Submission on Default Price Quality Paths for EDBs from 1 April 2025 (Draft Decision)

12 July 2024

1 Contents

2 Submission and contact details

Consultation	Submission on EDB DPP4 Draft Decision
Submitted to	Commerce Commission
Submission address	Ben Woodham, Electricity Distribution Manager infrastructure.regulation@comcom.govt.nz
Date submitted	12 July 2024
Submitter	Greg Skelton, CEO, Wellington Electricity Lines Limited (**WELL**)
Contact	Scott Scrimgeour, Commercial and Regulatory Manager
Email	[redacted]
Phone	[redacted]

3 Supporting submissions

Three other submissions are being made separately that respond to the Draft DPP4 Decision on our behalf. Figure 1 provides details of these submissions, including what Draft DPP4 Decision topic they are responding to.

The table includes a submission from the Electricity Network Association (**ENA**). WELL is a member of the ENA and participated in the submission development. We support their submission in general and our submission refers to some topics directly (these topics are listed in Figure 1.)

Figure 1- separate submissions made on WELL's behalf.

Submitter	Submission name	Topics the submission is providing on WELL's behalf
Oxford Economics Australia	OEA – Final EDB Escalation Report – 27.06.24	• Use of the All-Groups CGPI forecast to escalate the constant price capex allowance • Escalate all opex costs using the same cost escalator from LCI and PPI
PWC (on-behalf of the Big 6 networks)	Reopener Guidelines	• Proposing industry reopener guidelines to support the development of reopeners
ENA	ENA DPP4 Submission	• Refinements to the INSTA eligibility criteria. • Review of the revenue washup workings.

4 Document structure

This submission follows the structure provided in the Commerce Commission (**Commission**) '*Guidance and template for submissions on draft decisions*'. Feedback is provided to each draft decision using the same decision reference number and in the same order as the template.

We have added extra sections in the order of the consultation documents for topics that do not directly relate to the template questions.

5 Executive Summary

Wellington Electricity Lines Limited (**"WELL", "we", "us", "our")** welcomes the opportunity to submit in response to the Commerce Commission's (**Commission**) '*Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision (***The Draft Decision)**.

This reset is challenging because high inflation is increasing prices at a time when networks need a step change in investment to meet new demand from decarbonisation-related electrification. The Commission must balance affordability with providing new allowances so that EDBs can maintain their networks, build new capacity and replace ageing assets – investments needed to deliver the level of quality customers want and expect.

We note that the large price increase is also an outcome of the 'on-the day' approach used to set the risk-free rate component of WACC. Other regulatory judications smooth changes in the risk-free rate over time which reduces the likelihood of price shocks like we are currently experiencing. We think this should be a focus area for the future development of the regulatory framework.

Except for three important changes and a handful of less urgent adjustments, we think the Draft Decision provides the right balance between incentivising EDBs to invest while also providing affordable distribution services.

Changes are needed to allow a higher level of scrutiny for operating expenses that are critical to maintaining network quality (like the Risk Event Reopener provides for capital expenditure). The cap on capex allowances should be increased to better align with the step change in investment needed for New Zealand to electrify. Planned outage budgets need to reflect the increasing capex programme it supports and not historic outage levels which reflect lower capex spend from past regulatory periods.

Revenue smoothing and financeability

We agree and support the Commission smoothing the revenue path to reduce price shocks to consumers and to maintain affordability. We also support the Draft Decision to set prices with the expectation that EDBs will recover the smoothed revenue within the regulatory period and to introduce a financeability check. While an EDB is best placed to finance delayed cashflows from revenue smoothing, and it is their responsibility to finance new investments and the operation of the network, the regulatory cashflows must be able to support the cost of debt provided for by the regulatory WACC. The Draft Decision means that a network should be able to raise debt in line with the allowance for debt costs, setting a price path with the expectation of providing a normal return (meeting the purpose of Part 4, specifically incentivising networks to invest).

Allowances to maintain network quality

The key area of weakness in the Draft Decision is the opex-setting mechanisms. The Draft Decision misses allowances for critical maintenance and emergency response services needed to maintain network quality.

The recent June 2024 ‘Trends in local lines company performance’ shows that network quality has worsened since 2008. Critical to preserving service quality is a network's ability to maintain its assets and respond quickly to outages. If opex allowances cannot fund its maintenance programme and emergency response function, a network will have to reduce the volume of maintenance tasks and/or increase its emergency response times, which will increase the number and length of power outages, worsening network quality further.

The Draft Decision captures new costs like these using the step change mechanisms. However, some of the larger networks procure these services from a competitive market and the actual costs will not be known until the market tenders are received later in the regulatory period. In addition, the step change cap would exclude most of the increase. The field services contract can be a network's single largest cost. It makes up approximately half of Wellington Electricity’s total opex cost.

An opex reopener would allow the Commission to apply a higher level of scrutiny to new allowances in limited circumstances - when the allowances are needed to meet customer quality expectations. A reopener would also allow the allowance decision to be made when costs are known (when tenders are received), removing forecast errors and supporting the procurement of services from a competitive market and ensuring low long-term costs for consumers.

The Risk Event reopener is available in these exact circumstances (when additional investment is needed to maintain quality targets) but it only applies to capex expenditure. We think the regulatory model should be agonistic about the type of expenditure needed to maintain service quality. This submission suggests additional criteria that could be added to the Risk Event reopener so that it becomes agnostic to the types of costs needed to maintain network security.

Adjusting the Risk Event reopener would also allow the cap on step changes to remain in place for less critical expenditure, continuing to protect consumers from the higher probability of forecast errors from less certain forecasts and EDBs earning excessive profits.

Allowances to invest

We disagree that 125% cap provides a balance between incentivising EDBs to invest while limiting EDB's ability to extract excessive profits because:

1. The more robust 2024 AMPs are less likely to provide EDBs with windfall gains from over-forecasting and can be relied on to support a larger allowance. The 2024 AMPs have been independently scrutinised (by Innovative Assets Engineering (IAEngg)) and have been supported with additional information during the DPP reset process.
2. EDBs will not be able to defer the majority of their capex. If ageing assets are not replaced or new capacity is not built, the probability of outages will increase. We estimate that the Commission will need to process 25-36 reopeners a year depending on the proportion of projects that can be deferred. The large number of reopeners risk over-burdening EDB's and the Commission's resources, slowing the investment process and disincentivising investment.

We estimate that a 135% cap would reduce the number of reopeners by 22% or approximately 5-8 reopeners per year, a programme which will be more manageable and is less likely to deter a network from investing.

The impact of a step change in investment on network quality

The planned quality standards and incentives will not support the increase in capex allowances that have been approved and the additional capex from reopeners for customer projects that cannot be delayed until later price paths. Specially:

1. The step change in capex awarded by the Draft Decision plus the expected reopeners require a planned SAIDI budget that is above the planned SAIDI limit for Wellington Electricity – delivering the capex programme is likely to result in a quality breach. The draft SAIDI limit only considers DPP allowances and not the impact of reopeners.

2. The planned capex incentives mean we will be penalised for delivering the capex programme. This means the price path is being set at a level where we cannot expect to earn a normal return – the principle of financial capital maintenance will not be maintained.

We note that the Draft Decision suggests making a quality reopener application for a different planned SAIDI quality path to support the capex programme. We would be comfortable making a quality reopener if we could exclude the customer consultation element. Consulting with customers about the new quality path essentially means consulting about the capex programme it supports. Capex is set using a different process independent of a quality reopener and the consultation will provide no value. The high cost of customer consultation is also not consistent with a low-cost DPP.

Streamlining and refining the reopener process

Reopeners are not only needed because circumstances have changed or allowances have been reduced because "investments that were previously uncertain, insufficiently justified or unanticipated but have become more certain or justified during the period[1]".

The 125% cap on forecast capex is intended to be set at a level which balances incentivising investment and not allowing an EDB to excessive profits across all networks. The cap therefore must be generic and sector-wide rather than be tailored to specific businesses. This high-level approach will mean that investments excluded from the allowances will include those that are justified, anticipated and certain.

The Big Six networks have commissioned PWC to draft reopener guidance that can assist in the development of reopener applications. It will be essential that the reopener process is quick and the outcomes predictable to support essential investment.

We are also still concerned that the reopener does not support customer projects that fall at the start of the regulatory period. To meet the commissioning date, an EDB will need to start spending capex in the prior regulatory period before it can make a reopener application. An EDB could risk spending capex before a reopener is approved. However, the substantial IRIS penalty will mean that an EDB's Board is unlikely to approve capex expenditure unless it is supported by regulatory allowances. This means that EDBs may have to delay these types of customer projects until funding becomes available by making a reopener application.

The regulatory framework should be designed to support customers connecting to the electricity network, not dictate the timing of their project plans. Customer connections should be agnostic to the start and finish of a regulatory period. We will be presenting draft reopener applications parallel to the regulatory reset to minimise the impact the regulatory framework is having on customer delivery timelines.

6 Capital expenditure (capex)

6.1 Capex

6.1.1 (Decision C1) Use EDB 2024 AMP forecasts as the starting point for setting capex allowances.

We support using the AMP as the starting point for setting capex allowances. As highlighted in the paper, EDBs are in a good position to understand the needs of their consumers and any investment needed to maintain a secure electricity supply. Importantly, AMPs also provide detailed analysis supporting the capex investment profiles, including:

- Asset health assessments provide when assets need replacing before they impact quality performance.

[1] Para B194 of the Draft Decision.

- Demand and constraint studies show when new capacity is needed to ensure demand does not exceed capacity and assets are not damaged or supply is uninterrupted.

The external review of AMPs by IAEngg confirmed that regulated EDB's capex forecasting approaches provided in their AMPs broadly align with good industry practice[2]. While the review wasn't intended to verify AMPs[3], it does provide comfort that the AMP forecasts can be used with some confidence and can be relied on as a starting point.

6.1.2 (Decision C2) Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions.

We support the method of applying an overall cap to forecast allowance (as opposed to using capex gates for each asset class) but disagree with the 125% cap. A cap of 135% provides a better balance between ensuring networks have allowances available to invest when they need to maintain quality standards and not over-awarding allowances and risking networks earning excessive returns.

6.1.3 Applying a limit on aggregated forecast expenditure

We support the decision to set the allowances using the lower of an EDB's total forecast capex or a capped increase from a historical reference period. We agree that this approach is consistent with the low-cost DPP approach for setting allowances.

We also agree that there is no sensible method of applying gates to specific types of capex expenditure. The alternative methods considered during the Issues Paper were either complex and didn't align with the low-cost DPP approach to setting appliances, or the data wasn't available to support the proposed methodology.

The challenge with using data collected by the Information Disclosures framework is the information is collected for a different purpose i.e. the purpose of the Information Disclosures is to allow stakeholders to assess whether the purpose of Part 4 is being met[4]. The data collected was not intended to support the development of capex gates which means the data set does not include specific drivers for each capex category. Our experience from the capex gates developed for DPP3 is they create arbitrary cuts to capex forecasts rather than prudent capex profiles which reflect the investment needs of the network and do not over-forecast expenditure.

We also think that the value of capex gates has diminished with the introduction of the reopeners. There is less need for precise capex allowances now that networks can apply for additional allowances. The caveat to this is that the reopener processes still incentivise EDBs to invest; that the reopener process can manage a higher number of applications and that the process provides allowances when customers need them. The 125% cap should increase to ensure a manageable

---

[2] Para 2.32 of the Draft Decision.

[3] Para 2.30 of the Draft Decision.

[4] Part 4 Information Disclosure Reviews, Dec 2023, Framework paper https://comcom.govt.nz/__data/assets/pdf_file/0036/337896/Part-4-Information-Disclosure-Reviews-Framework-paper-14-December-2023.pdf, Page 5

number of applications (a different cap is proposed in section 6.1.5.2) and changes are needed to the reopener process to support projects that are commissioned at the start of the regulatory period (see section 6.1.10.2).

6.1.4 125% capex cap

We disagree with the Draft Decision that capping capex increases to 125% provides a balance between incentivising EDBs to invest while limiting EDB's ability to extract excessive profits. The 125% cap does not provide this balance for the higher levels of investment needed during the DPP4 period because:

1. AMPs can be relied on the reduce the risk of networks extracting excessive profits. The need for a higher level of scrutiny is not the same as in past years with less robust AMPs.
2. EDBs will be disincentivised to invest because they will have to make a large number of resource-intensive and long-lead time reopener applications. There is a significant time and cost overhead in these applications for EDBs and the work is done by skilled resources. There is an opportunity cost to the EDBs of keeping those people focused only on re-opener applications which in turn injects a non-trivial amount of friction into the investment decision-making.

6.1.5 2024 AMPs support a higher cap

Network AMPs and IAEngg's confirmation that the AMPs generally reflect good industry practice helps to mitigate the risks that EDBs will extract excessive profits. The purpose of the AMP and the Information Disclosure Determination that governs their contents, is to provide stakeholders with the ability to scrutinise and judge whether a network is meeting the purpose of Part 4. This includes limiting the ability of a network to extract excessive profits.

The director-certified AMPs provide detailed evidence to support a network's capex, like asset health checks that schedule when assets need replacing before they deteriorate and impact service quality. They include evidence like demand and constraint forecast modelling that schedules when new capacity is needed so that equipment is not damaged from overloading and an EDB can continue to maintain a secure supply.

