are a key public disclosure and planning document and an appropriate source of information for justification of capex and opex expenditure forecasts over and above a DPP3 baseline, that is necessary to maintain levels of safety, reliability and resilience our community tells us they want.

[1] points 5.20.1 to 5.20.3
[2] DPP issues paper point 3.11
[3] DPP issues paper point 3.12

23. The use of AMPs in the reset assessment process, where this would provide important context for forecasts, should be strengthened. AMPs are used by EDBs to share information about the context for capex and opex expenditure forecasts including, for example, the extent of their systems, assets and capability, along with regional growth and connection patterns. It is an important method by which we can break down the information asymmetry that would exist if we did not publish the AMP. We recommend that the Commission should consider the qualitative and quantitative information in the 2019 AMPs for opex and capex assessment, and not just quantitative schedules and historical information.
24. We consider provision of an expenditure delivery report[4] to provide accountability during the regulatory period to be beyond the requirements of a DPP and an unnecessary cost. Many EDBs can and do make use of their websites, annual reports and other publications to inform customers and stakeholders about their delivery progress.

Operating Expenditure

25. The Commission have indicated that they are proposing to use actual operating expenditure for the 2019 disclosure year as the base level of operating expenditure[5]. We support this and believe it is, subject to our comments below, an appropriate starting point for our particular circumstances having completed our substantial post-quake recovery in FY18, and coming off a CPP onto a DPP.
26. We refer the Commission to the ENA submission for further context on the changing environment for EDBs that influence the cost of running our businesses and possible methods to address these factors.
27. The Commission proposes a step and trend approach for operating expenditure. This appears to be somewhat of a "blunt instrument" as it omits the use of AMPs to justify any step changes Orion may be facing. We note the ENA submission suggests other ways to alleviate the "bluntness" of the step and trend approach. Examples of opex forecasts not captured in FY19 which may be excluded by a step and trend approach include:
    - FENZ levies: The newly established Fire and Emergency New Zealand is reviewing its levy approach. From 1 Jul 2021 (or 2020) the FENZ levy will be calculated in a completely different way than the current regime. Yet-to-be promulgated regulations will specify how FENZ's future levies will be calculated but early indications are that the levy base will be broadened from contracts of fire insurance to contracts insuring property against physical loss or damage. This will include insurances which are currently not subject to levy, unless exempted. The levy will be calculated on the "amount insured" in an insurance contract,

[4] DPP reset issues paper point B43
[5] DPP reset issues paper point A5

rather than the indemnity value of property or the fire sum insured if capped. EDBs can currently reduce their levies by capping their material damage cover limit for losses caused by fire. The availability of utilising this cap is being reviewed under the new (draft) regulations, and should this option be removed EDBs will likely face far higher FENZ levies. The amounts involved cannot be reliably calculated or estimated at this time because the regulations aren't yet promulgated. We submit that given this will impact all EDBs, potential uncertainty around timing for and quantity of step change in these levies, that they be appropriately and prudently considered as pass through costs for DPP3. The Marsh November 2018 newsletter provides a useful overview of the current position and uncertainties, and we provide this as an attachment to our submission.

- Labour costs: We note the Commission's concerns with large cost increase due to potential labour shortages within the industry and particular regions[6] . We have made, and will continue to make, a number of appointments and changes to our organisational structure and risk management provisions to better deliver on business and emerging market imperatives. Additional resources and provisions are needed for:
    - i. increased customer engagement. This includes the appointment of a GM Customer and Stakeholder, and a Sustainability Lead.
    - ii. greater knowledge and monitoring of our low voltage systems. This includes pending recruitment of positions to support better analytics and enhancement of our system control and GIS software platforms.
    - iii. increased efficiency. This includes additional field operators due to the expansion of our network and a programme scheduler.
    - iv. increased assurance. This includes the cost of additional audit programmes.
    - v. appropriate standby emergency services arrangements. This includes renegotiation of our emergency services contract with service providers. As a result, we anticipate an uplift in labour rates.

