Orion

18 July 2019

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Dear Dane

Submission on EDB DPP3 Reset- Draft Decision (the Paper)

Introduction

1. Orion welcomes the opportunity to submit on the Draft Decision on default price-quality paths for electricity distribution businesses from 1 April 2020.
2. We support the ENA submission except where we make alternative comments in this submission.
3. It is clear from the Paper that the Commission has put considerable thought into the regime for DPP3.
4. We continue to support the Commission's use of the standard DPP process for Orion's reset in our transition from a CPP.

Summary

5. In principle:

   (a) the outcome of the opex assessment approach, in particular, fails to appropriately recognise the increasing and incremental on-going cost pressures on EDBs which compromises our ability to adjust for uncertainty and change.

(b) the capex assessment processes for DPP3, provided the base year adjustments proposed for final decision are made and subject to the more detailed comments in the body of our submission, are an improvement on DPP2 however we suggest some refinements to ensure the full extent of EDB capex activity is recognised.

(c) the Paper retains the use of SAIDI and SAIFI, for quality, however the underlying principle of no material deterioration is not fully maintained by the proposed changes. The Paper does present some impractical and sometimes complex changes to the quality regime. This does create uncertainty around the application, risks and potential outcomes for customers from the new approaches.

(d) the Paper introduces a new innovation allowance and major connection reopener. We support these as enhancements for DPP3 however we offer suggestions for refinement to better realise their benefit.

6. A key observation is, we see our role in the community as much broader than SAIDI and SAIFI, although reliability is fundamental. Continued focus on SAIDI and SAIFI, with increased compliance and reporting on this one service attribute, puts at risk the long term interests of customers more broadly. This is because it distracts resources away from other attributes that the Commission considers critical to good asset management such as asset criticality, resilience, sustainability, and planning for future networks.
7. Our submission proposes a number of suggested refinements to the Paper to ensure outcomes better reflect EDB operating environments, can be applied in practice and overall are in the long term interests of consumers.

Opex Expenditure

8. We support the Paper's decision to consider FENZ levies as a recoverable cost for DPP3 given the uncertainty surrounding the review of levies as part of the newly established Fire and Emergency New Zealand.

Step changes and inflators used not entirely reflective of EDB operating environment

9. The outcome from the base, step and trend approach results in a lower opex allowance than we forecast. However, the Paper comments that most distributors are overspending their DPP2 opex allowances on average[1]. There appears to be an inherent mismatch here between allowances and what EDBs need to meet its community need.
10. EDBs provided the Commission with submissions to the DPP3 issues paper that indicate operational expenditure is not always related to the scale factors (circuit line length and connections) or historical

[1] DPP draft decision E44

performance. Examples of these cost increases include vegetation management[2], the emerging need for feasibility studies and trials, development of distribution control and GIS layers for LV network, implementation of cost reflective pricing[3], strategic repositioning to support decarbonisation and societal expectations around sustainability, the need for increased control and automation (involving information management expenditure) to support dynamic control of more complex network systems, and increasing regulatory compliance reporting and audit.

11. We submit that the Commission is not responsive to valid EDB commentary about increasing requirements and responsibilities impacting operating costs for us. Lower opex expenditure allowances than forecast may compromise our ability to provide network services at the levels our customers tell us they want. It is important for quality of service that EDBs are able to carry out the ongoing asset management requirements that maintain our existing assets, and that we can response to broader societal change driven by customers and the government.
12. Our community and customer feedback is that we should be 'future ready'. On page 78 of our 2019 AMP we share our customers' views on preparation for the future. 79% of residential customers surveyed think it is important or very important for Orion to be a leader of technology, anticipate customer needs, innovate, and proactively prepare for new technologies.
13. Update of the draft decision to use FY19 as a base year does help to reflect EDBs current operating environment however there remains a risk that expenditure needs, to prepare for new technologies and the way our customers may use our network in the future, will arise during DPP3 that were not anticipated.
14. As an emerging example, the Climate Change Response (Zero Carbon) Amendment Bill recently open for submissions signals potential impacts for our operating environment that will drive opex costs into our businesses. Specifically;

    "An adaptation information-gathering power will enable the Minister to require central government organisations, local government organisations, and "lifeline utility providers" to provide climate change adaptation information. The information will include the organisations' assessments of the risks climate change poses to their functions, the organisations' proposals and policies for adapting to climate change, and their progress towards implementing the proposals and policies."

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[2] As a result of liability decisions around Consumer Guarantees Act (UDL) and trees, greater weighting of regulation on this as a requirement to demonstrate 'good industry practice' (recent breach investigation reports), to address reliability, and increasing service delivery rates.

[3] Such as engagement with stakeholders and customers, collaboration with other EDBs, operational changes to billing platforms.