While the AMPs are not verified, they have been externally reviewed by IAEngg who has confirmed that they generally reflect good industry practice. Additionally, in preparation for the DPP4 reset, the Commission requested additional information and explanation on capex drivers and changes to past AMP. 2024 AMPs have had a higher level of scrutiny than previous years. EDBs have also applied additional scrutiny and focus to the AMPs in response to New Zealand's Emissions Reduction Plan. The 2024 AMPs can be relied on to a greater extent than previous years.

The robust 2024 AMP can be relied on to mitigate the additional risk of EDBs extracting excessive profits from increasing the capex cap to 135%. The Draft Decision to increase the cap to 125% increase is only 5% more than the cap applied to total capex forecasts in the previous two DPP decisions. Increasing the cap to 135% is only a 15% increase from previous resets which is modest in relation to the step change in investment needed to meet future consumer demand increases. The risk of windfall gains from over-forecasting should not be given overweighted prominence or influence in the decision-making.

6.1.5.1 Disincentivising non-traditional solutions

Restricting capex allowances not only impacts the ability of a network to provide reliable and secure services, it also restricts its ability to consider flexibility. We agree with many submitters and the Commission that non-wire solutions may provide a more efficient solution than building traditional capacity once they are developed to the scale needed. However, these services will be funded indirectly from capex allowances and restricting access to these allowances will also restrict a network's ability to substitute capex allowance for opex allowance via the IRIS to pay for the services.

The IRIS incentivises networks to provide the most efficient solution, irrespective of whether it's funded from capex or opex. The IRIS rewards the network operator if a non-wire solution is more cost-effective than traditional capex by allowing them to keep some of the cost savings (approximately a third of the savings, the exact amount will depend on the final IRIS retention rate.)[5]

Under the current framework, a network will only be incentivised to select a non-wire solution if there is capex allowance available. While the INSTA is available for the development of non-wire solutions, the expectation of the Draft Decision is once flexibility becomes a business-as-usual option then it should be funded from allowances. Restricting capex allowances not only impacts the ability of a network to provide reliable and secure services but also restricts its ability to consider flexibility.

6.1.5.2 135% provides a better balance between incentivising investment and limiting an EDBs ability to extract excessive profits

We think the 125% cap is too low and that a 135% cap provides a better balance between limiting an EDBs ability to extract excessive profits and incentivising investment. We think increasing the cap to 135% will have a positive effect by reducing the number of forecast reopeners by 22% or approximately 5-8 reopeners per year, a programme which will be more manageable and is less likely to degrade a network's incentive to invest.

The Draft Decision considers capex allowances a 'base' and has been capped with the expectation that flexibility mechanisms, like reopeners and customised price paths (CPPs), are available for EDBs to apply for additional allowances[6]. While we agree that reopeners are an important tool for applying additional scrutiny to certain capital investments, the use of reopeners must be balanced with the resources needed to develop and assess reopener applications. Networks will not be incentivised to invest if:

- The number of applications is too high and an EDB does not have the resources to develop the applications.

[5] Noting that the INSTA is needed to correct for the IRIS not allowing capex and opex to be substituted across regulatory periods (para D25 of the Draft Decision).
[6] Para B118 of the Draft Decision.

- The number of applications is too high and the Commission does not have the resources to quickly assess, consult and reopen the price path. A long application process will impact the ability of a network to meet customer timeframes.
- The reopener process dictates the timing of investments and customer projects are delayed to fit within the regulatory rules. We think there are still fundamental issues with the reopener structure. We discuss this in section 6.1.10.2.

To understand the number of potential reopeners that may need to be developed and assessed we have estimated the number of annual reopener applications by dividing the total excluded capex value (the capex that does not have allowances after applying a cap on forecast capex) by the average value of a reopener. We have used the average value of System Growth capex projects from the AMP of the six largest EDBs, which is $6.5m, as a proxy for the average reopener value[7].

The calculation includes a range of adjusted 'total excluded capex values' to reflect that networks will defer some of the capex rather than apply for a reopener. We note that an EDB is likely to only defer capex as a last resort – deferring capex will increase the likelihood of an outage as the probability of an asset failing increases (from deferring asset replacement capex) or the probability of demand exceeding the network capacity (from deferring network growth).

Figure 2 provides our estimates of the number of reopener applications for a range of different capex caps and levels of deferred capex (expressed as a percentage of the excluded capex that is deferred until the next regulatory period).

Figure 2 – forecast number of reopener applications for all EDBs

Capex cap		125%		130%		135%		140%	
Excluded capex ($m)		1,179		1,026		912		847	
Number of reopeners		Number of reopeners		Number of reopeners		Number of reopeners		Number of reopeners	
Interval		Regulatory period	annual	Regulatory period	annual	Regulatory period	annual	Regulatory period	annual
Proportion of excluded capex deferred until next regulatory period	0%	181	36	158	32	140	28	130	26
	10%	163	33	142	28	126	25	117	23
	20%	145	29	126	25	112	22	104	21
	30%	127	25	110	22	98	20	91	18
	40%	109	22	95	19	84	17	78	16

The Commission will need to consider between 109 and 181 applications across the DPP period depending on how much of the excluded capex can be deferred until DPP5. Raising the cap to 135%

[7] Network Growth projects being the projects that an EDB is most likely to make a reopener application.

will reduce the number of reopener applications by 22% and will reduce the risk of an EDB being disincentivised to invest. Reducing the number of reopener applications will reduce both the networks and the Commission resources that will be needed to process the applications. More importantly, reducing the number of reopeners will reduce the likelihood of customer projects having to be delayed because of a large number of applications slowing both an EDBs and the Commission reopener function.

We recognise that a large proportion of the excluded capex is from Wellington Electricity's forecast capex programme. However, we will still need to apply for reopeners while we consider other price paths. This will still impact the number of reopeners overall and the Commission's ability to process them.

Increasing the cap to 135% does not change the number of EDBs who are not awarded their full capex forecast. Seven networks will still need to apply for additional allowances to maintain their quality standards. The higher cap will maintain 'tension' on funding and forecasts. A 135% cap also maintains a higher level of scrutiny via the reopener processes i.e. a proportionate level of scrutiny when compared to their step change in investment.

The investment step change indicated by some networks (including Wellington Electricity) may be better suited to a different price path (e.g. a CPP) rather than multiple reopeners. These networks will still need to make multiple reopener applications while they develop their price path application. Historically it has taken at least three years for CPP applications to be developed, verified and approved. At a minimum, therefore, all seven EDBs are likely to be making reopener applications for at least three years so they can maintain their network quality standards.

6.1.5.3 Adjustment to customer capital contributions

We support the method used to apply the capex cap and the treatment of capital contributions i.e. applying the cap to gross capex and then applying the cap to the capital contribution forecast separately. This method correctly reflects that the proportion of capital contributions compared to net capex could change over time if some capex categories grow faster than others. For example, we are forecasting System Growth capex to grow at a much faster rate than other asset categories. Our Contribution Policy means that little of the System Growth capex is funded by customer contributions. Therefore, capital contribution as a proportion of net capex will decrease as network growth capex increases. Applying the capex cap to net capex would incorrectly forecast higher capital contributions than our capital contribution policy would apply to customers.

6.1.6 (Decision C3) Use a five-year historical reference period for setting capex allowances [2019 to 2023 for the draft and 2020 to 2024 for the final determination] with an additional cost escalation adjustment.

We support using a five-year reference period to support the cap. The five-year period provides a balance between a large enough sample to average out investment timing differences and being recent enough to be reflective of current investment conditions.

We also support adjusting the cap to reflect that industry inflation has been higher than the all-industry inflation measures. As highlighted in the paper, ensuring that the cap captures cost increases incurred by the industry will help ensure the capex cap doesn't set allowances unintentionally low[8].

We disagree with the proposed 0.8% adjustment as this is not representative of the historic differences between all industry and industry-specific inflation. We suggest using 3.1% in line with our suggested approach to forecast capex inflation. Section 7.1.9 of this response provides more details.

6.1.7 (Decision C4) Include an allowance for the cost of financing, scaled in proportion to the capex allowance.

We support this approach. We also don't see any reason to change it.

6.1.8 (Decision C5) Include an allowance for the value of considerations for vested assets and spur assets equal to 2024 AMP forecasts.

We support this approach. We also don't see any reason to change it.

6.1.9 (Decision C6) Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to a nominal allowance

Our detailed submission points are provided in the joint submission with Orion and Vector titled "*Orion Vector and Wellington Electricity submission on cost escalators*".

We agree that the use of an All-Groups CGPI forecast is an appropriate base measure to apply for DPP4 given the present absence of widespread forecasting for a more specific and appropriate Stats NZ published index. This recognises the present complexity of developing a customised index for EDBs compared to the relative simplicity of using All-Groups CGPI.

We also agree with Draft Decision to include an additional adjustment to All-Groups CGPI is appropriate given that energy infrastructure is likely to face higher inflation than the general economy, over DPP4.

We disagree with the 0.8% uplift factor as it is based on a small reference period that reflects unusual post-Covid economic conditions. This period has the smallest historical differences between industry-specific and all industry inflation. The 'post-covid' economic conditions are unlikely to continue, and the 2019 to 2023 reference period is unlikely to be reflected in the next five years. Expanding the reference period results in much larger differences. Figure 3 provides longer-term differences between the all industry and industry-specific forecast which we think are more appropriate. In line with the recommendation from Oxford Economics Australia, we think the 30-year historic average difference of 3.1% provides the best measure. The longer reference period will capture a wider range of economic conditions. This is also close to the latest difference as of 2023 of 3.9%.

[8] Para B165 from the Draft Decision.

Figure 3 – Average annual difference in growth rates between EDB-specific CGPI and the All-Groups CGPI for different reference periods

Period	Average annual difference in growth rates
30 years (1994 to 2023) – longest available data set	3.1%
15 years (2009-2023) - first DPP	1.8%
5 years (2019-2023) - Draft Decision	0.8%
2023	3.9%

We also note that selecting a reference period that excludes, or at least dilutes, the impact of Covid is consistent with the Commission's selection of other reference periods. In the Cost of Capital IM final decision "the COVID affected period was excluded due to the large outliers and abnormal observations" [9]. When selecting the asset beta reference period, the Commission considered that to "use the COVID period would give too much weight to the pandemic on an ongoing basis" with regards to promoting Part 4 purpose and sufficient regulatory certainty.

6.1.10 Other regulatory tools

6.1.10.1 Reopener guidelines

Flexibility mechanisms will be an essential tool for networks to apply for additional allowances so they can continue to provide reliable and secure distribution services. It is important to note the flexibility mechanisms are not only needed because circumstances have changed or allowances have been reduced because "investments that were previously uncertain, insufficiently justified or unanticipated but have become more certain or justified during the period"[10].

The 125% cap on forecast capex is set at a level which balances incentivising investment and not allowing an EDB to excessive profits *across all networks*. The cap therefore must be 'generic' and 'sector-wide' rather than be tailored to specific business[11]. This high-level approach will mean that investments will be excluded from the allowances that are justified, anticipated and certain.

We agree with the need for flexibility mechanisms like reopeners, but not just to address uncertainty. They are also needed to support the low-cost approach to setting capex allowances. For this reason, we also think that EDBs and the Commission must focus on ensuring the reopener application process also reflects this low-cost approach. Specifically, that the application process for reopeners is streamlined, fast and efficient so that EDBs can invest in time to meet customer and reliability expectations. More importantly, the application criteria should be applied objectively, and

[9] Commerce Commission, December 2023. "*Part-4-IM-Review*-2023-Final-decision-Cost-of-capital-topic-paper" Page. 71, Para 3.228.
[10] Para B194 of the Draft Decision.
[11] Para B117 of the Draft Decision.

consistently and EDBs should be confident of what they need to provide and demonstrate to meet the criteria.

The Big Six networks have commissioned PWC to draft reopener guidance that can assist in the development of reopener applications. The guidance has been provided in a separate submission. We ask that the Commission review and provide feedback on the guidance so they correctly reflect how the Input Methodologies should be interpreted.

We think this will be an important tool to ensure reopener applications can support a robust and streamlined application process.

6.1.10.2 Changes needed to the reopener framework

Our submission to the IM Issues Paper[12] highlighted issues with the current reopener framework for customer projects that start in one regulatory period but will not be commissioned until the next regulatory period.

Large projects that meet the materiality limits of the reopeners tend to have long delivery timeframes that can be 2-3 years, especially if they require high-voltage reinforcement. These projects with long delivery times can span regulatory periods. If a growth project has not been awarded allowance as part of the DPP process, then an EDB will have to make a reopener allocation. An EDB can only make a reopener application once the price path is set. The challenge comes from customer projects which are scheduled to be commissioned at the start of the regulatory period and that do not have DPP allowances awarded or allocated. To meet the commissioning date, an EDB will need to start spending capex in the prior regulatory period before it can make a reopener application and bear the risk of IRIS penalties if it can't reprioritise other projects.

A network may have to choose between delaying the work programmes or having the customer pay for the project. Increasing customer capital contributions is an option for some projects. However, where a project has a large network reinforcement element that will benefit wider network customers (most emissions reduction-related demand increases in Wellington are expected from existing connections) then the connecting customer will be subsidising many other network users (like households transitioning to electric vehicles and away from using gas). To avoid the connecting customer cross-subsidising other customers, our Customer Capital Contribution Policy funds System Growth projects with shared benefits from the RAB and our network tariffs.

An EDB could also risk spending capex before a reopener is approved. However, the substitutional IRIS penalty will mean that an EDB's Board is unlikely to approve capex expenditure unless it is supported by regulatory allowances. This means that EDBs may have to delay these types of customer projects until funding becomes available by making a reopener application.