27. These costs are not reflected in our 2019 actuals and this will increase our opex expenditure in FY21. More detailed explanation will be available for the Commission in the 'supporting our business' section of our 2019 AMP.

[6] DPP issues paper point A49

28. The Commission tabled some options for determining network scale growth[7]. We agree with using regional information where it is reliably available for instance in the case of population growth to forecast ICP growth.
29. The Commission questioned the merits of using *historical* line length growth to forecast and/or acquiring forecast line length growth from EDBs via an information request under section 53ZD of the Act. We agree that historical line length growth is appropriate for forecasting in Orion's circumstances.
30. We support the approach of using forecast new connections disclosed in EDBs' 2019 asset management plans (AMPs) via Schedule 12c to forecast ICP growth.
31. The Commission has asked whether we agree that there is an inverse relationship between capital expenditure and operating expenditure attributable to asset replacement renewal[8]. We disagree with this statement. In particular accounting standards provide flexibility for replacement costs to be treated as capitalised or operating expenditure. There will be varying approaches by EDBs. In our particular circumstances the extensive capital expenditure required post-quake means that in order to prioritise resources operating expenditure has been deferred at times. Moving forward the high number of connections, while beginning to level off, has meant that in certain areas of our network the firm capacity of substations has reached a threshold indicating a requirement to address capacity. This will mean that capital expenditure from growth will continue into DPP3 in parallel with operating expenditure programmes of work.
32. The Commission has asked whether we agree that there is a positive relationship between vegetation management operating expenditure and overhead line length[9]. We agree at a simplistic level there is a relationship between vegetation management operating expenditure and overhead line length however this overlooks some practical complexities. These complexities include the prevalent types of trees and their growth rates, climatic conditions in any given year, the terrain, the level of traffic management required and the degree of cost recovery from customers.

Capital expenditure

33. We note the Commission's finding that there has been a trend in under delivery of capital expenditure[10] suggesting a persistent over-forecasting[11], but also notes the year-on-year volatility[12] of capex. We agree that capex is volatile and difficult to forecast. Capital expenditure is often driven by specific customer requirements

[7] DPP issues paper points A7 and A35
[8] DPP issues paper point A8.1
[9] DPP issues paper point A8.2
[10] DPP issues paper point B11
[11] DPP issues paper point B23
[12] DPP issues paper point B25

and the timing of capex investment can change in accordance with their needs. Specifically capex expenditure can "roll forward" as projects get postponed year-to-year and so can appear in consecutive AMPs scheduled in a different year.

34. Our AMP contains important commentary about coincident factors causing capex expenditure to increase over historical levels. An example being our forecast expenditure for a new substation to the north of Christchurch. The combination of customer plans for a new manufacturing plant coinciding with the cumulative effective of a number of years' growth in residential and commercial connections in the area mean measures are required to ensure we do not contravene our firm capacity and we continue to meet our security of supply standards. We are not seeing these aspects occurring in different timeframes (i.e. where less expenditure would be required or could occur in stages) rather these aspects are happening at the same time resulting in a step change in expenditure. Further, changes in customer behaviour are necessitating new expenditure on our LV systems to increase transparency of operational metrics and to inform potential future expenditure.
35. We strongly believe that AMPs are an important starting point for forward forecasts and explanations for expenditure. The supporting commentary contained in AMPs that explain the forecast demonstrates internal consistency[13] and coherence[14], and remains an appropriate scrutiny method. AMPs are a key disclosure requirement with considerable effort and resource being employed by EDBs to present capex and opex expenditure plans and justifications.
36. In general the distribution sector is moving into a capital intensive period and we support the use of cap (maintained at 120% and 200%) arrangements[15] described for network and non-network capex respectively.
37. We do not support the use of a uniform dollar scrutiny approach as the size of an EDB is important and this would lead to an inconsistent approach across EDBs.
38. The Commission discusses scrutiny of capital contributions[16] and indicates that in previous DPPs capital expenditure has been set as forecast expenditure on assets net of capital contributions with no scrutiny on the level of contributions forecast by suppliers. EDBs provide some history of capital contributions in their disclosure (Schedule 6a) however the forecast level of capital contributions is primarily customer driven so we can expect some level of volatility year-on-year. For example in 2018 Synlait made a decision to install a 6MW electric boiler.