15. As a further example, the Interim Climate Change Committee report[4], action on agricultural emissions and accelerated electrification, supports using electricity to reduce transport and process heat emissions. The report states that:

    "The Committee recommends that regulators be required to take emissions reductions objectives into account, as well as facilitating and enabling new generation and both market and distribution innovation."

    We submit that this is further evidence of policy change that will drive further increases in EDB opex costs that need to be accommodated in DPP3.
16. We submit that the Commission must address these issues by including a trend factor allowance to accommodate these pressures. The only allowance in the Commission's model for non-scale related drivers of opex is the partial productivity factor. We submit that, for DPP3, a negative partial productivity factor should be applied, rather than the 0% proposed and we support the ENA's submission and supporting paper from NERA on this.
17. We would welcome the chance, for DPP4, to discuss greater use of AMP forecasts to assess allowable opex expenditure.
18. The Paper clarifies that, on a forward-looking basis, fines and penalties do not qualify as opex for DPP purposes.[5] We seek clarification that there will be no impact on past profit. On this we support the ENA submission on EDB and Transpower IM amendments.

Capex Expenditure

19. We agree with the approach of using distributor AMPs as a starting point for forward forecasts and explanations for capex expenditure. The supporting commentary contained in AMPs that explain the forecast demonstrates internal consistency[6] and coherence[7], and remains an appropriate scrutiny method. AMPs are a key disclosure requirement with considerable effort and resource employed by EDBs to present capex and opex expenditure plans and justifications.
20. We also submit that even greater use could be made of the qualitative and quantitative information in an AMP where an expenditure category fails the gate tests. While we appreciate and support the default price-

[4] Interim Climate Change Committee, action on agricultural emissions and accelerated electrification, summary reports and recommendations, page 11, released 16 July 2019
[5] DPP draft decision A61
[6] DPP issues paper point B53
[7] DPP issues paper point B58

quality path being a low cost approach there is a balance required. Taking an approach that is too high level may not reflect an accurate picture of capex required as important information may be omitted.

21. Overall we endorse the general approach to capex assessment of allowances and we provide some suggestions for refinement below.

Gate 4- AMPs key for system growth assessment

22. The Paper's high level assessment process for system growth has determined that Orion's system growth forecast is reasonable for DPP3 and should be allowed. We have some observations on the assessment approach that the Commission could consider.
23. Schedule 12b provides only information on existing substations and omits information on any new planned GXPs or zone substations. This is an area where the AMP can provide rich information. For instance, Table 1.1 of our 2019 AMP details plans for a new Belfast zone substation ($37.943m) and a new Norwood GXP ($28.937m) within the DPP3 regulatory period. Diagrammatic representation of these development proposals can be seen in Figure 6.6.3 page 163 and Figure 6.6.6 page 167 of our 2019 AMP.
24. In addition, the expenditure reviewed (Schedule 6a(iv) of information disclosure, zone substations line) will likely underestimate actual expenditure because zone substation or GXP expenditure, especially for greenfield builds, will invariably include system growth costs that relate to interconnecting cables and switchgear.
25. We reinforce the need to review AMPs where initial gate thresholds fail. Consultation with EDBs, in this instance, can provide direction to important information contained in the EDB's AMP.

Gate 5- Asset replacement and renewal.

26. The Paper proposes an assessment of asset replacement and renewal expenditure against RAB depreciation expense. The Paper proposes that the comparisons indicate that EDB's are underinvesting:

    "…Figure B8 highlights a potentially concerning trend of distributors' under-investing in maintaining their assets..."[8]

    However the Paper notes that this method of comparison is imperfect[9].

27. This *imperfect* caveat is important, the assessment has shortcomings for our circumstances that mean a conclusion of underinvestment by Orion is inappropriate, including:

[8] DPP draft decision B154
[9] DPP draft decision B153

(a) the comparison relies on all EDBs applying their respective cost allocations consistently. For example, 100% of our expenditure goes to our primary driver category. If a project's primary driver is system growth, we allocate 100% of the cost of the project to system growth, even if there are significant elements of asset replacement and renewal

(b) for us, this means that categories of system growth, service interruptions and emergencies, consumer connection, and asset relocations capex are likely to include elements of other cost categories including asset replacement and renewal, but these aren't represented by the assessment approach.

(c) for us, this means our post-quake expenditure on asset replacement and renewal is not recognised. This may be true for other EDBs that are experiencing high demand growth.

(d) the assessment is for network expenditure but the comparison is with total depreciation expense, including for non-network assets.

28. We submit that the Commission could consider refining of its gating process for asset replacement and renewal for the final DPP3 decision to better reflect the underlying replacement and renewal expenditure activity of EDBs.