---

[12] Section 5.2.9, https://comcom.govt.nz/__data/assets/pdf_file/0021/323175/Wellington-Electricity-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf

The regulatory framework should be designed to support customers connecting to the electricity network, not dictate the timing of their project plans. Customer connections should be agnostic to the start and finish of a regulatory period.

Correcting this issue will be more important during the DPP4 period because there will be more reopener applications which will increase the likelihood of projects being in the scenario described.

We suggested two solutions in our submission to the Draft IM Decision. Our preferred solution is to allow a reopener to be approved in the preceding regulatory period and the approved amount automatically added into the allowance for the next regulatory period. To avoid double counting the capex if the allowance is awarded, then the project should be excluded from the capex forecasts that the DPP allowance is based on. This would be the same treatment as the LLC projects.

6.1.10.3 CPPs are poorly suited to sustained investment programmes

A Customised Price Path (CPP) is designed for discrete work programmes that can be delivered within a single regulatory period. However, many network emissions reduction-related work programmes will require a sustained step change in investment across multiple asset fleets over multiple regulatory periods. Our submission to the IM Issues Consultation analysed our 30-year investment programme, characterising that investment[13] as being a material step change from historic averages and sustained across multiple regulatory periods. The analysis also showed that while the need for the investment was highly probable, the timing of when to invest could change due to uncertain and changing investment drivers.

Rather than continue to submit multiple CPP applications for individual projects and incur the high costs of making multiple one-off funding requests, we think an individual price path (IPP), like that used for networks in Australia, the UK and Transpower, would now be more appropriate. Using an IPP for networks with large, sustained investment profiles could:

- Make it easier to shift investment packages between regulatory periods and potentially remove the need to reassess those investments, reducing regulatory costs.
- Include a longer-term/high-level investment programme to guide the movement of investment packages between regulatory periods.
- Allow the application process to be streamlined, reducing regulatory costs.

We understand that an IPP would require legislative changes to the Commerce Act 1986 and changes to the Act is the Ministry of Business, Innovation, and Employment (**MBIE**) responsibility. However, endorsement from the Commission would be an important step to encourage MBIE to include consideration of an IPP in their work programme.

[13] Case studies 4 and 5 of our submission to the Part 4 Input Methodologies Review 2023 – Process and Issues paper.

6.1.10.4 Modified or varied forms of a CPPs

We note that a CPP application can be modified to meet the particular circumstances of an EDB. Specifically, a CPP application doesn't have to be a full bottom-up price path and can be provided in modified or reduced formats like:

- Relying on existing AMPs and only providing additional information to strengthen an AMP.
- Taking a form like a streamlined CPP, focusing on a discrete investment path and an existing DPP for business-as-usual expenditure.

We support this approach as it could avoid unnecessary application costs for expenditure categories that haven't changed from existing practices.

We note that a modified application would have to be constructed using guidance from the Commission as to what would be accepted. The 'full' application timeframes are long (past applications have taken 3-5 years to complete) and expensive (millions of dollars). EDBs would need to be confident of a modified approach to avoid having to reapply because the information provided didn't meet the Commission's expectations, incurring additional time and cost.

We think this could easily be achieved by an early planning meeting with the Commission. This would require the Commission to provide opinions and feedback that could then be relied on to plan and execute an application process.

6.1.10.5 Large Connection Contracts (LCC)

We note the different approach to determining LCC eligibility. Our capex has been capped so it is assumed that potential LCC projects have not been implicitly or explicitly included in the DPP allowances.

We also note that the potential LCC projects disclosed in our AMP include System Growth capex to provide additional upstream network capacity needed to support the new connections. The wider network growth will also benefit other network users. As per our Capital Construction Policy, these costs will go on the regulatory asset base (RAB) and will be recovered from our network tariffs. This means if we use the LCC mechanism, we would also have to make a reopener application for the System Growth capex not directly funded by the connecting customers.

It may be more efficient for us to make a single reopener application for both the Customer Connection and System Growth cost components. Most LCCs will probably also require wider upstream network reinforcement on the Wellington network. The circumstances where the LCC is more efficient than using a reopener are likely to be limited.

6.1.11 Additional reporting

We support the additional reporting if it can be aligned with a network's good business practice and doesn't add costs. EDBs allowances are already under pressure as their delivery programmes increase and they incorporate new non-wire solutions into our asset planning.

We support carefully designed Annual Delivery Reports and reporting a network’s forecast reopener programme. We do not support further reporting on Capital Contribution Policies as detailed assessments against the Electricity Authority’s Pricing Principles already exists.

6.1.11.1 Annual Delivery Reports (ADR)

We support the development of ADR as a tool to provide confidence about an EDB’s ability to deliver work programmes and transparency about reprioritisation decisions. The reporting structure will have to be carefully considered so that it captures the complexities around capex planning decisions. EDBs’ work programmes change significantly and regularly for changes in customer work programmes, adjustments to asset health assessments, unforeseen cost escalations, and network fault repairs. EDBs have limited capex allowances and do not have contingencies set aside for unexpected changes. Any new programme will require a programme adjustment unless it is eligible for a reopener.

The ADR strategy will need to capture:

- Capex reprioritisations due to new projects or changes in project prioritisation
- Capex reprioritisations due to refined cost forecasts or unforeseen cost escalations (usually AMPs are based on high-level forecasts and are updated during the detailed design phase)
- Capex deferred due to alternative, more efficient wire or non-wire solutions
- Capex substituted to fund non-wire solutions
- Capex substituted for reprioritised opex cost increases

Capex programming is complex and care must be taken for the reporting to remain aligned with the low-cost DPP.

6.1.11.2 Changes to Capital Contribution policies

The current Capital Contribution Policy requirements require EDBs to show that the policy aligns with the Electricity Authority’s Pricing Principles. The Commission should be able to take comfort that if the Capital Contribution Policy aligns with the Pricing Principles then they will also align with the long-term best interests of consumers. This assessment is already available to the Electricity Authority as part of the Capital Contribution Policy and as part of the Pricing Methodology reporting (EDBs are required to show how tariffs and Consumer Contributions align with the principals) and additional reporting is not required.

6.1.11.3 Reopener programmes and capex prioritisation

We strongly support this approach as it will provide early guidance on what projects will have to be delayed into the next regulatory period. Delaying any project will have an impact on quality because:

- Deferring asset replacement capex increases the probability an asset could fail.

- Deferring system growth investment increases the probability demand will exceed the rated capacity of an asset, potentially damaging equipment and increasing the likelihood of an outage.

An EDB will then have to consider whether the probability and impact of delaying the investment will require a quality path reopener.

We will be presenting our rationalised and reprioritised capex programme in parallel to the DPP4 reset process. This will include reopeners for customer projects forecast for early 2025 (as described in section 6.1.10.2)

7 Operating expenditure (opex)

We agree with the Commission that opex allowances are being set in a changing and uncertain environment[14]. As highlighted in our submission to the DPP4 Issues Paper, new opex allowances will be needed to support new functions and changes to existing functions including but not limited to:

1. The delivery of increasing capex programmes – this includes planning engineers, back-office support functions like finance, procurement and legal services etc.
2. The ability to use demand-side flexibility to maintain network security and provide lower long-term prices.
3. Meeting changing customer quality expectations by developing low voltage (LV) network management tools to monitor and manage LV quality.
4. Maintaining insurance coverage for customers by funding faster than inflation increases in insurance costs.

We do not support the Draft Decision because it misses allowances for critical maintenance and emergency response services needed to maintain network quality. The recent June 2024 '*Trends in local lines company performance*'[15] shows that network quality has worsened since 2008. Critical to maintaining service quality is a network's ability to maintain its assets and to respond quickly to outages. If opex allowances cannot fund its maintenance programme and emergency response function, a network will have to reduce the volume of maintenance tasks and/or reduce its emergency response times, which will increase the number and length of power outages, worsening network quality further.

We note and support the draft decision to provide some new allowances. However, the capped step changes and the other backwards-looking opex mechanisms do not capture all operating cost increases.

---

[14] Para C5 of the Draft Decision
[15] The Commerce Commission, June 2024, Available at https://comcom.govt.nz/__data/assets/pdf_file/0022/356620/Trends-in-local-lines-company-performance-25-June-2024.pdf Page 5

Applying a higher level of scrutiny for expenditure which impacts quality

We would support the Draft Decision if it provided an ability to consider and scrutinise material changes in operating expenditure needed to maintain a network's quality standards. We understand why a cap is applied to step changes and agree that customers need to be protected from windfall gains from excessive forecasts.

A reopener should be available to networks to apply for additional opex allowances needed to maintain a network's quality standards. This would allow the Commission to apply a higher level of scrutiny to new allowances in the limited circumstances when the allowances are needed to meet customer quality expectations.

The Risk Event reopener is available in these exact circumstances but it only applies to capex. We think the regulatory model should be agonistic about the type of expenditure. Expanding the Risk Event reopener to include opex would not change the risk it is mitigating, it would just require expanding it to include allowances for operating expenditure.

We suggest reopener criteria and explore how a reopener is a better fit to the purpose of Part 4 than applying step changes in section 7.1.1.1 of this submission.

The regulatory framework relies on setting appropriate opex allowances

We re-iterate our comments from our submission to the DPP4 Issues Paper. The regulatory model relies on EDBs having appropriate opex allowances to incentivise EDBs to '*improve efficiency and provide services at a quality that reflects consumer demands'*[16]. Specifically, the IRIS cost-saving incentive relies on the regulatory model capturing all expenses that a prudent and efficient operator needs to operate their networks. As highlighted in The Issues Paper[17], the overall 'revealed cost' approach to setting incentives, sets the incentive targets at the expenditure levels needed to operate the network. It then rewards or penalises the EDB for operating the network more or less efficiently (i.e. spending more or less than the incentive targets). While the draft decision does provide allowances for some new costs, there are still unavoidable costs that have been missed. An EDB will need to find savings just to avoid IRIS penalties, incurring penalties when they can't find savings. The price path will be set at a level that an EDB cannot expect to earn a normal return[18] .

We think this can be corrected by adding additional flexibility mechanisms to capture material cost increases not captured by the Draft DPP Decision. These flexibility mechanisms can be designed to be low-cost and (in the case of the proposal to amend the Risk Event reopener) allow a higher level of scrutiny to be applied to expenditure that is critical for maintaining the quality standards.

[16] 52A (1) (b), Part 4 of the Commerce Act 1986.
[17] D10 from the DPP4 Issues Paper
[18] Not meeting the purpose of Part 4, 52 (A) (a), providing incentives to invest or the principle of providing real financial capital maintenance used to measure whether the purpose of Part 4 has been meet.

7.1 Opex

7.1.1 (Decision O1.1) Apply a base-step-trend approach to forecasting opex.

We disagree with using the base-step-trend method without the addition of other flexibility mechanisms as it will not capture all new costs or steps in existing costs. The inputs into the base-step-trend framework are either functions of past expenditure or the application is too rigid to capture unavoidable cost increases. Specifically:

1. The base year will only include past costs.
2. Like some decarbonisation-related capex projects, the timing and size of some expenditure is currently uncertain and won't be known until after the price path is set. The step change criteria may not capture these costs, and even if it does, will then cap the step change to reflect the low-cost nature of the DPP.
3. The network growth factors rely on the relationship between expenditure and the growth variables being captured in the reference data set. New costs or non-liner changes in the relationship between cost and outputs will not be reflected in the reference data set and therefore will not be provided for in the elasticity metrics.
4. The cost escalators won't capture inflation for cost with market conditions that differ from those reflected in the LCI and PPI inflation indexes. For example, insurance costs fluctuate at significantly different rates between regions within New Zealand and are driven by international markets.

On the Wellington network, the allowances provided by the proposed base-step-trend method will not cover:

- Above inflation insurance cost increases after year 1 (costs not covered in the step change). It will also not cover works that have been deferred because of insurance increases in the DPP3 regulatory period.

The step change provides some relief but we expect it will cover less than half of the expected increase in operating costs. It will also mean that, amongst other things, we cannot afford to purchase consumption data or the resources needed to develop and operate an LV management function.

Other networks will also have unavoidable, material expenditure that will not be captured by the base-step-trend methodology. In the case of costs like that for field maintenance services, that expenditure could be critical to maintaining a secure electricity supply and for meeting a network's regulatory targets.

Additional flexibility mechanisms, specifically an opex reopener, and an insurance pass-through, would correct the weaknesses in the base-step-trend methodology while maintaining the low-cost nature of the DPP. We think the application of the base-step-trend framework proposed in the Draft Decision would be fit for purpose with these additions.

7.1.1.1 Opex reopener for expenditure that directly impacts network reliability

The purpose of Part 4 includes providing incentives to provide services at a quality that reflects consumer demands[19]. The proposed step-change decision for field service cost increases and the cap on the overall step-change means this purpose is not being met. A network relies on its field services to maintain its assets so quality performance doesn't deteriorate and to quickly fix faults after outages. Any degradation in these services will have a direct impact on quality – a reduction in allowances will mean a reduction in the maintenance programme and a reduction in fault response times.