[13] DPP issues paper point B53
[14] DPP issues paper point B58
[15] DPP issues paper points B6.3.1 and 6.3.2
[16] DPP issues paper point B74

39. Orion's capital contributions are primarily driven by customer connections and asset relocations. Post-quake FY16 was a peak year for customer connections with capital contributions from these contributing 40% of total capital contributions or 15% of gross customer connection capex. This compares to FY17 and FY18 where capital contributions from customer connections contributed only 19% of total capital contributions or around 10% of gross customer connection capex (this reflects a more BAU level). Moving into FY17 and FY18 asset relocations have contributed to between 70 and 80% of total capital contributions. In recent times capital contributions from asset relocations has contributed the greatest to volatility. We are currently going through a very high level of these with the major roading projects NZTA has underway – Western bypass, Northern Corridor. While our percentage recoveries might not change substantially the gross dollars should certainly decline in the coming years. In our recent experience our forecasts are normally slightly lower than what actually eventuates.

IRIS incentive

40. We support smoothing recoverable costs from incentives to avoid price shocks.
41. Currently the IRIS incentive rates for opex and capex are different. Overall it appears that the Commission favours an adjustment of the capex incentive (currently 15%) so that retention factors between opex (currently 34%) and capex are broadly similar[17]. The rationale provided for this is that it would support incentives for demand side management[18] and any negative impacts from increasing the retention factor for capex will be offset by higher capex scrutiny[19].
42. We support a movement in capex incentive closer to the opex incentive **provided** the scrutiny applied to capex expenditure gives appropriate weighting to EDB AMP forecasts and qualitative commentary in support of these forecasts. While this does increase the risk to EDBs, as capex expenditure will be under pressure this reset, it does provide incentive to seek alternative solutions not reliant on capital expenditure.

Quality – SAIDI/SAIFI

43. We agree the "current 'no material deterioration' standard remains appropriate"[20], and the basis the Commission sets out for establishing that, but caution on any drive to reduction in limits in perpetuity. This is a different outcome to EDBs maintaining the level of reliability delivered to customers in the past.[21] This may drive over-investment for very little incremental quality improvement especially for some EDBs already providing appropriate levels of reliability and who are meeting customer expectations.

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[17] DPP issues paper point E16
[18] DPP issues paper points X44, F19, F22
[19] DPP issues paper point E17
[20] DPP issues paper point 3.32.3
[21] DPP issues paper point 4.24

44. We support the continuation of a 50% weighting on planned outages. As the Commission points out planned outages, while being less inconvenient, are not without inconvenience. In addition the quantum of planned outages may increase in times of high investment.
45. We do not support splitting planned and unplanned outages, removing planned outages from the incentive scheme, and using a 5 year historical window or forecast window for planned outages. Planned outage work is important for the ongoing development of the network to meet customer demand and the maintenance, renewal and replacement of existing assets. The ability to re-programme planned work when unplanned events occur is an important tool in day-to-day risk management of the network. Using a forecast for planned outages would introduce increased risk for EDBs as scheduling planned work is a dynamic activity that is impacted by weather, road and land access, customer requirements, traffic management, equipment delays and service provider availability. On this basis we support the retention of the 10 year reference dataset including planned outages.
46. We support retaining the current 2/3 rule for breaches of the quality limit.
47. We support updating the reference period to the most recent 10 years- 2008/09 to 2018/19.
48. In our circumstances any extension of the period which would capture greater historical data i.e. before 2008/2009 would result in perverse outcomes for customers; the parameters of our network have changed significantly and use of historical data before 2008/2009 would be out of kilter with the network we now manage post the earthquakes. Meeting the limits set for us for FY17 and FY18 have been challenging in two very benign weather years even with improvement initiatives in play.
49. We submit that no adjustment to our reference dataset is needed to set our quality targets and limits. The historical dataset encompasses the capped impact of the physical environment our network resides in, our operational response and the benefit of our investment decisions. Orion customers consider reliability to be the core function of the electricity network and a survey of residential customers found 94% were satisfied with our performance in this area. Some EDBs have breached limits due to events which were wholly out of their control however these events are now credible events that could occur from a risk management perspective. We have no evidence of the Commission excluding particular events from datasets and we see no perverse outcomes from treating our quality dataset the same as others in this reset.