Efficiency (IRIS) incentive

29. We support the Paper's equal treatment of capex and opex expenditure under the IRIS mechanism subject to appropriate capex and opex allowances.

Innovation and uncertainty

30. The inclusion of an innovation allowance is a positive enhancement for DPP3 however the quantum of the available allowance at 0.1% of revenue[10] (excluding pass-through and recoverable costs) is less encouraging.

31. The Minister of Energy has previously challenged the energy sector as a whole for its lack of investment in research and development above her current estimate of an $8m spend[11]. The new allowance signals the regulator's support for innovation but the quantum is disproportionate to the challenge put to the sector by the government and one we believe we are facing.

32. The Interim Climate Change Committee report[12], action on agricultural emissions and accelerated electrification, supports using electricity to reduce transport and process heat emissions. The report recommends that a responsive regulatory system:

[10] Approximately $5m in total

[11] Energy news 13 March 2018; https://www.energynews.co.nz/news-story/innovation/36891/energy-sector-warned-complacency-face-disruptive-tech

[12] Interim Climate Change Committee, action on agricultural emissions and accelerated electrification, summary reports and recommendations, page 13, released 16 July 2019

"Enables distributors and retailers to innovate and adapt to increasing levels of consumer-based technology."

33. We support the ENA submission suggesting a counter proposal for a pooled industry fund administered via ENA. This approach will encourage collaboration and sharing of learnings between EDBs, and avoid duplication of effort and expenditure on similar projects. This approach may also support industry work on the Network Transformation Roadmap.

Major connection reopener

34. The introduction of an unforeseen major connection reopener is an important enhancement for DPP3 under a revenue cap. Orion's role is to support our community's aspirations for a liveable region, with strong connected communities, a healthy environment and a prosperous economy. A major connection reopener enhances customer choice to make investment decisions in the near term, within a regulatory period, especially where these support longer term outcomes of economic growth and the nation's sustainability and climate change objectives. The reopener ensures local business and Orion can work together for the long term benefit of consumers and New Zealand.
35. We do however suggest some refinements on the form of the reopener to ensure the benefit is realised. In the following points we discuss the workability of the threshold set for the reopener, the approval process, and the criteria for projects.
36. For Orion, the >5% threshold set for the reopener will be too high to capture the likely expenditure levels and projects the reopener should accommodate (in the case of Orion this threshold equates to approximately $8.4m in FY21). We cannot see a circumstance where we meet that threshold. For example, our most recent significant customer driven project was work to accommodate a conversion to an electric boiler. Excluding capital contributions this project cost approximately $2.4m. It is important that the regime captures significant projects like this.
37. We suggest that the >5% criteria[13]:

    (a) for an **unforeseeable** major connection project, be replaced with "the total value of the assets forecast to be commissioned is at least $1.0m or greater for the disclosure year(s) in which the assets for the project or programme is forecast to be commissioned." This is likely to be more appropriate in all network areas.

    (b) for a **foreseeable** major connection project, be replaced with "the total value of the assets now forecast to be commissioned is at least $1.0m or greater for the disclosure year(s) than the amount of the expenditure

[13] Draft electricity distribution services input methodologies amendments determination 2019 clause 4.5.5A(f) and 4.5.5B(e)

which was originally forecast for that project or programme for the disclosure year(s) within the current DPP regulatory period." This is likely to be more appropriate in all network areas.

38. The approval process, as it stands, is not compatible with the competitive environment in which our major customers operate. Often with short notice and minimal delay we must provide a solution or options upon which the customer determines whether they will go ahead. Being unclear on whether a project is accepted under the reopener provision is unhelpful, for both us and a customer, and could result in perverse outcomes.
39. An alternative simple and effective approach could be, where we can show that an upgrade reaches the suggested trigger, and the customer can verify the additional annual revenue that it pays to an EDB in relation to that upgrade or new connection, would be to allow the distributor to retain that revenue (over and above the annual revenue allowance) through until the next reset. Alongside this, it would be appropriate to carve out the capex and any identifiable opex from the Incremental Rolling Incentive Scheme (IRIS).
40. On criteria the Paper proposes, we note that a customer project could be conceivably foreseen but, based on the EDBs prudent judgement, not forecast due to the timing of the customer request in relation to AMP expenditure forecast cycles, the uncertainty around the project, or the uncertainty around the project cost (it will take time to build up a realistic forecast). In the current reopener wording this scenario is not accounted for and we suggest it should be because it will ensure greater accuracy of timing and cost for the project in question.
41. We note also, that while a major connection project may have been signalled in an EDB's expenditure forecast, due to the nature of the DPP assessment process, not all of the expenditure may be allowed as part of the capex expenditure. This means that if the project does eventuate as programmed in the forecast the EDB shareholder may still be left funding the balance of the project cost. We appreciate that the Commission is looking to accommodate the situation, where project costs are greater than anticipated, by application for a reopener.[14]
42. We seek clarification from the Commission on the anticipated timeframes to process reopeners when sought by EDBs. As previously discussed, in recent DPP3 workshops, customers often request major connection upgrades with minimal lead time relative to their desired project completion date.
43. To provide greater flexibility to modify the approach to meet changing needs over time, we submit that the criteria, framework and allowance for major connection projects should be moved from the IM