Assessing increases to field service costs (and other functions that have a direct impact on service quality) using opex reopener would more effectively promote Part 4 purpose than the current step change mechanisms. A reopener would provide better incentives for suppliers to invest and provide services at a quality that reflects consumer because it will:

- Allow a higher level of scrutiny to be applied to a higher-value cost increase. Maintenance field services are likely to be an EDB's single largest operating expense. Maintenance services make up approximately half of Wellington Electricity's total opex.
- Allow the application and allowances to be adjusted when market tender responses are available, ensuring networks aren't over- or under-funded – incentivising an EDB to invest (Part 4, 52A (1) (a)) and ensuring the network doesn't earn excessive profits (Part 4, 52A (1) (d))
- Allow a higher level of scrutiny to be applied to allowances for functions that directly impact network quality (ensuring a network can deliver a level of quality customers want (Part 4, 52A (1) (b)).
- Avoiding arbitrary step change caps on allowances for functions that directly impact network quality (Part 4, 52A (1) (b)).

A reopener would allow a higher level of scrutiny to be made at a time when the costs were better known. Criteria like those applied to the Risk Event capex reopener would ensure that additional allowances would only be awarded when new allowances are needed to maintain a secure electricity supply. Reopener criteria could include:

1. The additional expenditure is needed to maintain current quality levels and to avoid consumers experiencing longer and more frequent power outages that could result from deferred maintenance;
2. The same materiality clauses as currently applied to existing reopeners. The $2.5m minimum would exclude expenditure that networks could be funding by re-prioritising existing functions.

[19] Part 4 52A (1) (b) of the Commerce Act 1986.

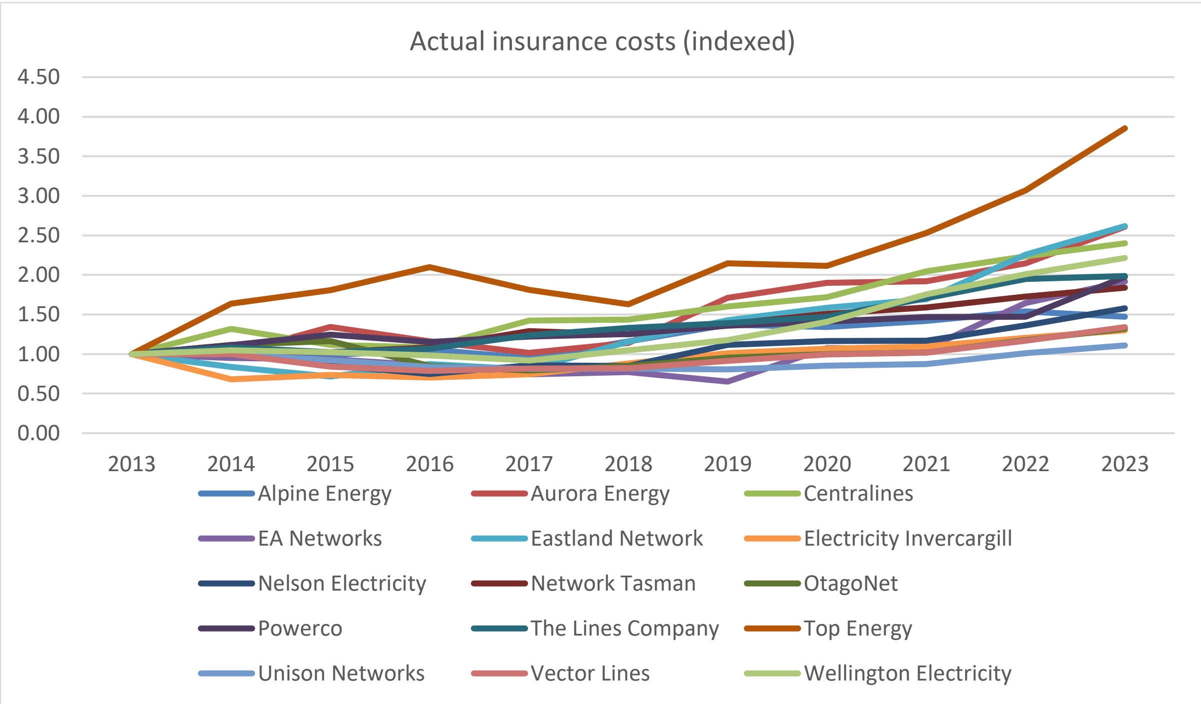
Providing a limited ability to reopen opex allowances could be provided by a new reopener or by amending the current Risk Event reopener (expanding it to include opex for maintenance needed to maintain service quality).

7.1.1.2 A step change won't capture insurance costs

The step change mechanism will not accurately capture insurance costs because insurance costs are difficult to forecast and brokers will generally only provide forecasts one year out. A network will only be able to provide sensible forecasts for a step change for the first year of the DPP4. Insurance cost increases are driven by international markets and are uncertain in the medium term (more than one year out).

This is shown by comparing network Information Disclosure insurance costs since 2013. Figure 4 was provided in our response to the DPP Issues Paper and shows the wide variability of cost changes between networks and over time. Cost increases since 2013 have varied between 0% and 380%. On average, insurance costs have increased by 56% since 2013 or 39% since the start of DPP3.

Figure 4 – insurance cost changes from 2013 for non-exempt networks.



We think insurance costs should be treated as a pass-through as the primary beneficiary is the consumer and networks have little control over costs.

We disagree with the Draft Decision assessment of the pass-through assessment criteria. Insurance cost increases are outside of the control of networks as prices are set by global markets and trends. We have on-site asset inspections by insurers, annual insurance reviews and presentations, and purchase insurance using our international brokers and we still have no influence over the price.

If insurance was to be treated as a pass-through then networks would have an obligation to ensure that the level of coverage was appropriate and they purchased insurance using prudent procurement practices. Networks could annually publish director-certified insurance broker advice that coverage levels were appropriate and insurance was purchased at market rates using prudent procurement practices.

7.1.1.3 Insurance as a passthrough

We disagree with the Draft Decisions assessment of insurance against the pass-through criteria. The Commission's assessment doesn't consider potential mitigations to the criteria assessment findings and makes incorrect assumptions about a network's ability to influence prices. Figure 5 summarises our assessment of the pass-through principles provided in our submission to the IM Draft Decision[20] and the Commission's assessment.

Figure 5 – comparison of pass-through assessments

Definition of a pass-through is provided in clause 3.1.2 (3)	The Commission's assessment provided in Para C104 of the Draft Decision	Our assessment provided in the IM review
associated with the supply of electricity distribution services	Yes, the criteria is met	Yes, insurance is to provide customers with the ability to cover the costs of repairing or replacing assets damaged in a natural disaster.
outside the control of the EDB;	Not met	The majority of insurance cost fluctuations are outside of the control of an EDB. While good procurement practices can provide some cost savings, the majority of movement is market driven.
not a recoverable cost	Yes, the criteria is met	Not a recoverable cost
appropriate to be passed through to consumers	Yes, the criteria is met	Customers are best placed to bear the risk of cost fluctuations as it is the customers who benefit from maintaining a prudent level of insurance coverage.
one in respect of which provision for its recovery is not otherwise made explicitly or implicitly in the DPP or, where applicable, CPP; and	Yes, the criteria is met	If insurance was included as a pass-through, then opex allowances would have to be reduced by the same amount to ensure the cost was not double counted.
come into effect during a DPP regulatory period or, where applicable,	Not met	This criteria restricts pass-through costs to only new costs which appears unnecessarily restrictive and is unrelated to the form of the cost. We do not believe the criteria should restrict existing costs from being considered as a pass-

[20] Wellington Electricity, July 2023. https://comcom.govt.nz/__data/assets/pdf_file/0021/323175/Wellington-Electricity-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf, Section 5.6.1

Definition of a pass-through is provided in clause 3.1.2 (3)	The Commission's assessment provided in Para C104 of the Draft Decision	Our assessment provided in the IM review
CPP regulatory period.		through.

We disagree with the Draft decision that keeping insurance in the allowances rewards suppliers who take active steps to reduce their insurance costs[21]. Insurance costs are outside of the control of networks. Networks cannot materially influence global prices. Any IRIS reward or penalty is simply a reflection of the fluctuation of market insurance prices. Wellington Electricity has access to global experts and can pool our buying power with other electricity networks in Australia (South Australian Power Networks, United Energy, CitiPower and Powercor), the United Kingdom (UKPN), and Hong Kong (Hong Kong Electric). Even with this buying power, we cannot meaningfully influence the price.

The Draft Decision also said it is not practical or low-cost to treat insurance as a pass-through. Again, we disagree. Networks could provide an annual, director-certified if necessary, expert report confirming coverage levels are prudent. They could also disclose their procurement process to ensure they are procuring insurance at market rates. This could be done with little additional effort from the Commission and for a modest cost increase from networks for the expert report, meeting the low-cost principle.

The Draft Decision also noted one reason the IM review decided not to treat insurance as a pass-through was made because of 'the importance of retaining incentives for suppliers to manage their risks efficiently – including through the types of insurance they hold[22]". As highlighted above, if networks don't have the allowance to purchase insurance, then they will reduce coverage to the detriment of consumers. Insurance is for the benefit of the customer – reducing the amount of any future price increases needed to repair equipment damage after a natural disaster. Networks are made whole post-event for repairs and equipment replacement costs that insurance doesn't cover via a CPP or by making a reopener application. Currently, networks are incentivised to reduce coverage and increase a customer's exposure to post-event recovery costs in response to an insurance cost increase.

7.1.2 (Decision O1.2) Use 2024 as the base year. [2024 AMP forecasts used for the draft decision]

We support using the 2024 AMP opex for the draft decision and then using the 2024 actual opex for the final base year.

Our 2024 AMP figure reflects 11 months of actual expenditure (we forecast the last month). It will be a good estimate of the final opex figure provided in this year's Information Disclosures.

[21] Para C108 of the Draft Decision.
[22] Para C107 of the Draft Decision

We also support using actual opex expenses for the regulatory year ending 31 March 2024 in the final determination. The latest actuals will be the most reflective of future spending.

7.2 Opex step changes

7.2.1 (Decision O2.1) Consider proposed step-changes against a defined set of factors, incorporating judgement.

On balance, we agree with changing the decision-making framework to a judgement-based framework, rather than applying strict acceptance criteria.

We do not think the current framework provided any value. Its application rarely provided allowances for new costs even though networks incurred new costs not captured in the allowances provided.

7.2.1.1 Option one did not provide regulatory certainty

We also think that the past application of the criteria was not always consistently or objectively applied, and it didn't provide the regulatory certainty that is highlighted as one of the key advantages for retaining the past approach (option 1)[23].

As highlighted in our submission to the Issues Paper, WELL requested additional allowances for increasing insurance costs as part of our transition from a CPP to DPP3. The price-setting process used the DPP3 step change criteria. The step change request was rejected because the increase in insurance costs was deemed as not being material. The step change criteria did not provide a measure of what would be considered material. The increase was $0.47m p.a. or $1.9m across the DPP period which is the equivalent of 1.5% of total opex. We note this increase is close to the reopener materiality criteria which is set at a level which reflects the high cost of reopening the price path (a cost a step change doesn't incur).

7.2.1.2 Decision precedents will provide regulatory certainty for future resets

We agree that the main weakness of the proposed approach is that a level of judgement will be needed which will make the step change decisions subjective[24]. However, we think that consistency in decision-making can be provided by using final decisions as precedents for future decisions.

We also note the DPP reset process provides opportunities to provide feedback where we think that decision making is inconsistent or doesn't reflect the criteria:

- Feedback on the application on the step change criteria during the Issues Paper consultation.

[23] Para C44.2 from the Draft Decision.
[24] Para C47.1 from the Draft Decision.

- Feedback on the Commission's early thinking during DPP workshops. The Commission opex setting workshop with ENA members provided a valuable opportunity to test what evidence was needed to support a step change.
- Feedback on the draft step change decisions (i.e. this submission).

7.2.2 (Decision O2.2) Step-changes should be significant.

We agree that 'proportionate scrutiny' is important to balance the size of the cost increase with the evidence provided.

7.2.3 (Decision O2.3) Step-changes should be adequately justified with reasonable evidence in the circumstances.

This is an important change. As highlighted in the narrative, evidence is often not available to verify a new cost. It is important to allow some discretion for cost increases that can only be estimated.

7.2.4 (Decision O2.4 to O2.6) other step-change criteria

We support the Draft Decision.

7.3 Step change decisions

Our preferred solution is to remove field service and insurance from the step changes and apply other mechanisms that will capture the actual costs. However, if the step change is retained for these costs, we have provided updated forecasts which we have provided in the Appendix.

7.3.1 (Decision O3.1) Include a step-change to reflect increasing insurance costs.

We do not think a step change is the correct mechanism to apply to insurance costs. Advice from our insurance broker is that insurance is difficult to forecast for more than one year in advance and brokers generally will not provide forecasts beyond this point. Insurance prices are a function of many different factors that are uncontrollable and difficult to forecast like available market coverage, changing natural disaster risk assessments and payouts for actual events.

We think that insurance should be treated as a pass-through like it is for bushfire insurance in Australia. Customers are the beneficiary of a network maintaining prudent levels of insurance coverage and are therefore best placed to bear the risk of cost fluctuations. Passing all risk of cost escalations onto networks, incentivises networks to reduce coverage and increase a customer's exposure to post-event recovery costs in response to the insurance cost increase.

We disagree with the Draft Decisions assessment of the pass-through assessment criteria. The previous section 7.1.1.3 re-examines the pass-through criteria and suggests mitigations to the Commission's concerns that a pass-through would not incentivise efficient coverage and isn't a low-cost mechanism.

If Insurance is retailed as a step change, then our broker estimate provided as part of the Issues Papers will still be the most accurate forecast.