50. While the paper suggests that SAIDI is the bigger cause of penalties and SAIFI the bigger cause of rewards[22] our experience during the CPP is that SAIFI has been the most challenging parameter to manage in meeting our limits. For some EDBs SAIDI and SAIFI limits have been met by only the smallest of margins during DPP2.
51. We see a number of issues impacting on our ability to maintain quality limits. They are;
    - the introduction of the Health and Safety at Work Act has meant a review of safe working practices including live line procedures. During 2019 we will release new guidelines for live line work for our service providers. We estimate that if we 'turn off' live line work altogether this will impact our performance by an increase of SAIDI 25 +/-12, and SAIFI 0.1 +/-0.03 using the current regulatory methodology. Our high level analysis of live line work over the last four years indicates that the level of live line jobs is reasonably consistent % of total planned jobs however we have observed a slight decrease in the most recent twelve month period. We have provided further detail in our response to the 53ZD quality request notice.
    - severity of weather events. NIWA's climate change projections for New Zealand show that the frequency of extreme winds over this century is likely to increase in winter and decrease in summer especially for the Wellington region and the South Island.[23] The NIWA study also suggests that there will be a slow increase in serious events, i.e., less snow, but extreme wind speed and very wet days. This is not peculiar to New Zealand- the American Quadrennial Energy Review found that "Events with severe consequences are becoming more frequent and intense due to climate change, and these events have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States."[24]

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[22] DPP reset issues paper point C61

[23] Scenarios of Storminess and Regional Wind Extremes under Climate Change, https://www.niwa.co.nz/our-science/climate/information-and-resources/clivar/scenarios

[24] Transforming the Nation's Electricity Sector: The Second Instalment of the QER; January 2017 Chapter IV

- our own analysis confirms in our region, the average number of adverse event days that we can expect is 2.7 (based on six years of data FY13 – FY18). These events are made up of 7 wind storms, 2 snow storms (1 of which was capped in FY14 and traversed a 2 day period), 1 bird strike and 5 plant failures. If we remove plant failures and years with no weather events (FY17 and FY18) the average number of adverse event days (FY13-FY16) remains at 2.7. Our analysis suggests for our geographical area we can expect one major event (capped) in each 5 year period. Given our experience and NIWA projections we suggest that it is appropriate to retain the use of the 23rd highest daily unplanned SAIDI and SAIFI for the boundary values.
- more implementation of Outage Management Systems (OMS) to improve quality performance analysis and reporting may result in increases in reported SAIDI/SAIFI metrics. Some utilities have found that their SAIDI value increased after the installation of outage management systems.[25] This does not imply that reliability worsens for those utilities or that deliberate misreporting has occurred, rather, the introduction of technology has enhanced reliability recording.