[14] DPP3 draft decision G8

Determination to the DPP Determination. The IM Determination can simply specify that the Commission may make an allowance for such projects within its DPP and CPP Determinations.

Revenue path

44. We support the Paper's proposal to retain the regulatory period at 5 years. As we have recently carried out a debt refinancing exercise this will support certainty for our debt funders, reduce credit risk, support longer term planning and lessen administrative overhead. Retention of a 5 year regulatory period is also consistent with the IRIS incentive mechanism.
45. The Paper indicates that increased opex expenditure as a result of the expected review of the Electricity (hazards from trees) Regulations could be applied for as a price path reopener. Given the uncertainty around outcomes from this review the ability to reopen is positive.
46. We support applying an NPV neutral 10% limit on the annual increase in forecast revenue from prices as this will minimise the potential for price shock for customers.

Quality standards

47. Overall the Draft Decision is looking to introduce a number of changes to the quality regime that reflect recommendations from the ENA's quality submission on the DPP3 issues paper. The direction taken however is somewhat different, the changes are complex, and we are concerned that they may not translate to better customer outcomes. Successful measures should report on material deterioration rather than one off or unusual events. We discuss this further in the following points.
48. The quality changes proposed will result in greater workload and cost for EDBs from data capture and processing. Any opex expenditure to implement quality changes, signalled through the draft decision, are not captured in the base year (FY19 for final decision) opex forecasts and will not be fully compensated for due to IRIS impacts.
49. The Commission recently reminded EDBs of their focus on asset criticality, sufficiency of investment and resilience[15]. A continued focus and increased compliance on SAIDI and SAIFI as the only measure of service could divert EDB resource away from the very service attributes the Commission considers key to good asset management practice.

[15] Commission stakeholder open letter 14 June 2019 and open letter on priorities November 2017

Reliability reference periods and disaggregation

50. We note that the Paper states that a 10 year reference period is appropriate[16] and we support this for unplanned outages. This reflects the recent operating environment of EDBs, and includes the frequency and variability of longer weather cycles over a reasonable time period.
51. We submit that the use of the most recent five year historical dataset for planned outages is necessary to reflect the uplift in planned work signalled by expenditure forecasts, and captured by the allowed revenue, that is expected to be delivered during DPP3. This is not reflected in the earlier years of a ten year historical dataset.
52. We submit in agreement with the ENA submission, that the anticipated level of planned work activity from increased asset replacement and renewal is not fully reflected even in a five year historical dataset. As an example, we have signalled in Section 7.5.5 of our 2019 AMP a steady increase in our 11kV overhead pole replacement over the next five years.
53. We agree with the decision to make no explicit changes to reliability by disaggregation by region or customer type. Further disaggregation of an imperfect measure such as SAIDI/SAIFI will drive additional cost from resource and systems required to deliver, report and audit it, for little benefit.

Quality standard breach

54. The Paper sets out three situations where an EDB can breach quality standards. These are the planned SAIDI 5 year limit, the unplanned SAIDI annual cap and the unplanned SAIDI extreme event limit. In DPP2, a breach occurs only when contravening SAIDI and SAIFI (combined planned and unplanned) quality limits in two-out-of-three years. At a high level there appears to be greater possibility during DPP3 of attracting pecuniary penalty under Section 87[17] of the Commerce Act.
55. The Paper implies that the result of assessment of unplanned outages separately, application of a 1.5 standard deviation, a rolling 3 hour normalisation and movement to an annual breach test is risk neutral. We don’t agree.
56. Following the release of the reliability models, the risk of breach due to a significant weather event, which doesn’t reflect material deterioration, is highly likely within a five year regulatory period. The three hour

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[16] DPP3 draft decision J41

[17] Commerce Act 1986 Section 87(3), the amount of pecuniary penalty must not, in respect of each act or omission, exceed $500,000 in the case of an individual, or $5,000,000 in any other case.

rolling normalisation method proposed means some longer significant weather events (those that run over 2 plus days) will not be normalised as they were in DPP2. An example, for us, is the August 2011 snow storm event.