7.3.1.1 A step change will not capture the impact of past increases

A step change also does not capture the impact of past increases. While past cost increases will be in our base year, we have had to defer other essential work to meet the cost increase and avoid an IRIS penalty. WELL has experienced above-inflation insurance cost increases which now means we have to find $1m in savings each year (equivalent to 3-4% of our total opex allowance) to cover the gap in allowances. While we have found some permanent efficiencies, some of the savings have come from deferring work activities or forgoing nonessential functions like customer consultations, LV quality management and by deferring non-essential maintenance.

7.3.2 (Decision O3.2 to O3.5) step change decisions

We support the decision to provide step changes for greater customer engagement, low voltage (LV) monitoring and smart meter data, increasing cyber-security costs and for software as a service.

7.3.3 Step changes that were have declined - retendering our field services contract

The draft decision was to not award a step change for retendered field service agreements. The step change was declined because there is a 'strong argument' that the increase should be captured through the application of the trend factors. 'The onus will be on the EDBs in response to the draft decision to adequately prove that the increases will be significantly above inflation, and that it remains appropriate for them to accept such a tender compared with alternative options[25]'.

We think that an opex reopener would provide a better tool for assessing changes in the costs of field services. An EDB could make a reopener application once they receive vendors' prices for the market tender. See section 7.1.1.1 of this response for a detailed explanation.

If an opex reopener isn't available, then an opex step change is the next best mechanism. An EDB can only meet its regulatory quality targets if it can fund the maintenance and emergency outage response functions needed to maintain service quality.

Accepting a tender is the most appropriate procurement option

Wellington Electricity has a policy and a strategy of outsourcing when there is a competitive market for those services. Procuring from a competitive market will provide the lowest long-term prices for consumers. Competitive tension incentivises vendors to provide the lowest price they can, or risk not winning the contract. The contract term is for five years which also incentivises vendors to offer the lowest price or risk having to downsize their business if they don't win.

We did consider bringing the service in-house but decided not to because it would increase costs beyond what the allowances could support, and it would increase prices to consumers. We do not believe that in-house or related-party services provide real competitive tension.

[25] Table C3 of the Draft Decision.

7.3.4 (Decision O3.7) Cap aggregate step-changes (in real terms) at 5% of trended opex excluding step-changes.

We support the approach of applying a cap if:

1. An opex reopener is available for critical expenditure needed to maintain a network's quality standards. Applying an arbitrary cap to critical delivery functions could inadvertently impede an EDB's ability to meet its quality expectations. We think a cap makes sense for the reason provided in the Draft Decision if critical expenditure could be excluded for a more detailed scrutiny.
2. Add a minimum total cap before the 5% of total opex sliding scale applies to better reflect the point at which all networks would consider a CPP. The minimum total cap reflects the point up to which a customer would be better off applying the proposed low-cost step change acceptable criteria. Above this point, a customer would be better off paying for a share of a CPP application to apply a higher level of scrutiny.

We estimate that past CPP applications, conservatively and on average, have cost approximately \$5m per application. Approximately \$2m for the EDB to develop the application and \$3m to verify it. Of the \$5m, about \$4.3m would be funded by customers either by the direct recovery of verification costs or via the IRIS. \$0.7m would be unrecoverable by an EDB and would have to be funded from their profits.

It is not in the customer's best interests for a network to apply for a CPP unless the amount that customers are at risk of overpaying (i.e. allowances providing a windfall to the EDB) is greater than the \$4.3m in CPP application costs. The IRIS provides the customer additional protection by limiting how long a network can keep the windfall amount to five years. The Draft Decision estimates that a customer would pay 34% (the IRIS retention factor which is based on the current WACC estimate) of any allowance windfall.

The equivalent allowances at which point a customer would be better off funding a CPP will depend on how much of the allowance awarded, over-forecasts actual costs. Figure 6 provides a matrix of how much a customer would pay for different over-forecast amounts. The amounts have been adjusted by the IRIS retention factor reflecting that after five years allowances will be adjusted down to reflect the overpayment. The vertical axis of the matrix provides a range of total step change amounts and the horizontal axis provides the proportion of the total step change allowance that has been over forecast. The matrix is shaded grey when the combination of total step change allowance and over-forecast percentage means a customer would be better off applying for a CPP.

Figure 6 – the cost of over-forecast opex allowance to the customer

	Proportion of over-forecast (adjusted by the retention factor)					
Total step change allowance	\$m	10%	20%	30%	40%	50%
	26.0	0.9	1.8	2.7	3.5	4.4
	27.0	0.9	1.8	2.8	3.7	4.6
	28.0	1.0	1.9	2.9	3.8	4.8
	29.0	1.0	2.0	3.0	3.9	4.9
	30.0	1.0	2.0	3.1	4.1	5.1
	31.0	1.1	2.1	3.2	4.2	5.3

	Proportion of over-forecast (adjusted by the retention factor)					
	32.0	1.1	2.2	3.3	4.4	5.4
	33.0	1.1	2.2	3.4	4.5	5.6
	34.0	1.2	2.3	3.5	4.6	5.8
	35.0	1.2	2.4	3.6	4.8	6.0
	36.0	1.2	2.4	3.7	4.9	6.1
	37.0	1.3	2.5	3.8	5.0	6.3
	38.0	1.3	2.6	3.9	5.2	6.5
	39.0	1.3	2.7	4.0	5.3	6.6
	40.0	1.4	2.7	4.1	5.4	6.8
	41.0	1.4	2.8	4.2	5.6	7.0
	42.0	1.4	2.9	4.3	5.7	7.1
	43.0	1.5	2.9	4.4	5.8	7.3
	44.0	1.5	3.0	4.5	6.0	7.5
	45.0	1.5	3.1	4.6	6.1	7.7
	46.0	1.6	3.1	4.7	6.3	7.8
	47.0	1.6	3.2	4.8	6.4	8.0

Assuming a conservative assumption that the step change forecasts are 30% higher than actual costs, the total step change amount would have to be greater than $43m before customers would be better off paying for the CPP to provide a higher level of security.

We think a conservative approach to the step change cap would be to assume an ultra-conservative starting cap of $26m (a 50% over forecast rate) before the 5% applies i.e. the cap on the total step change amount is set at the greater of $26m or 5% of total opex.

7.4 Opex trend factors - inflation

7.4.1 (Decision O4.1) Escalate all opex costs using the same cost escalator.

Our detailed submission points are provided in the joint submission with Orion and Vector titled "*Orion Vector and Wellington Electricity submission on cost escalators*".

We do not support using the same cost escalator across all opex costs. As supported by our Oxford Economics Australia submission, we advocate for an alternative cost escalator for network opex that reflects a closer relationship with capex drivers. This is because non-labour costs for network opex are similar to capex costs. For example, non-labour inputs for network opex include electrical materials, plant and traffic management and these costs will experience the same cost pressures as network capex.

Whereas non-labour inputs for non-network opex are office-based and not specific to electricity distribution. The producer price index (PPI) bundle of goods[26] is an appropriate measure to apply to non-network costs because the cost pressures align.

[26] Purchase of materials, fuels and electricity, transport and communication, commission and contract services, rent and lease of land, buildings, vehicles and machinery, business services, insurance premiums less claims, financial intermediation services.

7.4.2 (Decision O4.2) Escalate opex using the all-industries labour cost (60% weighting) and a producers' price (40%) indices, plus a 0.3% uplift to reflect EDB-specific inflation.

Our detailed submission points are provided in the joint submission with Orion and Vector titled "*Orion Vector and Wellington Electricity submission on cost escalators*".

We agree that non-network opex should be escalated by the proposed application and that the 0.3% uplift is a reasonable cost escalator.

7.5 Opex trend factors – network scale factors

We support the proposed network scale factor framework overall and the Draft Decisions.

However, it is important to note the weaknesses of regression models. A regression model relies on the relationship between input variables and costs being captured in the historic reference set. If the characteristics of a network change, then the historic reference set may not capture new costs, or the relationship it does provide may not be representative of future cost growth.

For example, electrification on the Wellington network is expected to come from existing connections and not new connections. The electrification of transportation, gas use, and process heat will come from providing more electricity to Wellington's existing customers. The associated network cost growth will not be captured from the ICP and line length inputs.

The cost increase will partially be captured from the capex non-network cost driver. However, the size of the forecast demand increase from electrification hasn't been experienced in New Zealand in recent years. The reference data set doesn't have a period of similar growth and isn't likely to accurately capture all the costs needed to support a step change in growth from existing connections.

We support refinements to the model which includes a focus on more recent data as this may better reflect future changes in costs[27]. However, if a trend in expenditure is new then it will still not be captured in any permutation of the reference data set.

We agree that the proposed model will capture cost increases for traditional network growth from operating the network in business-as-usual conditions. However, flexibility mechanisms are needed to provide allowances for new costs not captured in the backwards-looking regulatory mechanisms (mechanisms like the network growth factors). As provided at the start of the opex section of this submission, we think an opex reopener is the best option to provide flexibility to capture critical cost increases (especially for functions that directly impact network quality) in a low-cost regulatory framework.

7.5.1 (Decision O5.1 to O5.6)

We support Draft Decisions O5.1 to O5.6.

[27] Para C175 of the Draft Decision.

7.5.2 (Decision O5.7) Forecast capex based on a constant growth.

We agree with the Draft Decision to use forecast capex in a constant growth. We also agree with using the adjusted capex allowances to set prices.

However, the capex framework recognises that some EDBs will have to apply for reopeners for capex projects that require more scrutiny because of the capex gating mechanism. While a network won't have the allowances for some projects initially, they will likely be awarded additional allowances for essential works in the future. Cost escalations from an increasing capex programme would then be understated in the network growth factors. EDBs would not be able to avoid increases in non-network costs if the reopener capex is for essential works needed to maintain the quality standards.

We think there are two solutions:

1. EDBs could provide their expected programme of reopener capex that could be added to the forecast capex used to calculate the network growth factors. We note that the Commission has asked networks to provide their reopening forecasts.

2. Adjust the non-network growth capex calculation to include capex additions as part of the reopener process.

We think option two provides the best solution as an adjustment would only be made when new allowances are awarded. We also think it's the most low-cost solution as including forecast reopeners into the capex forecast (option 1) would require a degree of scrutiny and additional time and resources. We think updating the network growth factor capex forecast would be low cost because it is a mechanical adjustment to the building blocks inputs.

7.6 Opex trend factors – productivity factors

7.6.1 (Decision O6.1) Apply an opex partial productivity factor of 0%.

We do not support a Partial Productivity Factor (PPF) of 0% because the Draft Decision still misses unavoidable opex costs. The negative PPF provided in the Draft Decision analysis is not necessarily an assumption of negative productivity. A negative PPF could also mean that opex costs for unmeasured outputs is growing faster than the three output measures included in the productivity study – in other words, that the output measures aren't capturing all costs that an efficient and prudent operator needs to operate a distribution network.

We would support the Draft Decision to apply a 0% productivity factor if that gap between opex allowances and costs could be closed. As highlighted at the start of this section the gap can be closed by:

- Adding a new opex reopener or by adjusting the existing 'risk event' reopener to capture unavoidable increases in maintenance costs needed to maintain current quality levels.
- Passing-through insurance costs.

Alternatively, we think a negative productivity factor should be applied to reflect that not all opex costs have been captured. Our preference is to add in the additional flexibility mechanisms because of the limitations of the productivity study and the uncertainty of what the productivity study measures are reflecting.

7.6.1.1 Reframing the productivity study

The Cambridge Economic Policy Associates (CEPA) report, and the NERA report provided in the Big Six network's response to the Productivity Consultation, both recognised the limitations of the study – specifically, that in complex industries like electricity distribution, it's difficult to capture productivity in a small number of output variables. The NERA Paper provided unmeasured outputs not captured in the CEPA study[28].

The NERA study highlighted that if the costs of providing unmeasured outputs are not funded by the regulatory allowances then networks will have to find savings or incur IRIS penalties to fund the new costs. To avoid a large IRIS penalty, EDBs would have to make implicit (implicit because it's not captured in the *measured* productivity improvements) productivity improvements to fund the cost increases. Our submission on productivity in EDB DPP4 reset provided an example of implicit productivity improvements to cover a $0.8m or 74%[29] increase in insurance cost[30].

If DPP4 allowances are set at a level that is not expected to cover all operating costs, like the last reset, the PPF should be reframed as a measure of the gap between allowance and actual costs. Even with the addition of the step changes and additional capex growth factor, we are forecasting an opex shortfall for other cost increases like increases to field services, insurance not captured in the step change, and programme deferrals because of low DPP3 opex allowances. As we highlighted in our submission to the DPP4 Issues Paper, networks are overspending their allowances and incurring IRIS penalties[31]. The recent 'Trends in local lines company performance' report also shows that networks are earning a return below the regulatory WACC for both the DPP2 and part of the DPP3 period[32]. New operating expenses not covered in allowances will be contributing to the low profits. While the proposed new allowances provided in the DPP4 Draft Decision will help close the gap, the Commission recognise that the allowances may not be providing allowances for all costs[33].