52. The Commission suggests reporting of HV SAIDI and SAIFI at a disaggregated level including by regions, network types and customer types. Our view is that overly disaggregating an imperfect measure such as SAIDI/SAIFI is not warranted given the operational impacts on cost from resource and systems required to deliver and report the measure. A proportionate approach to disaggregation of SAIDI and SAIFI is required here. We feel a focus on future plans for monitoring our LV system is a more efficient customer focussed enabling strategy.
53. We disagree with the notion of quantifying lost load or lost delivery from interruptions as suggested in the paper[26]. We agree with the Commission's statement that accurately measuring lost electricity load or delivery is likely to be difficult. At any given time the lost electricity load from interruptions depends on the status of each individual ICP and the mix of ICPs at the time of the interruption. Any methodology would contain significant assumptions making the transparency of the information very opaque and potentially misleading. In our experience customers are more concerned with less granular aspects of an interruption- the fact power has gone off and how long it will be until it is restored.
54. When EDBs contravene limits we think it appropriate and helpful to EDBs and the Commission's investigation process for a quality report with predetermined requirements as described in the issues paper[27].

[25] "Power Distribution System Reliability: Practical Methods and Applications" Ali Chowdry and Don Koval.
[26] DPP issues paper point C121
[27] DPP issues paper point C51

55. A new requirement to disclose up to 10 of our most major events during the disclosure year is suggested[28]. We support this suggestion because we see benefits in more transparency about the impact of major events and their frequency. This may inform quantitatively the level at which events should be capped.

Quality incentive

56. Overall, Orion remains unsure of its quality limits going forward in a post CPP environment. As such it is difficult to support changes to the incentive scheme.
57. The Commission has tabled the idea of increasing the quality incentive at risk from 1% of maximum allowable revenue (MAR) to 5% of maximum allowable revenue. To put this in context, for Orion in FY19, this would be a change from $1.8m at risk/reward to $9m at risk/reward. This would constitute a significant step change. We do not support a step change like this in an environment of increasing capital investment i.e. more planned work (our planned work is currently 18% of SAIDI and 6% of SAIFI), increasing weather events and a changing focus to LV systems. Importantly the reward or penalty from DPP3 is realised in DPP4 and should also be considered in the context of price shock for customers via recoverable costs. The current regime is in its infancy and has not been tested over time – and so further disaggregation, complexity and risk allocation is not appropriate.
58. The Commission has tabled the idea of changing the cap and collar bands from 1 standard deviation to 2 standard deviations. We are unsure how closely this suggestion is linked to the suggestion for an uplift in quality incentive to 5% of MAR. In principal we would not support a move to 2 standard deviations on the basis that this may result in material deterioration. We prefer focus on setting of targets that are realistically achievable.
59. We do not support the inclusion of the other measures of quality (discussed below) as part of the quality incentive.
60. We support the current approach to caps and collars. We do not support an asymmetric approach as the uncapped component of adverse events already creates an underlying level of asymmetry.

Other measures of quality of service

61. We support the concept of providing reporting on notification of planned interruptions and new connections as measures customers' value. However these metrics will need to be well defined. Currently notification of planned outages is often via Retailers using Electricity Authority approved information exchange protocols. We note here that the Electricity Authority is looking to standardise this process so that planned outage notifications using exchange protocols (EIEP5A) would be subject to centralised processing via the electricity registry. This change should support more consistent notification of customers.

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[28] DPP issues paper point C112

62. Customer connections can vary in size and complexity (technical and the number of parties involved) therefore the time from application to approval will naturally be different. EDBs employ a number of different business models for connection and installation processes from all-in-house to 3rd party contracts. Stages of the process between application and connection may be easier to control and measure such as (a) the time between a connection application and its approval or (b) the time to connect from the completion of all necessary Council, communications, other approvals and notifications required to carry out enlivenment (as is provided for in our existing Service Delivery Agreement[29] clause E3).
63. Extending the use of these two measures (connections and planned notification) into the incentive scheme is premature. We believe it is a more appropriate evolution to allow time for new information disclosure processes and reporting to coalesce before incentivising.
64. A customer satisfaction survey using a consistent method across all EDBs would provide valuable high level information for stakeholders rather than in the first instance measuring customer service at the specific level of notification of planned interruptions and new connections.