57. A breach in any one year is unlikely to signal material deterioration of the network however the Commission may be looking to pre-emptively shine a light on improvements to asset management processes and practices rather than address this after multiple limit exceedance events. This aspect however can be delivered by the proposed major event reporting.
58. The Commission commented in its main policy paper on the 1 April 2015 to 31 March 2020 reset in November 2014 that:

    "6.9 The quality standards employ the two-out-of-three year rule because this allows one-off poor performing years, which alone may not constitute an underlying material deterioration of reliability (for example, due to natural variability)......

    6.11 The reliability limits for the quality standards are set at one standard deviation above the historical SAIDI and SAIFI average to allow for a reasonable level of variability in reliability performance. Allowing for reasonable natural variability means that the quality standards better reflect underlying network performance.

    6.12 These different approaches to reduce the number of false positives work together as a package (along with data normalisation). They do this by taking extreme events and some variability into account. Therefore, the quality standards are more focused on performance over time than a single annual non-normalised measure."
59. We agree with the Commission's 2014 logic that the standard deviation, normalisation and two-out-of-three year rule work together as a coherent whole to ensure what is captured by breaches is material deterioration, and submit that the two-out-of-three year rule should be retained for unplanned outages rather than a move to an annual test.
60. The Paper also implies that incorporation of planned notification criteria into the assessment of planned SAIDI that informs the incentive is risk neutral. We are not aware that the Commission has access to the relevant data on planned notifications to establish this. We discuss this further below.
61. Once again, the publishing of enforcement guidelines by the Commission is an important component in providing for a transparent and certain regime around the quality path. This will allow us to understand the consequences of what is being proposed. We support the ENA's submission points on enforcement guidelines.

Unintended consequences of splitting planned and unplanned

62. In our submission on the DPP3 issues paper we did not support splitting planned and unplanned SAIDI and SAIFI. We appreciate that the intention is to reduce the perceived incentive to 'turn off' planned work, should a breach be imminent, in order to achieve the overall SAIDI/SAIFI limits. We don't believe that there is an issue to solve here. We believe there are also unintended consequences of splitting planned and unplanned, as proposed, that could lead to ongoing trade-off situations between planned and unplanned particularly given uneven incentives between them.
63. For instance, where an EDB becomes aware of distressed equipment on its network, presently a Class C interruption (but a non-notified planned interruption via the Paper's notification definition) may be initiated to address the issue. The benefit for the customer is that the interruption will be addressed efficiently and in a shorter time than if it was left to eventuate as a pure unplanned interruption. Where the incentive is stronger for unplanned interruptions an EDB may elect to delay the work, a planned outage, to allow proper notification taking the risk that an unplanned outcome might occur in the interim.

Calculation of planned assessed SAIDI

64. The draft determination that accompanies the draft decision details how the SAIDI and SAIFI planned assessed value is to be calculated.[18] The calculation departs materially from the way in which SAIDI and SAIFI has been assessed in the past.
65. The Paper is unclear whether the de-weighting for notification of planned interruptions is intended to be optional or compulsory. We seek clarification on this point.
66. The Paper creates a strong incentive to notify planned interruptions in accordance with the definition. We share our views on some of the implications of weaving the notification of planned interruptions into the SAIDI and SAIFI assessed formula below. Our overall conclusion is that the notification of planned interruptions should be removed from the incentive and be part of information disclosure for DPP3.

Definition for correct notification of planned interruptions

67. The prescriptive definition for correct notification of planned interruptions does not align with current industry practice. We don't think this is a positive enhancement for customers.
68. As the definition (and incentive regime) stands, the planned notification prescriptive requirements reduce EDB flexibility around notifications that may meet customer needs. This is important because we often alter interruption days and timeframes to work in with customer feedback. While this might not align with the

[18] DPP3 draft determination Schedule 3.1 page 54

definition provided, appropriate notification has been provided, it suits the customer and meets their expectations.

69. The Paper acknowledges the appropriateness of introducing new measures as information disclosure before linking them to incentives.[19] Therefore as a first step we recommend notification of planned interruption measures should be part of information disclosure and not linked to assessment of SAIDI or incentive mechanisms.
70. Notwithstanding our view to exclude notification of planned interruptions from SAIDI assessed and incentive mechanism, we comment on the specific design put forward in the Paper in the following points.
71. The Paper explicitly defines the components considered necessary to correctly notify a customer of a planned outage.[20] Broadly we are concerned that there is not a problem here that needs to be solved in the way the Paper proposes, that the Paper is considering quality metrics without having relevant data to assess what appropriate metrics would be and is being quite prescriptive around operational matters that may not enhance our customers' experience. There is a risk that the Paper attempts to represent our community expectations around outage notification in an inappropriate and granular way that reduces our ability to be flexible in our customer service.
72. Orion has reviewed its notification data for high voltage outages for FY19. Our data reveals that of all high voltage planned outages 7% were cancelled, 14% occurred on the alternative notified day, and only 27% occurred in a window of less than four hours (normally for minor jobs or work that is a subset of a bigger job).
73. In particular, the Paper says a distributor must provide retailers and major customers, or directly to all customers, with at least five full working days' notice of a planned interruption.[21]
74. Our current delivery services agreement with retailers requires Orion to provide advance notification of a planned interruption if via the retailer, at least 8 business days before the interruption, or at least 4 business days before the interruption where a customer is notified directly by us. In addition, the agreement puts an obligation on retailers to notify customers at least 4 business days in advance of the interruption. [22].