28 Section 3.2 of the NERA Paper.
29 WELL's insurance coverage also decreased slightly in 2020.
30 Wellington Electricity, April 2024. Available at https://comcom.govt.nz/__data/assets/pdf_file/0023/351464/Wellington-Electricity-Submission-on-CEPA-EDB-productivity-study-24-April-2024.pdf Page 3
31 Wellington Electricity, December 2023. *Wellington Electricity submission to the DPP Issues Paper,* Available at https://comcom.govt.nz/__data/assets/pdf_file/0033/339792/Wellington-Electricity-DPP4-issues-paper-submission-19-December-2023.pdf Page 26, and Figure 2
32 Commerce Commission, June 2024. *Trends in Local line company performance. Available at* https://comcom.govt.nz/__data/assets/pdf_file/0022/356620/Trends-in-local-lines-company-performance-25-June-2024.pdf Figure 39, Page 52.
33 Table C14 highlights mechanisms that may not be capturing all opex costs.

7.6.2 Considering wider measures of productivity

We note that the Draft Decision balances a range of factors that influence productivity, rather than basing the decision solely on the PPF measure. We think that, on balance, the evidence provided in the Draft Decision favour a negative PPF. We note that the key argument for a positive productivity factor (which we assume offsets the reasons for a negative factor, resulting in an overall neutral 0% productivity factor) is "*the trends in some comparable infrastructure sectors and overseas (and tentatively in the domestic EDB sector)*". As highlighted in the analysis provided in the DPP4 Draft Decision:

- EDB productivity is closely aligned with the overall productivity for the economy in the medium term (2018-2023)[34], the time-period with the most accurate Information Disclosure data and is the most representative of current operating conditions and current expenditure requirements.

- While there is a larger difference in the longer term, the data for the earlier 2008-2013 period was before the Information Disclosure regime was in place which now provides audited cost information that could be relied on.

  In addition, the IRIS mechanism was only introduced in 2018, incentivising networks to spend prudently and to reward cost savings.

- The productivity breakdown of each industry shows that the IT sector is skewing the overall measure. We also note the Draft Decision comment that non-wire solutions could provide productivity improvements like those seen in IT and telecommunications. We agree with the potential, however, it will take time to develop the capability and it's unlikely they will be available at the scale needed to provide meaningful cost savings in the next five years.

- As highlighted in the Draft Decision, much of the improvement in Australian productivity is driven by quality which is not included in New Zealand quality outputs[35]. We think this comparison provides limited value in assessing productivity for New Zealand EDBs.

We also note and agree with the key argument for a negative productivity factor, that "*the future prospect of opex-capex substitution driving higher overall productivity but lower opex productivity*". We would add to this point that networks will also have to invest ahead of the expected benefits, lowering opex productivity even further. The INSTA and the opex step change for LV management will help fund this development. However, networks will have to fund some of the INSTA from opex allowances and for networks like Wellington Electricity, the step change allowance will be used for essential maintenance services not funded by the allowances.

[34] Para C322 form the Draft Decision.
[35] Para C325 of the Draft Decision.

8 Innovation and section 54Q incentives

We agree with the Draft Decisions assessment of the need for an innovation allowance to provide additional incentives to the IRIS mechanism and quality incentives to promote the purpose of Part 4 - 52A (1) (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets. As highlighted in the Draft Decision, non-exempt EDBs may still lack strong enough incentives to innovate or implement non-traditional solutions[36].

We support the proposed framework and agree that it will support EDBs to innovate and will benefit consumers in the long term.

As we highlighted in our DPP4 Issues Paper submission[37], the current Innovation Project Allowance (IPA) places a high-cost burden on the EDB (50% of the cost to innovate) disincentivising networks from projects that they may not expect to be compensated for the investment from the IRIS or quality incentives. The proposed framework provides a better allocation of the risks and rewards of innovation.

We also highlighted in our submission to IM Issues Paper[38] that the IRIS does not allow capex and opex to be substituted across regulatory periods. The Draft Decision recognises that this creates problems with non-traditional solutions (NTS) that are funded by substituting capex allowances via the IRIS if the non-wire solution is in a different regulatory period than the capex the solution is deferring.

The INSTA provides a temporary fix to the issue but is limited to supporting the development of flexibility services and not funding the ongoing operation. A permanent fix to the IRIS issue is still needed. Alternatively, opex allowances could be provided to pay for NTS. As we discussed in our response to the IM Issues Paper, it will be difficult to calculate an accurate allowance for NTS and alternatives like a use-it-or loose-it allowance or a pass-thought may be better solutions.

8.1.1 (Decision U1) Introduce an Innovation and Non-traditional Solutions Allowance (INTSA), capped at 0.6%.

We support the proposed innovation and non-traditional solutions allowance (INSTA) framework in general, including the supporting guidelines. We think the framework is pragmatic and low-cost and provides enough flexibility that it will not stifle innovative ideas.

8.1.1.1 Refining the acceptance criteria

We think that alternative acceptance criteria would better reflect the purpose of the INSTA. On behalf of the ENA, Chapman Tripp reviewed the INSTA criteria that a project "*must be riskier than business as usual (BAU) for the non-exempt EDB such that the non-exempt EDB would not carry out*

[36] Para D7 of the Draft Decision.
[37] Wellington Electricity, December 2023. *DPP4 Issues Paper* Page 65
[38] Wellington Electricity, July 2022. *Submission on IM Review Process and Issues paper and draft Framework paper* p. 14.

the project if it could not recover some or all of the forecast costs of the project from the non-exempt EDB's INTSA".

We agree that the alternative provided in the ENA's submission is better aligned with the intentions of the INSTA. Rather than using criteria that define innovation, the alternative criteria should describe the characteristics of the projects that are not currently incentivised. We think the third eligibility criteria should be replaced with[39]:

(c) either—

(i) the financial benefits to the EDB of the project or programme are uncertain; or
(ii) there is a material risk that the project or programme may not result in:
(a) any financial benefit to the EDB; or
(b) a sufficient financial benefit to justify the investment.

We think this alternative criteria captures the idea of innovation as an activity that has inherently uncertain benefits. The alternative definition simplifies the criteria and avoids having to define the 'Risker than BAU' criteria which is difficult and potentially subjective to interpret. The Commission notes that this criteria does have a subjective element to it[40].

8.1.1.2 Clarifying what's innovative and whether this includes staged development

We think there needs to be guidance and examples about whether INSTA allowances will be awarded for similar projects testing a different component of a new capability or the same or similar trial (like a NTS trial) on a different part of the network. We note the Commission's comment in paragraph D44.

"*However, our intention is that once a project has been successfully delivered with INTSA support, the EDB will have the confidence to roll the technology or process out across their business, as incentivised by the DPP's baseline settings. At that point, the project would be unlikely to be 'riskier than BAU*".

This interpretation of the INSTA criteria suggests that an INSTA allowance may not be offered for NTS once they have been successfully trialed. As already mentioned, the expectation is that the INSTA will be used to fill in any IRIS shortfalls if a network needs to fund a flexibility service from substituting capex and opex but cannot because the service is deferring capex in a different regulatory period (and that benefits of that deferral is not captured by the IRIS). Interpreting the 'risker than BAU' criteria as described in paragraph D44 will disincentivise EDBs to consider some NTS because they will not always funded by the regulatory model, even when it's in the best interest of consumers.

Another example of where the 'riskier than BAU' criteria could be subjectively interpreted is for the staged development and testing of a new capability or technology. For example, the development

[39] Refer to the ENAs Draft DPP4 submission and the supporting advice from Chapman Tripp.
[40] Para D44 from the Draft Decision.

of flexibility services into services that has the scale to provide a viable alternative to building traditional capacity could be done by multiple small projects. This would enable an EDBs innovation programme to fit in with other EDB programmes and to quickly pivot and adjust to the results of earlier programmes. We believe that there could be subjectivity in deciding whether the next project in the development path is still 'riskier than BAU'. If the allowances are not awarded then a network may stop the development, stranding further development. In practice, we think that this type of decision will be less subjective because breaking the programme up into multiple small projects will reduce the project value and the risk to the customer of awarding the allowances. However, it does provide another example of potential difficulties in applying the 'riskier than BAU' principles.

We think these challenges can be mitigated by the alternative criteria provided in the previous section and by providing examples in the guidelines.

8.1.1.3 The INSTA framework

Generally, we would support an ex-post approval with guidelines to reduce the risk of an application not being approved and to avoid having to plan for an uncertain (in terms of timing) approval process. However, given the large available pool and potential higher value of an innovation project, we think ex-ante approval makes sense. We think the supporting 'Project Eligibility Assessment' and guidelines will also speed up the approval process. This is a practice we would like to see applied to other regulatory processes like reopeners.

We would prefer to have the ability to recover innovation costs annually for multi-year projects but agree that the complexities of adding a claw-back would overly complicate the mechanism.

We agree with the approach taken to set the 75%-100% cap and the logic around having to provide additional evidence to support a recovery greater than the 75% minimum. We think the guidelines will be useful to guide EDBs about what additional evidence will be required.

We agree with the 0.6% overall cap and with the logic used to set it – primarily that flexibility in New Zealand is immature and networks will need to make significant investments before NTS are at the scale needed to provide an alternative to building traditional new capacity.

We strongly support the requirement to share what we have learned. We agree with providing a detailed close-out report. We also think that networks have a wider obligation to present back to the industry the findings of the project. The ENA and EEA provide great forums for sharing what we have learned. While it's not necessary to create a regulatory obligation to do this, it should be expected by our customers and other networks to avoid duplication and to speed up the dissemination of the project results.

8.1.1.4 Quality interruptions

See section 9.4.7.

8.1.1.5 Highly ambitious option

We would support adding this ambitious option to the INSTA regime. This would provide an important tool for the development of a step change in distribution services that the proposed

INSTA could not fund because of the 0.6% of maximum allowable revenue (MAR) funding limit. Examples of the types of projects this could enable include:

- The development of a Distribution System Operator function
- The development of a central flexibility trading platform
- The development of real-time pricing for distribution constraints, and the development of a dynamic 'spot price' and trading function for clearing those constraints.

Large projects like these would benefit most networks and could provide value to other stakeholders. The mechanism would need to be flexible enough to encourage other value streams and support joint programmes developed by multiple networks.

We support the proposed risk-sharing approach in theory and agree that there needs to be flexibility to account for the range of benefits and value streams. A strong and robust business case will be an important tool for ensuring a sensible balance between the project risk and potential rewards for both the EDB and the consumers. There will also need to be an understanding that if an EDB takes on more of the risk, they should expect a greater potential return.

We also agree that this shouldn't be limited to a CPP. That would limit this type of bold development to a handful of networks that are already applying for a CPP. As highlighted in the paper, a network would not apply for a CPP just for these types of innovation projects[41].

8.1.2 (Decision U2 and U3) Incentivise energy efficiency and demand-side management incentives through the INTSA.

We support the Draft Decision and agree that the proposed INSTA mechanism would capture these types of projects.

Changing the 'risker than BAU' criteria to the alternative ENA criteria would make the application of the INSTA to these types of projects even clearer. The alternative criteria would remove any subjectivity about whether to approve projects that an EDB is not fully funded to provide and would benefit customers but may not be risky because they involve known technology and processes.

9 Quality

The planned quality standards and incentives will not support the increase in capex allowances that have been approved and the expected reopeners for customer projects that cannot be delayed until later price/quality paths. Specifically:

1. The step change in capex awarded by the draft decision plus the expected reopeners require a planned SAIDI budget that is above the planned SAIDI limit – delivering the capex programme is likely to result in a quality breach.

[41] Para D127 of the Draft Decision.

2. The planned capex incentives mean we will be penalised for delivering the capex programme. This means the price path is being set at a level where we cannot expect to earn a normal return – the principle of financial capital maintenance will not be maintained.

We note that the Draft Decision suggests making a quality reopener application for a different planned SAIDI quality path to support the capex programme. The quality reopener requires that we consult with customers about the new quality path, which essentially means consulting about the capex programme it supports. Capex is set using a different process independent of a quality reopener and, therefore, the customer consultation will provide no value. The high cost of customer consultation is also not consistent with a low-cost DPP.

We would be comfortable making a quality reopener if we could exclude the customer consultation element.

9.1 Quality standards

9.1.1 (Decision QS1) Maintain separate standards for planned and unplanned SAIDI and SAIFI.

We agree that separate standards should apply for planned and unplanned outages.

9.1.2 (Decision QS2) Retain annual unplanned reliability standards for SAIDI and SAIFI.

We support the Draft Decision to retain annual reliability standards, subject to the 2.0 standard deviation limit (QS3) and major event day normalisation (N2) also being retained.

9.1.3 (Decision QS3) Retain the 2.0 standard deviation buffer for setting the unplanned interruptions reliability standards.

We support the Draft Decision to retain the 2.0 standard deviation limit. We agree that it appears to help reduce the risk of false positive breaches being caused by the random variability in outages.

9.1.4 (Decision QS4) Maintain regulatory period length standard for planned SAIDI and SAIFI.

In the absence of the planned quality standard linked to the size of the EDB's work programme, we support the Draft Decision to retain the regulatory period length for the planned SAIDI and SAIFI standard. The Draft Decision gives EDBs flexibility to phase their planned quality 'budget' in whichever way best suits the efficient delivery of work, rather than the reverse of having the timing of work be influenced by compliance with the quality standard, with the potential for negative consequences on unplanned quality.

9.1.5 (Decision QS5) Change the planned reliability buffer for the planned interruptions reliability standard to be a 100% uplift on the historic average, capped at a +/- 10% movement from the current standard.

Planned outages have a direct relationship to a network's capex programme. The replacement or upgrade of electrical equipment often requires parts of the network to be de-energized so the works can be completed safely and cost-effectively. Networks are awarded a planned outage budget so they can complete their maintenance and capital work plans. The larger the work plan, the larger the planned outage budget will be needed. Planned outages are not a function of historic outages unless the size and type of work programmes haven't changed.