Revenue cap and price shock

65. We support the Commission's position on not implementing a 'limit on forecast allowable revenue as a function of demand.'
66. While the Commission discusses the potential sources of price shock it does not define what level of change constitutes price shock and this would be useful. We are also unsure whether the concern is price shock or bill shock? Prices and quantities can act together to result in a net zero effect on the bill. We doubt that underlying factors such as negative growth/depopulation are likely to occur at such a rate as to constitute 'shock', although this could add to the effects of the other sources of variation.
67. The Commission discusses recoverable costs as a potential source of price shock in DPP3. This is due to recoverable costs applying in DPP3 that do not apply in DPP2. The Commission discusses IRIS recoverable costs and transmission pricing methodology as sources. DPP2 is the first regulatory period in which IRIS applies and the true impact of this incentive will only become apparent at the end of DPP2. The Commission overlooks the quality incentive as another potential recoverable cost that may be a source of price shock. This would be escalated in DPP4 if an increase from 1% maximum allowable revenue to 5% occurred in DPP3. Once again the true impact of this incentive will only become apparent at the end of DPP2.

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[29] Orion's Service Delivery Agreement- http://www.oriongroup.co.nz/customers/about-electricity/industry-structure/retailer-agreements

68. At present we are required to immediately pass through transmission costs and are unable to deliberately carry these forward. In our experience year-on-year changes in transmission costs can be up to +/-15% ($10m) and we submit that there should be more scope for smoothing these sorts of cost movements over multiple years (and possibly beyond regulatory periods).
69. While many of these recoverable costs have the potential to off-set each other, an option to smooth the impact of recoverable costs would be appreciated, prudent and in the best interests of consumers.
70. In our experience we confirm that the revenue from irrigation demand can be volatile from year to year depending on whether it is a wet or dry summer. We currently recover around half of our irrigation revenue from fixed prices. We do not seek to 'wash-up' based on this volatility and we would not encourage such an approach at customer category level as the administrative cost would outweigh any benefit. We will not alter our approach due to a revenue cap form of control except to progress any changes from a move to more cost reflective pricing which may serve to lessen the volatility effect of irrigation demand.
71. A revenue cap is intended to ensure that EDBs are not affected by fluctuations in chargeable quantities. One growing area of concern is the situation where revenue is lost due to retailer default- effectively the chargeable quantities are unable to be applied. The number of retailers has increased significantly over the last period and many of the small retailers do not carry the natural hedge and asset backing of generation. The prudential security EDBs can apply to retailer contractual relationships is significantly limited under the Code. We submit that the revenue cap should make specific allowance for adjustment (and reduction) to quantities to reflect situations where chargeable quantities cannot be applied, including where this occurs through retailer default or termination of a use of system agreement.

Customers

72. The Commission has highlighted three aspects as being important to their approach to DPP reset in the context of the electricity price review. This includes that the effectiveness of incentives in influencing EDB behaviour and service levels (reliability and resilience) reflect levels that consumers want and the NZ economy requires. Orion has been engaging with customers via its customer advisory panel, workshops of rural, residential and business customers, and through surveys to expand our understanding of what our customers' expectations are of us. We find that face-to-face approaches provide for a richer exchange where both parties can learn from each other. A key element of this mutual relationship is the degree to which our customers trust us. We are currently exploring this aspect with our customers to better understand what elements of our service build trust.

73. The Commission has indicated it will use the process used in Powerco's and Wellington Electricity's CPPs as a starting point in communicating customer impact. We assume the process referred to is the calculation method provided in attachment B, to the Commission's open letter in July 2018, requesting feedback on CPP processes. The Commission's Powerco CPP decision[30] noted the limitations of this approach, that it is only 'an average' and that it depends on how an EDB allocates its total revenue requirement and how retailers structure their prices. This approach was applied to Powerco moving from a DPP to a CPP. We believe it will remain important to highlight these qualifications and we are interested in whether the Commission considers the formula appropriate for year on year movements in the event that volumes change.