[19] DPP3 draft decision N47- "Our view is that the information required should first be collated, with a view to establishing compliance standards and potentially a financial incentive scheme for future DPP resets. Several parties supported introducing new measures as part of the disclosure regime rather than as part of the quality regime for DPP3[567]"
[20] DPP3 draft decision M51
[21] DPP3 draft decision M51.1.
[22] http://www.oriongroup.co.nz/assets/Customers/DeliveryServicesAgreement.pdf, Clause 6.3

75. The Electricity Authority's Principles and Minimum Terms for Delivered Electricity also sets out minimum terms and conditions for a consumer contract including that notice of a planned interruption, "which should be no less than 4 working days."[23]
76. The current Electricity Authority default distribution agreement states ten working days notice for notification via distributor to retailer and four working days notice via distributor direct to customer.
77. We suggest that the definition align with the Electricity Authority's notice periods by reference to them in the definition.
78. The Commission should be aware that when customers are notified of a planned interruption, it is common practice, to also notify an alternative day. Planned interruptions can be postponed to alternative days due to weather, contractor resource or equipment issues, or at the request of the customer. This is good for the customer as they are forewarned that certain circumstances may result in a change of the outage day and can plan accordingly. In Orion's case if the alternative day is required a second notification letter is sent to customers. In both cases, the customer is notified for the one potential event.
79. At times, distributors may notify customers directly of a planned outage in a shorter window, say 24 hours, via a direct mail drop. This only occurs where a small number of customers will be affected and all customers have been consulted and agree to the outage. The outage will often benefit the customers by avoidance of a potential unplanned outage. The new notification of planned interruption incentive is not in the customer's interest. While this is off-set by the risk of an unplanned outage it does still mean that an EDB is not rewarded through the planned notification incentive derating.
80. To meet the notified planned interruption requirements the definition states that planned interruptions are prominently located on the distributor's website or via other online means.[24]
81. Orion already has a comprehensive online visual locational representation for outages, both planned and unplanned at event level. We assume that the definition does not intend the information to be at ICP level. In any event a customer would need to be notified individually to be aware of the planned event. Subject to that clarification, we see no issue with this part of the definition for planned notification of interruptions.
82. To meet the notified planned interruption requirements the definition states that notification windows must be no longer than four hours[25].

[23] Clause 3.14(a) available at, https://www.ea.govt.nz/operations/retail/retailers/retailer-obligations/
[24] DPP3 draft decision M51.2
[25] DPP3 draft decision M51.3

83. Orion does not support this requirement and it is not in our customer's interests to do so. It is common practice for outages to be longer than four hours. In fact, our data shows that greater than 53% of outages are longer than four hours and 46% of outages are between 4 and 8 hours. One longer outage (as opposed to 2 or more shorter ones) can be in the customer's interest- not to mention more efficient.
84. Setting a defined four hour window contradicts the Paper's statement that "setting the planned quality standard over the full regulatory period…will allow distributors to schedule planned works in the way that works best for their business and consumers."[26] There are valid operational reasons why outages are longer than four hours. The nature of the work or location may require longer than four hours, for example, re-conductoring of overhead lines and rural reticulation with limited alternative supply options. We can expect more of this type of work as EDBs increase replacement and renewal activity across DPP3. A commercial customer may also request work to be done overnight so that it has less impact on their business, and for the same reasons, as much work as possible will be conducted during that period. It is often not in the customer's interests to have multiple short outages.
85. We are concerned that this part of the definition for notified planned interruptions creates an incentive to restrict work to four hour windows and this in turn can create undue safety risk for service providers through time pressure and operational inefficiencies where one interruption to complete work becomes multiple interruptions to complete the same work. The Paper, in setting a separate planned standard, indicates this would "give distributors greater flexibility on the timing of work requiring planned outages"[27] however this four hour restriction goes counter to that premise and reaches into the operational decision making of an EDB at a level that we consider to be inappropriate. We strongly support removal of this element from the notified planned interruption requirements.
86. To meet the notified planned interruption requirements the definition states that planned interruptions must occur entirely within the specified window[28].
87. Orion agrees that it is appropriate that, as far as reasonably practicable, outages should remain within the notified window. Naturally, there are situations that result in outages going beyond the notified window. For instance, issues can arise during the course of the work through equipment or weather issues. Most EDBs require service providers to specify a 'recall time' when applying for outages on the network. This provides an indication of how long it will take for the work site to be restored to a state it can be re-energised,

[26] DPP3 draft decision L32
[27] DPP3 draft decision L12.2
[28] DPP3 draft decision M51.4

if required. We also monitor service providers, and where a pattern of consistently going over time is identified we alert Orion contract managers who discuss this with the service provider. Overall, we see no issue with this part of the definition for planned notification of interruptions.