This also means that the planned quality budget has an indirect relationship with unplanned outages in the longer term. If a network cannot complete its maintenance and capital works, then that will impact the on-going performance of the network and its future reliability.

Setting the planned limit at a 100% increase on the historic average, with a maximum movement between periods of 10%, may not provide EDBs with the quality budgets needed to deliver their capex programmes. Reducing the cap does not incentivise EDBs to invest and does not support the Purpose of Part 4[42].

The expenditure allowances in DPP4 will include a significant quantity of work related to ensuring that networks have the capacity to support customers' decarbonisation projects without increasing the risk of unplanned outages. A backwards-looking approach to setting the planned outage limits has no relationship to the investment required, and the risk of a breach that this creates will act as a disincentive that could potentially lead to an unfortunate situation of EDBs not being in a position to deliver customer-initiated work due to an unrealistic planned outage limit.

We will need to apply for reopeners for additional capex to deliver capex works that cannot be deferred until the next regulatory period or until an alternative price path is approved. We developed a planned SAIDI and SAIFI forecast for our 2024 AMP that was based on our historical planned outage efficiency (i.e. planned SAIDI minutes per million dollars of expenditure) across different work types. A description of the model is provided in 9.1.5.1.

Figure 7 provides a breakdown of our planned SAIDI forecasts and compares the forecast to the Draft compliance limits. The Draft Decision provides little headroom to deliver our awarded capex and we would breach once reopeners are added. We can deliver our capex and maintenance funded by the Draft Decision with a small buffer of 13.61 SAIDI minutes across the regulatory period for programme changes or reopeners. Delivering our reopener programme would mean we would breach by 5.39 SAIDI minutes.

Figure 7 – forecast planned SAIDI requirements

Year ending 31 March	2026	2027	2028	2029	2030	Total for DPP4	Compliance Limit	Headroom
Maintenance	4.37	4.37	4.37	4.37	4.37	21.85		
DPP Construction	8.88	8.85	8.11	7.73	7.63	41.2		
Total SAIDI to support Draft Decision	13.25	13.22	12.48	12.1	12	63.05	76.66	13.61
Reopener Construction	0	4.75	4.75	4.75	4.75	19		

[42] Part 4 52A (1) (a) of the Commerce Act 1986.

Year ending 31 March	2026	2027	2028	2029	2030	Total for DPP4	Compliance Limit	Headroom
Total SAIDI	13.25	17.97	17.23	16.85	16.75	82.05	76.66	-5.39

The planned limit must be set at a level that enables EDBs to deliver the approved work programme. EDBs must still be prudent and efficient in their use of planned outages, and this is captured by the Quality Incentive Scheme.

Basing the planned reliability limit on an uplift from a target set under such a scheme would provide a realistic baseline for EDBs to be measured on, that is explicitly linked to historical performance and the approved future allowances under the price path.

9.1.5.1 Alternative SAIDI forecasting method

Planned outages arise from either maintenance of existing assets (opex), or construction of new assets (capex). Our forecast approach calculates SAIDI efficiency levels in minutes per million dollars for opex and capex.

Cost categories that impact planned SAIDI include:

1. Routine and Corrective Maintenance and Inspection opex categories
2. Quality of Supply, Relocation, and Distribution Lines, Substations, Switchgear, and Other Network Assets for both System Growth and Asset Renewal capex categories

Sub-transmission, zone substation, and distribution cable capex is excluded because replacement of these can often be undertaken without incurring planned outages.

The last three information disclosure years have been used to assess the baseline. These are then inflated to 2024 dollars to allow a consistent comparison.

Figure 8 – Calculation of the SAIDI efficiency levels

Regulatory years	RY 2020/21	RY 2021/22	RY 2022/23	Average
Planned SAIDI Minutes	8.43	9.30	13.11	
- Maintenance SAIDI	*3.60*	*2.99*	*3.95*	
- Construction SAIDI	*4.83*	*6.31*	*9.16*	
Routine and corrective maintenance and inspection Opex ($k)	7,511	8,280	8,944	
Relevant Network Capex ($k)	17,150	18,339	25,508	
Inflation relative to 2024 dollars	0.776994	0.846265	0.948319	
Opex SAIDI Efficiency (minutes per $m)	0.37	0.31	0.42	**0.37**

Regulatory years	RY 2020/21	RY 2021/22	RY 2022/23	Average
Capex SAIDI Efficiency (minutes per $m)	0.22	0.29	0.34	**0.28**

We have assumed that the target capex efficiency is 0.3 SAIDI minutes per million dollars of relevant expenditure. It is also assumed that planned CAIDI will remain constant throughout the period (i.e. SAIFI is proportional to SAIDI).

After revising our DPP4 expenditure to align with allowances, plus expected reopeners, we can forecast our planned SAIDI requirements. This is summarised in Figure 7.

9.1.6 (Decision QS6) De-weight the impact of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards.

We question the misalignment between the 50% weighting of notified interruptions under the quality standard, against the 38% weighting they are given under the incentive scheme. The weighting for notified interruptions should be consistent across the two measures.

9.1.7 (Decision QS7) Retain SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified.

We support the Draft Decision. The extreme event standard is an important companion to the major event normalization methodology, to serve customer interests through the focus on assessing and mitigating the risk posed by high risk, low probability events, that would otherwise have their impact normalised out of the quality standard.

We do note, however, that the terms “severe storms”, “severe wind”, and “severe rain”, which are used in the definition of natural disasters that are excluded from the extreme event standard, are themselves not defined, so EDBs do not have clarity about whether a particular storm would be considered by the Commission to be a breach of the standard.

9.1.8 (Decision QS8) Retain enhanced automatic reporting following a breach of a quality standard.

We support the Draft Decision. The current reporting obligations are generally appropriate.

9.1.9 (Decision QS9) No new quality measures are introduced as part of the quality standards applying in DPP4.

We support the Draft Decision. There are a number of aspects of quality beyond SAIDI and SAIFI that matter to customers (for example low voltage reliability), however, at this time there is insufficient data to allow reasonable quality measures to be set.

9.1.10 (Decision QS10) Set interruptions quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP.

No comment.

9.1.11 (Decision QS11) Retain the requirement for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs.

No opinion.

9.2 Quality incentives

9.2.1 (Decision QIS1) Retain the revenue-linked quality incentive scheme for planned and unplanned SAIDI. SAIFI is excluded.

We support the draft decision to retain a QIS for planned and unplanned SAIDI.

Excluding SAIFI from the QIS favours quality improvements that reduce outage duration, as opposed to minimisation of customers affected. This means that some reliability improvements that have a greater impact on SAIFI than on SAIDI (for example those that reduce the risk of short duration 33kV outages) are not rewarded under the QIS. However, we agree that SAIDI and SAIFI are generally aligned, that a 50/50 weighting of SAIDI and SAIFI under the QIS would over-incentivise SAIFI, and a SAIDI-only incentive scheme will largely capture changes in both frequency and duration.

9.2.2 (Decision QIS2) Unplanned incentive rates are informed by the value of lost load (VOLL), discounted by (1-IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VOLL set at $35,374r/MWh.

We support the method of inflating the 2004 VoLL to establish a baseline for the value of a SAIDI minute under the QIS.

It is interesting to consider the QIS in the context of the potential for EDBs to procure non-traditional solutions (NTS) from third parties to support planned outages. It is common for EDBs to use temporary diesel generation to reduce the SAIDI incurred from planned outages, however as flexibility markets develop it may be possible for this service to be procured from customers. The proposed incentive rate for avoiding a planned outage is approximately 6.9c/kWh.[43] If EDBs treat the incentive as keeping themselves whole for the IRIS penalty resulting from the expenditure in procuring the service, this sets the value of the service at 20.7c/kWh. This is a useful figure that provides the industry with an early understanding of the value that NTS can provide to EDBs in a specific context.

Importantly, EDBs will only be fairly incentivised to consider NTS to improve quality if the planned allowance is set at a level where the EDBs can reasonably expect to deliver their capex work programme without incurring penalties. As discussed in our response to QS5, the planned quality allowance will not reflect the increase in capex. Rather than reward networks for finding effective ways to improve quality, they will be penalised less than they would have been without the service (which does not meet the purpose of Part 4 because an EDB cannot expect to earn a normal profit

[43] E268.3 of the Draft Decision

and is therefore not incentivised to invest). This has strong parallels with the 'revealed cost' approach to incentivizing opex cost savings using the IRIS[44].

The additional 10% reduction in incentive rates due to the effect of the quality standards appears to be arbitrary, as we have not seen any analysis that justifies this figure.

9.2.3 (Decision QIS3) Planned incentive rates are reduced by 35% relative to the unplanned incentive rate.

We support the Draft Decision to reduce the planned incentive rate by 35% relative to the unplanned rate. This ratio is consistent with the relative value to customers of planned and unplanned outages as identified in a 2012 VoLL study for Ofgem[45].

9.2.4 (Decision QIS4) Planned 'notified' interruptions are reduced by 75% relative to the unplanned incentive rate to reflect less inconvenience to consumers.

We question the mismatch between the value of notified interruptions under the QIS relative to the compliance measures. If the financial cost to a customer of a notified outage is 38% of that of a standard planned outage (as indicated by their relative values under the QIS), then that proportion should carry through into the compliance scheme. The two aspects of the quality path, compliance and incentives, are two aspects of the same measure (impact on customers), and therefore must be consistent.

9.2.5 (Decision QIS5) Incentives are revenue-neutral at the average of the reference period, also known as the target.

Planned SAIDI and SAIFI are a reflection of expenditure, and a backwards-looking target takes no account of the investment required to support the energy transition. We are surprised that EDBs have in general not forecast that the delivery of the uplift in capex for DPP4 (a 35% increase from DPP3 is indicated in the Draft Determination) would not result in an increase in outages[46]. We wonder if this is a reflection of current AMP practices and because EDBs did not expect the forecast to be used to set the quality targets.

An increase in planned SAIDI and SAIFI that is the direct result of work programmes that deliver customer decarbonisation projects is not 'material deterioration'. Planned work in this context is ensuring that new capacity is built to supply the increased demand, without an erosion of security of supply which would lead to an increase in unplanned outages.

We agree that it is essential for an incentive scheme to value planned SAIDI, as this drives the EDB to be efficient in its use of planned outages. However, setting the revenue-neutral point based on historical work programmes instead of relating it to the work that customers expect us to deliver over the next five years in order to maintain sufficient network capacity and therefore unplanned

---

[44] D10 from the DPP4 Issues Paper
[45] https://www.ofgem.gov.uk/sites/default/files/docs/2012/09/riioed1conresvoll.pdf
[46] Table E19 of the Draft Decision

quality standards, results in a permanent penalty. It also increases the risk of a planned quality standard breach potentially leading EDBs to trade off planned SAIDI with the risk of a future increase in unplanned outages.

We developed a planned SAIDI and SAIFI forecast for our 2024 AMP that was based on our historical planned outage efficiency across different work types (described in section 9.1.5.1). Setting the planned outage targets based on such a scheme would provide a realistic baseline for EDBs to be measured on, that is explicitly linked to historical performance and the approved future allowances under the price path, retaining an incentive to deliver improved outage efficiency through the QIS.

Under the current method, historic planned outage levels would unreasonably punish EDBs for delivering the work needed to maintain unplanned performance in the future. Our alternative model shows that if we deliver the maintenance and capex that is funded by the Draft Decision and we are awarded reopeners for capex projects we can't defer, we will be penalised $800k during the regulatory period.

9.2.6 (Decision QIS6) The SAIDI caps (which determine maximum losses) are set equal to the SAIDI limits for planned and unplanned SAIDI.

We support the Draft Decision.

9.2.7 (Decision QIS7) The SAIDI collars (which determine maximum gains) are set at 0 for unplanned and planned SAIDI.

We support the Draft Decision.

9.2.8 (Decision QIS8) Cap revenue at risk at 2% of actual net allowable revenue.

We support the Draft Decision.

9.2.9 (Decision QI9) Do not implement any new incentive schemes.

We support the Draft Decision.

9.2.10 (Decision QIS10) Do not make an explicit adjustment to match the duration of retention benefits between EDBs and consumers.

We agree that there is a mismatch in the duration of benefits for increased SAIDI efficiency. The EDB benefits from increased headroom to the SAIDI limit, which endures until the next reset if it reduces planned SAIDI or is an intervention that provides ongoing unplanned SAIDI reductions (e.g. worst performing feeder improvement projects), with only some instances providing that benefit for just one year (e.g. the use of temporary generation to support an unplanned outage). In all cases, customers benefit from a reduction in minutes without supply, and these benefits endure beyond the next reset as they are baked into the reference period.

We also agree with the Draft Decision that the value of adjusting the QIS retention rate to reflect these differences in duration is not worth the complexity of doing so.

The current approach of applying the same retention rate as expenditure is a pure approach that allows the EDB to undertake a direct cost-quality trade-off assessment, that ensures customers are not over-paying relative to the value to them of reliability improvements, while also keeping the EDB whole for that investment.

9.3 Normalisation

9.3.1 (Decision N1) Normalisation only applies to unplanned interruptions, which are the only initiators of a major event day.

We support DPP4 staying consistent with the normalisation approach used in DPP3.

9.3.2 (Decision N2) Retain the normalisation approach used in DPP3

We support retaining the DPP3 normalisation approach. This appears to be effective at evening out the impact of an appropriate number of major events per year.