Guaranteed Service Levels (GSL)

74. Orion does not support the introduction of a guaranteed service level.
75. The development of such a scheme requires careful consideration and time to develop. Contemplating development of a GSL so close to the final decision date for DPP3 risks compromising the quality of the scheme.
76. We support further consideration of the construct for a GSL over the next period in conjunction with the Commission for further consultation at DPP4.

Power quality

77. We agree that understanding power quality measures becomes more important as networks become platforms for two-way flows. Basic visibility of the LV system is a prerequisite to reporting accurately and dynamically on power quality measures. This is succinctly discussed in Essential Energy's submission on the Open Energy Networks consultation paper in Australia.[31] Targeted investment by EDBs in the LV system will facilitate provision of accurate system performance data to inform real-time and future asset management decision making. This capability build is in its early stages so we do not support inclusion of a voltage stability disclosure in DPP3.

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[30] Powerco CPP decision point 21 page 17

[31] https://www.energynetworks.com.au/sites/default/files/essential_energy.pdf

78. Orion has forecast capex expenditure, in its 2019 AMP, to install monitoring and sensing equipment at selected locations on its LV network to improve our visibility of LV operational metrics. We have also begun discussions with retailers and metering equipment providers about paid access to metering data. These two initiatives will together provide access to voltage information at a suitable resolution, selected distribution transformers and at end consumer, on the LV system. We believe this is a cost effective means of obtaining data with good coverage and oversight that could be used to report on voltage stability among other metrics. However it may take further time to put these arrangements in place and as a consequence report on voltage stability in a reliable manner. Further voltage stability is already covered by technical network regulations.

Incentive on energy losses

79. We do not support the inclusion of an energy losses incentive in the regulatory regime.
80. The currently disclosed loss ratio includes both technical and non-technical losses. EDBs have little or no control over non-technical losses. This reduces our influence only to technical losses. In Great Britain a revenue incentive was found lacking as a suitable mechanism for loss reduction since losses were more difficult to measure than first envisaged[32]. Disclosed loss ratios include non-technical losses and our currently disclosed loss ratio is low at 4.1%. If an EDB invests solely to reduce losses, at the exclusion of other important considerations, the impact of that investment on the loss ratio could be countered by an issue with non-technical losses. This would negate the investment and penalise the EDB through the incentive despite taking measures to respond as intended to the incentive.
81. As stated in our 2013 submission to the Electricity Authority[33]. We agree that a reduction in technical losses improves productive efficiency: any given consumer demand will be met at lower overall cost. Over time this will lead to dynamic efficiency gains as less distribution, transmission and generation is built. We believe we are already making appropriate analysis and optimisation of technical losses in our investment decision-making. For example Orion's transformer selection criteria incorporates a calculation of the value of losses over the transformer's lifecycle even though Orion does not pay for losses.
82. When EDBs take on Transpower spur assets as a result of this 'change in boundary' there will be a small increase in losses that would be penalised by a losses incentive despite the other operational and economic benefits that resulted in the transfer occurring.

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[32] Brattle Group on behalf of ENA- incentive mechanisms in regulation of electricity distribution innovation and evolving business models- October 2018 page 56
[33] http://www.oriongroup.co.nz/assets/Company/Electricity-Authority-submissions-archive/Submission-on-loss-factors-Apr-2013.pdf