88. To meet the notified planned interruption requirements the definition states that planned interruptions are still counted for the purposes of assessing incentives even if the interruption does not eventuate[29]. Orion does not support this requirement as it adds unnecessary complexity for a situation that doesn't occur often (cancelled jobs occur 7% of the time according to our data).
89. We do not support the inclusion of a factor for intended interruptions in the calculation of assessed planned SAIDI and SAIFI given the trade-off required in administration, the low instance of this scenario and the lessor impact on the customer. The Paper recommends treatment of planned outages differently because they are less inconvenient for customers because they can plan accordingly[30]. If an outage becomes an intended interruption then it did not go ahead and has no duration or frequency effect on the customer. This is unless the Paper intends that the notified duration and frequency of the outage that did not go ahead is recorded as the SAIDI intended. The Paper's intention is unclear but in any event the outage will be captured by the 'notified correctly' or 'incorrectly' elements of the calculation when the work does go ahead. To remove unnecessary complexity, the intended interruption element should be removed from the calculation and the incentive.
90. If the final decision remains, despite our submission against it, that incentives should be applied to planned notifications then the definition of notification for planned interruptions should change to ensure we can deliver outcomes that our customers want.
91. As the definition (and incentive regime) stands, the planned notification prescriptive requirements reduce EDB flexibility and operational efficiency around notifications that benefit customers.

Major event

92. We agree, in principle, with the decision to replace major event days with a major event 3 hour rolling window, and to pro-rata the boundary value.
93. Notwithstanding our view that replacing major event days with a major event 3 hour rolling window is appropriate we point out that this deviates from the internationally accepted IEEE network research based approach. We are concerned that the Paper's theoretical approach may not reflect EDB capacity constraints

[29] DPP draft decision M51.5
[30] DPP3 draft decision L16

experienced during and after an event. For instance, it appears the quantum of major event average duration capped will significantly reduce compared to DPP2's approach however we are unsure, in practice, what the overall impacts of this will be over DPP3.

94. The paper and model are not consistent in their explanation of exactly how the 3 hour rolling approach (looking back or looking backwards and forwards) should be applied in practice. Provision of better clarity on this point would be useful.

Extreme event standard

95. The Paper acknowledges the appropriateness of introducing new measures as information disclosure before linking them to incentives[31] however this principle seems to have been disregarded in the introduction of a new extreme event compliance measure.
96. While we agree with additional information disclosure reporting for an extreme event (although we point out this will not indicate material deterioration), we disagree with setting an extreme event threshold that immediately links to a breach outcome.
97. We submit that there is a real risk that a breach linked extreme event will incentivise overinvestment. A reporting requirement, on the other hand, will encourage transparency, sharing of learning and continual improvement.

Enhanced reporting

98. The requirement for enhanced reporting of major events and extreme events provides greater transparency of asset management, engineering judgement and organisational response.
99. We agree with the requirement for automatic reporting on breach for planned and unplanned SAIDI/SAIFI. This will help to streamline the reliability related investigation process for both parties.

Quality incentives

100. Retention of the revenue linked incentive scheme is appropriate subject to our comments in the quality section above.
101. We agree with applying the revenue linked incentive scheme to SAIDI and not to SAIFI.
102. We note a mistake in the reliability standards and incentives model- cell D95 in workbook 'calculations' incorrectly uses the collar and cap rather than the target and cap to calculate the maximum loss percentage (which should correctly be 0.25% for Orion rather than 0.37%).

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[31] DPP3 draft decision N47- "Our view is that the information required should first be collated, with a view to establishing compliance standards and potentially a financial incentive scheme for future DPP resets. Several parties supported introducing new measures as part of the disclosure regime rather than as part of the quality regime for DPP3[567]"

Revenue cap

Timing of Annual Compliance statement

103. With respect to the price path, the purpose of the annual compliance statement is to set out the wash-up amount, rather than to show price compliance. This statement must be produced within 50 working days after the end of the assessment period, and requires director certification and is also subject to audit. With these requirements, the work to establish "actual revenue from prices" must be carried out in May, just 4 to 6 weeks after the assessment period ends.