9.3.3 (Decision N3) SAIDI and SAIFI major events are triggered independently.

We support the Draft Decision to have SAIDI and SAIFI events triggered independently.

9.3.4 (Decision N4) Set a higher boundary for very small EDBs.

No comment.

9.3.5 (Decision N5) Retain additional reporting by EDBs for each unplanned major event in its compliance statement consistent with DPP3.

We support the Draft Decision. The current reporting obligations are generally appropriate and reflect a summary of the analysis of major events that EDBs should already be undertaking as good industry practice.

9.4 Reference period

9.4.1 (Decision RP1) Use a 10-year reference period from 1 April 2013 to 31 March 2023 to inform the parameters for unplanned interruptions reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination.

We support the continued use of a 10-year reference period for unplanned outages, as this provides a stable baseline of historical performance against which to measure material deterioration.

9.4.2 (Decision RP2) Apply a reference period for planned interruptions of 2017 – 2023 for the draft decision, extended to 2017 – 2024 for the final decision.

We agree that shortening the planned outage reference period from 10 years to seven years allows the targets and limits to reflect the impact of changes to work practices as indicated by Figures E4 and E5 in the Reasons Paper. We would also support reducing the period to five years in line with the EEA recommended method.

However, the setting of targets and limits based on a backwards-looking reference period is not appropriate for the increase in investment that EDBs will be required to deliver, as previously discussed in our response to QIS5.

9.4.3 (Decision RP3) Retain the cap on inter-period movement, ±5% for unplanned interruptions for both the SAIDI and SAIFI unplanned target and also apply this to the SAIDI and SAIFI unplanned limits.

We agree with retaining a ±5% cap on movement in unplanned targets and limits as a means of preventing a deterioration in network performance leading to looser targets, and conversely preventing a period of better than average performance producing an unreasonably low sinking lid on the reliability limits.

9.4.4 (Decision RP4) Make no explicit step changes to reliability targets or incentives.

Decision RP6 to require that EDBs record successive interruptions in a manner consistent with their historical practice is preferable to applying a step change to the reference dataset and requiring EDBs to change their recording practices.

We have discussed in QIS5 the need for planned quality targets to become reflective of the forecast work programme, rather than being backwards looking.

9.4.5 (Decision RP5) Make no explicit adjustments for instances of non-compliance contained within the unplanned interruption reference period dataset.

We support the Draft Decision to not make adjustments to the unplanned reference dataset for historical instances of non-compliance. The interlinked nature of the limits and major event normalisation methodology would make the adjustment of the dataset unnecessarily complex, compared to the alternative of relying on the averaging of 10 years of data to balance out the impact of the non-compliance, with the 10% inter-period cap kicking in as a last resort. Excluding years of poor performance from the dataset would be likely to lower the boundary values as well as the limit, resulting in a greater than expected number of days being normalised in future, which could mask a deterioration in performance.

9.4.6 (Decision RP6) EDBs must record successive interruptions on the same basis they employed in responding to the s 53ZD notice.

We agree with the requirement for EDBs to continue recording successive interruptions on a consistent basis to the way that they have historically been recorded. Since EDB SAIFI quality paths are set based on the EDBs own historical performance, with no reference to the performance of other EDBs, there is no benefit in manipulating the historical dataset to align the approach between EDBs.

As is highlighted in the Draft Decision[47], we think the best solution is to allow EDBs to choose which method best incentivises the level of quality that customers on their networks want. On the Wellington network that is to record successive outages as a single outage as it incentivises restoring power as quickly as possible by sectionalising the network following a fault.

[47] Para E463 of the Draft Decision.

9.4.7 (Decision RP7) Interruptions directly associated with an approved INTSA project are excluded for calculation of SAIDI and SAIFI values up to a cap of 0.5% of the respective SAIDI and SAIFI limit.

We support excluding SAIDI and SAIFI associated with INTSA projects from the quality standards.

However, the cap of 0.5% of the limits is too low (e.g. less than 0.19 unplanned SAIDI minutes for Wellington Electricity) to be significant in providing EBDs assurance that their participation in innovation projects will not lead to an adverse quality path outcome. We prefer an alternative approach of the SAIDI and SAIFI risk being assessed as part of the INTSA application process and, on that basis, approving caps that reflect the scope of the project and the risk it carries.

This also formalises the good practice of quantifying any reliability risk associated with NTS. The risks of using NTS is an important learning area that should be captured in the INSTA reporting and shared with the industry.

10 Revenue path

10.1 Price path

10.1.1 (Decision P1) Set starting prices based on the current and projected profitability of each supplier using a building blocks allowable revenue (BBAR) model.

We support the Draft Decision. We agree that rolling over the DPP3 prices would not capture cost changes.

We also support setting the revenue path with the expectation that an EDB will recover their costs within the regulatory period. We agree that deferring revenue into the next regulatory period could create financeability issues and disincentivise EDBs to invest (and would not promote the purpose of Part 4 52(A) (1) (a)).

As highlighted by Oxera, in the Big Six submission to the DPP4 Financeability Issues Paper[48], deferring revenue could also create investability issues. Investors in infrastructure assets do so for modest but consistent returns. Deferring revenue could impact the ability of a network to pay regular dividends and, therefore, to retain and attract equity.

The Dunedin City Council have been considering whether to sell the Aurora network. The recent public consultation suggested that deferred dividends could be a contributing factor, asking if they should sell the electricity network so they could invest in other assets that would provide more immediate returns[49].

[48] Oxera, 2024. https://comcom.govt.nz/__data/assets/pdf_file/0027/347517/Big-6-EDBs-financeability-issues-paper-submission-15-March-2024.pdf
[49] Aurora Energy Proposal - Dunedin City Council

10.1.2 (Decision P2) Set a default rate of change relative to CPI (X-factor) of 0%.

We continue to support this decision.

10.1.3 (Decision P3) Set alternative X-factors such that, in most cases, initial price shock is limited to 20% in real per ICP. terms, and the change between years within the regulatory period to 10% (based on the price shock and notional financeability assessments).

We support the Draft Decision which applies the ‘medium’ smoothing option. We agree that the ‘no smoothing’ option creates a price shock that is too large. We also agree with the reasons not to apply the ‘uniform smoothing’, including providing some headroom for reopeners. As we highlight in section 6.1, the high-level capex cap will mean that networks will have to apply for additional allowances or the probability of more outages will increase, potentially worsening network quality.

10.1.4 (Decision P4) Assess price shocks on a real revenue per ICP basis, incorporating wash-ups and IRIS.

We support the Draft Decision as it achieves the result of balancing affordability with providing a price path that a reasonable and prudent network can finance.

However, it is important to note the ‘*real revenue per ICP’* measure is not a correct measure of affordability. The measure will not capture volume increases as consumers shift from using fossil fuels to electricity. Electrification will increase electricity bills but those customers will see a comparable or greater decrease in their other energy bills. The Boston Consulting ‘Future is Electric’ study shows that while electricity bills are expected to increase, household affordability will improve as customers use electricity that is less expensive than other fuels[50].

However, we agree that in the early stages of the energy transition, a less volatile measure will be more appropriate. So, whilst the Draft Decision could be improved to better capture affordability, we think it does provide the right outcome.

10.1.5 (Decision P5) Assess notional financeability using FFO/Debt and Debt/EBITDA ratios.

We support and commend the Commission for developing a financeability check. Coupled with the starting position of setting prices with the expectation that an EDB will recover all of the revenue within a regulatory period, it will help ensure a network’s debt costs are aligned with WACC’s cost of debt.

We also support the financeability check itself. We think it is practical and transparent, and should correctly capture whether regulatory cashflows will support a BBB+ credit rating.

We understand that it’s a sense check rather than a test, such as those applied in other judications. While we would have preferred a ‘test’ because it provides more confidence that the price path will

[50] Boston Consulting Group, 2022. ‘Future is Electric’, Available at https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf Exhibit 53 and Exhibit 53

support a network's debt funding. The transparency provided with the Draft Decision will quickly highlight financeability issues that can then be raised with the Commission (assuming the Commission hasn't already addressed them).

10.1.5.1 Importance of financeability

In paragraph G14, the Commission commented on the results of the financeability sense check, saying the results 'do not support the view of a widespread financeability problem for DPP4'. The comments seem to infer that financeability issues can't exist and that it's not important to check for any financeability issues.

The reason the check shows there are no significant financeability issues is because of the Draft Decision to set a price path that should allow all revenues to be recovered within the regulatory period. If this decision had not been made, then there would have likely been financeability issues.

Submissions called for a financeability test while the Commission was considering how to smooth the large DPP4 year-one price increase. The Issues Paper did not propose a price path and as part of the submission process, networks tested the different scenarios. Those scenarios showed there could be 'widespread financeability problems' if a different smoothing scenario was chosen[51]. Other jurisdictions have added financeability tests into their regulatory frameworks also recognising the potential issue.

10.1.5.2 Investability

We also think financeability is a component of the regulatory model which will evolve like it has in other jurisdictions. For example, in the United Kingdom, the tests have been expanded to include investability, recognising that the regulatory model must also support the dividend expectations of its equity investors.

We note the Commission does not see a need for an investability test because other infrastructure investors have forgone dividends at times of significant investment. This view is counter to the empirical evidence in the Oxera report provided by the Big 6 networks in response to the DPP4 Financeability Issues Paper consultation[52]. The report concluded that "*…in practice, investors may not be indifferent between receiving a dividend and reinvesting in the company, i.e. they may be affected by the timing of cash flows in relation to firms' dividend distribution policy*".

10.2 IRIS

10.2.1 (Decision I1) IRIS retention rate for capex is equivalent to the opex rate.

We support the Draft Decision to maintain equal IRIS incentive rates between capex and opex, to provide financial neutrality for spending decisions. As highlighted in the Draft Decision, EDBs should

[51] Frontier Economics, July 2019. https://comcom.govt.nz/__data/assets/pdf_file/0015/323106/27Big-627-EDBs-Frontier-Economics_-A-review-of-the-limit-on-EDB-price-increases-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf

52 Oxera, March 2024. *Big-6-EDBs-financeability-issues-paper-submission*

not be disincentivised from implementing an NTS if it is more efficient than a traditional capex solution that a network has had allowances provided for.

10.2.2 (Decision I2) Determine IRIS opex and capex forecasts in real terms (inflated by CPI).

We continue to support the IM Decision to set IRIS opex and capex forecasts in real terms.

10.3 Revenue Path – washup

10.3.1 (Decision R1.1) Apply a revenue cap with wash-up as the form of control.

We continue to support the IM Decision to apply a revenue cap with a washup.

10.3.2 (Decision R1.2) Forecast CPI based on the four-quarter average change in CPI between the first year of the regulatory period and the current year.

We support the Draft Decision.

10.3.3 (Decision R1.3) Apply a 90% "voluntary undercharging" limit (or an alternative in some cases).

Our ownership model means it is unlikely that we would voluntarily undercharge.

We are not well placed to provide feedback on this decision.

10.3.4 (Decision R1.4 to R1.5)

We support the Draft Decision.

10.4 Revenue Path – smoothing limits

10.4.1 (Decision R2.1) Apply the revenue smoothing limit based on forecast net allowable revenue for the current year and CPI-adjusted recoverable costs from the prior year.

We support using the most up-to-date CPI data and expressing the Revenue Smoothing Limit (RSL) in real terms. This approach is consistent with the intent of the smoothing mechanisms – to limit any real price shocks. A nominal RSL would include inflation which (at least in the medium term) should be netted off with a corresponding increase in consumer wages and salaries.

We also support using the forecast net allowable revenue for the current year and CPI-adjusted recoverable costs from the prior year which will focus the smoothing mechanism on movements in recoverable costs. We agree that the alternative options would either not smooth revenue or could create a build-up in the washup that couldn’t be realised before the end of the regulatory period.

10.4.2 (Decision R2.2) Apply a revenue smoothing limit of 10%.

We support the revenue smoothing limit of 10% because it excludes pass-through costs and inflation.

We are comfortable with the 10% limit not being adjusted for volume changes because the 10% limit is an implicit/high-level proxy of a price shock and is not an explicit estimation of when price increases might be unaffordable.

Any accurate measure of a price increase should adjust for volume increases to reflect consumers shifting their energy use from fossil fuels to electricity. An increase in electricity bills would not reflect a price shock because other household bills would have a corresponding or greater decrease.

10.5 Revenue Path – operation

10.5.1 (Decision R3.1) Implement the revenue wash-up by specifying a re-run of the DPP4 financial model.

No comment.

10.5.2 (Decision R3.2 to R3.4)

We support these revenue path Draft Decisions.

10.6 Other Matters

10.6.1 (Decision X1) Retain the current five-year regulatory period length.

We support the Draft Decision to keep the five-year regulatory period for the reasons provided.

We do not think a shorter regulatory period provides a better solution than using reopeners to address investment uncertainty and the capex step change. Increasing the capex gate to 135% will help reduce the number of reopener applications to a more manageable level.

Additional flexibility mechanisms are also still needed, including a reopener to capture unavoidable increases in opex costs that are needed to maintain the quality standards (discussed in sections 7.1.1.1 and 7.1.1.3).

10.6.2 (Decision X3) Retain the CPP application timings set for DPP3.

We support the Draft Decision. The proposed timeframes are reasonable.

10.7 Other inputs to the financial model

10.7.1 (Decision M1 to M5) Weighted average cost of capital (WACC) of 7.37%. [This will be updated for the final decision.]

We support the inputs into the financial model.