83. For us to reduce technical losses further than current levels would result in only incremental benefit in loss ratio for significant additional capex expenditure. For instance reducing resistance will require expenditure on increasing conductor size however this often leads to the need to install stronger poles and shorten span lengths. We already have plans to install a Statcom for voltage regulation at a rural zone substation in 2019. To some extent a losses incentive could compete with the incentive to not overbuild.
84. Orion already uses GXP pricing and applies peak demand pricing methodologies which provide price signals for demand reduction to retailers and customers at times when losses are highest.
85. To apply a cap and collar approach in an asymmetric manner would require defining a loss ratio % that is ‘acceptable’. What is acceptable is underpinned by the type of network an EDB operates and technical constraints of equipment. Networks with substantially urban distribution systems can expect loss ratios at around half the level of networks with substantially rural distribution systems. Customer density is a factor here which impacts on the number of transformers in a system, a significant contributor to losses. More technically efficient transformers are often more expensive to purchase.
86. As an example we consider the Commission would be better to focus on supporting EDB analysis, monitoring and expenditure on low voltage systems which could include identification of phase imbalance. Where phase imbalance exists as LV load grows organically and through the uptake of emerging technology by customers, this will, if not addressed, bring forward the requirement for reinforcement. The potential for capacity release would defer LV asset investment and this would be of greater benefit to consumers especially as the role of LV becomes more important i.e. make better use of what is already there.
87. Disclosure requirements for AMPs that include highlighting projects that would reduce distribution system losses and the related expenditure requirements would be beneficial. This would also provide information about the use of emerging technologies and provide signals to potential third party solution providers.

Indices/escalators/econometric approach

88. While the Commission has indicated it is not prioritising the use of detailed EDB or region-specific tailoring of forecasts and other mechanisms, for this reset, we believe this can be important for some regions and will become more important as emerging technology impacts regional economies on different timeframes and in different ways.

89. There are currently skill shortages in information technology, engineering, contract management, project management and in-field service occupations. In parallel there is skill transfer occurring between EDBs that is only partly driven by the extent of work programmes in areas with CPPs or pending CPPs. Labour costs are also being driven up by the increase in union activity in general. The recruitment and retention environment is more challenging that it has been for a decade. There are flow on effects from recruitment for productivity and operating costs. The skill shortages are also meaning that there is a necessity and urgency around a renewed focus on 'growing' in house resource through trainees, and to manage succession planning. We submit that local indices/econometric measures are better than national ones where these can be reliably sourced and applied.
90. We support the ENA submission on matters of indices/escalators and econometric values subject to specific points in our submission.

Other matters

91. The Commission has indicated that systems should be in place to record LV outages and MAIFI. The Commission goes so far as to state that not having systems in place now should not be a barrier for implementing systems to record these for disclosure[34] . Often systems are not available because up until recently the cost to install monitoring equipment, record LV in GIS or network management systems and resource LV outage tracking outweighed the benefits to customers. However there are now other reasons why more transparency of the LV system is more important.
92. Customers are beginning to make new choices about electricity use and production that will mean the LV network will have a greater role to play in service delivery and network flow management. The Commission needs to recognise that in order to be in a better position to collect and report data reliably, EDBs will need time to invest and put in place these new systems and resources. We are considering these aspects now however this will result in step changes in operating and capital expenditure in the short term but efficiencies and benefits for customers in the long term. Consequently we do not support the addition of MAIFI and LV outages as part of information disclosure for DPP3. We do however see prescribed requirements to discuss the low voltage system in our AMPs as critical and believe this will be of benefit to customers and other stakeholders.

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[34] DPP issues paper point C117

93. The Commission discusses the likelihood of more than 5 CPP applications in one year[35] suggesting that given the pre-CPP engagement process this would not be expected and that it would be known well in advance. The Commission may have overlooked some particular and possible scenarios for example multiple CPP applications following an Alpine Fault event or Tongoriro/Ruapehu eruption.

Concluding remarks

Thank you for the opportunity to provide this submission. We do not consider that any part of this submission is confidential. If you have any questions please contact Dayle Parris (Regulatory Manager), DDI 03 363 9874, email dayle.parris@oriongroup.co.nz.

Yours sincerely

Rob Jamieson
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[35] DPP issues paper point 5.4