104. Sundry revenues and expenses such as assets written off impact the price path and are more accurately obtained at the time of information disclosure at 31 August. In addition, with the industry wash up cycle for volume charges, the actual revenue for an assessment period will continue to change after March, and there appears to be no mechanism to capture and carry forward these differences.

105. We suggest two possible options to increase accuracy of information;
(a) Move to a separate price compliance statement: We understand that it may be desirable to capture the quality aspects of compliance (which is in the same statement) soon after the end of the assessment period, but the wash-up amount does not need to be calculated until prices are being set for the following year. Orion submits that all price related compliance (price setting, wash up amount, price related aspects of transactions) should be moved to a price compliance statement to be published before 31 March each year. This will ensure that the wash-up amount can be calculated with some certainty, and used in setting compliant prices. It will also spread the burden of auditing, splitting the task into two parts, **OR**

(b) **Move annual compliance statement to align with ID:** Orion submits, as an alternative approach, that the annual compliance statement should be moved to be published at 31 August each year aligning with the ID timeframe. This will ensure that the wash-up amount, sundry expenses and assets written off can be calculated with some certainty, and used in setting compliant prices. It will also align the auditing requirement with the ID audit requirement.

Annual compliance statement

106. With the definition of assessment period (which refers to a year in which compliance with a price quality path must be demonstrated), it is not clear that an "annual compliance statement" is not required during the first assessment period (clause 11.4(a)).

Revenue not received

107. The compliance formula applies prices to total quantities, and this would capture and include revenue that might not be collected due to a default. Distributors face point-credit-risks that are concentrated with retailers, and regulation prevents any reasonable steps to mitigate these risks.

108. One option would be to include an amount for bad debts in the opex allowance, but the magnitude of this cost is difficult to predict and the timing is irregular. We consider that a much better approach is to include an allowance within the calculation of chargeable quantities, so that only quantities that have been successfully billed should be included in the calculation of actual revenue from prices. This could be achieved in the definition as follows:

quantity	has the meaning given in the IM determination <u>but excludes any quantity that was not able to be charged or where payment was not made</u>

Power quality

109. In our submission on the DPP3 issues paper we submitted that ID requirements around LV network is a good place to begin around network performance and accountability. The Paper supports this.

DPP4

110. We support exploration of options during DPP3 for introduction of customer-facing measures in DPP4.

111. We support the decision that the development of a GSL scheme should be considered during the DPP3 regulatory period.

112. We also support consideration of reporting or framework based self-audit in DPP4 for resilience. We understand the EEA is developing a regime similar to AMMAT that focuses on resilience.

Determination Issues

Carry-over of pass through account balance

113. In the first year of DPP3 EDBs can claim an estimate of the pass through account balance from DPP2, and then this is washed up. The carryover (specified in schedule 1.7 (1) (a) needs to have a "1 + 67th percentile estimate of post-tax WACC" adjustment added. Also, schedule 1.7 (2) (a) the time value of money adjustment should be squared.

Quality incentive adjustment

114. Schedule 4 sets out the calculation for the quality incentive adjustment (Clause 5), but there appears to be no provision to carry over the quality incentive accumulated under DPP2. The application of the incentive is delayed two years under DPP2 and the proposed DPP3, so the incentive calculated under the previous determination needs to be referenced and included for the first two assessment periods.

Clarification of opex incentive amount for Orion

115. We submit that the draft determination needs clarification with respect to the opex incentive amount for Orion

(a) The draft IM still includes the clause:

"3.3.2(3) An opex incentive amount shall not be calculated:
(a) by Orion New Zealand Limited, for any disclosure year in a regulatory period commencing on, or prior to, 1 April 2020;"
(b) In reality, the version of the IM that included this clause only applies to Orion for the assessment period ending on 31 March 2020. Orion *did* have an opex incentive included in its CPP determination, and has a calculated opex incentive amount to carry forward and apply in DPP3.
(c) We request that the clause be amended (clarified) to:
"3.3.2(3) An opex incentive amount shall not be calculated:
(a) by Orion New Zealand Limited, for the disclosure year ending on 31 March 2020"
(d) A similar change is required to Clause 3.3.3(6)

Gains or losses on disposal

116. We understand that an allowance for gains or losses on disposal have not been included in the calculation of allowable revenue. We agree that these can more accurately be captured in the revenue assessment, and we understand that this is the approach that has been confirmed under PowerCo's CPP. To provide clarity under the DPP, we request that the definition of "Other Regulated Income" be amended as follows:

other regulated income	has the meaning given in the **IM determination** <u>and, for the avoidance of doubt, includes gains and losses on asset disposals</u>**.**

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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