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Default price-quality paths for electricity distribution businesses from 1 April 2025 – Final decision

Reasons paper

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Commerce Commission

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Foreword

On behalf of the Commerce Commission, I am pleased to present our final decision on revenue limits and quality standards in the 2025-2030 electricity distribution default price-quality path (DPP4).

In making our decision, we have had the long-term interests of consumers at the forefront of our minds. Consumers use the electricity network every day, and they should be able to have confidence that this critical infrastructure is reliable and represents value for money. In practice, this means our decision should support electricity distribution businesses (EDBs) to make the right investment, at the right time and at the right cost, to provide services at a quality that reflects the demands of their customers.

While the aim of the Commission's regulatory regime is enduring, each DPP brings its own challenges. Interest rates and inflation have risen since we last set revenues, growth in demand for electricity is accelerating, and some EDBs expect to invest more in replacements and renewal of assets due to the age of their network. Our decision allows for a significant increase in total revenue to enable EDBs to meet these challenges.

This is a material change from previous decisions, which were made in the context of relatively flat demand and steady investment, as well as lower inflation and financing costs. Recently, consumers have benefited from the relatively low interest rate from the 2020-2025 period. The current economic and sector context means that electricity bills will rise in DPP4, to meet cost pressure and enable investment that will benefit consumers in the long term.

We understand higher electricity bills for consumers are coming at a time when many are struggling with rising costs across their households and businesses. We have sought to soften the immediate impact of the rise in prices by spreading some of it over five years. We cannot avoid or defer the increases altogether though, as ongoing efficient investment in critical infrastructure is vital to avoid a decline in reliability and higher future costs.

Our decision allows for less expenditure than EDBs forecast in their public planning documents for the coming period. We expect EDBs to work effectively within our regime to efficiently deliver services, maximise the use of existing network capacity, and prioritise spending to meet consumer demands. This means that we will take a strong interest in steps that EDBs are taking to innovate and to promote the efficient use of their networks, including managing or incentivising load shifting. Where further expenditure is unavoidable, EDBs can apply to us for adjustments to their allowances.

The default price-quality path is part of a wider regulatory toolkit that the Commission uses to promote consumers' interests given the range of circumstances in local areas. In the 2023 Input Methodologies Review, we recognised the value of flexibility in the scope of reopeners given uncertainty about the scale and speed of changes in demand and technology. We are continuing to work on the practical implementation of reopeners to ensure they work as intended.

I would like to emphasise that while we expect to see greater use of reopeners in future, their use must promote the long-term interests of consumers. Reopeners are not expected to cover all circumstances, and we expect an EDB to apply for a customised price-quality path if it experiences significant changes to its particular circumstances.

Finally, I would like to take this opportunity to thank everyone who has contributed to the process to set the DPP over the past 18 months. Our final decision reflects extensive consultation, and we received valuable insights from a wide variety of stakeholders. I appreciate the effort it takes to participate in consultation and am grateful for all those who continue to engage with us to help make New Zealanders better off.

Vhari McWha
Commissioner

Executive summary

Purpose of the paper

X1 This paper sets out final decisions on the default price-quality path (DPP) for non-exempt electricity distribution businesses (EDBs) that will apply from 1 April 2025 (DPP4).[1] This summary sets out:

X1.1 our role and our approach to making final decisions;

X1.2 the key final decisions for the DPP4;

X1.3 the key changes we have made from our draft decision in May 2024;

X1.4 the anticipated outcomes for consumers and EDBs; and

X1.5 the challenges the final decisions address.

Our role and approach to making final decisions

X2 Our role is to provide EDBs with incentives to undertake activities that benefit consumers over the long-term, given the position of EDBs as natural monopolies. More specifically, our regulation (including our decision making in the DPP4 reset) aims to promote the long-term benefit of consumers by promoting outcomes that are consistent with outcomes produced in competitive markets, such that EDBs:[2]

X2.1 have incentives to innovate and to invest, including in replacement, upgraded, and new assets;

X2.2 have incentives to improve efficiency and provide services at a quality that reflects consumer demands;

X2.3 share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and

X2.4 are limited in their ability to extract excessive profits.

[1] **Chapter 1** lists the 16 'non-exempt' EDBs that are required to comply with price-quality regulation. The remaining EDBs are 'exempt', by virtue of meeting statutory 'consumer ownership' criteria and are subject to information disclosure regulation only.

[2] Commerce Act 1986, s 52A(1).

X3 A key tool in achieving this is price-quality regulation. Price-quality regulation limits the maximum revenues non-exempt EDBs can recover for electricity lines services they supply to consumers, while imposing minimum standards for the service quality consumers receive in return.

X4 The current default price-quality path is due to expire on 31 March 2025, and the final decisions in this paper set out the new path that will replace it from 1 April 2025.[3]

X5 When we last set revenue allowances for EDBs in 2019, inflation and interest rates were low and the decarbonisation/electrification imperative had not yet translated to substantial network investment needs. By contrast, EDBs have experienced inflationary cost pressures over recent years, and forecast significantly higher investment in asset renewal and replacement, as well as to support the energy transition.

X6 This document outlines our final decisions for the DPP reset. The DPP is part of a wider price-quality toolkit that works together to achieve the s 52A purpose of Part 4 of the Commerce Act 1986 (the Act). The toolkit also includes in-period adjustments, such as reopeners and Large Connection Contracts (LCC). Those, along with customised price-quality paths (CPPs), enable EDBs to respond to changes in their specific circumstances and better manage uncertainty. See **Chapter 1** for more about the price-quality toolkit.

[3] All references to years in this paper (unless otherwise stated) are to regulatory years ending 31 March. For example, 2026 is a reference to the year commencing 1 April 2025 and ending 31 March 2026.

Summary of final DPP4 price-quality path decisions[4]

- DPP4 covers the five-year period from 1 April 2025 to 31 March 2030.

Total revenues (see Chapter 4)

- Total forecast net allowable revenue allowances is $11.5 billion in nominal terms. This is an increase of 47% in real terms compared to the five-year DPP3 regulatory period.
- To mitigate price shocks to consumers we have limited the initial real increase in distribution revenue per ICP to 20% in most cases.[5] This equates to approximately $10 per month (ex GST) on average for a household consumer electricity bill.[6]
- Revenue increases over the remainder of the period differ for each EDB to ensure revenues cover forecast costs within the regulatory period.

Expenditure allowances (see Chapter 2)

- Total ex-ante expenditure allowances for capital expenditure (capex) and operating expenditure (opex) combined are $10.4 billion (nominal, net of capital contributions) for DPP4. The allowance is $1.4 billion (nominal) or 12% less than EDBs' 2024 asset management plan forecasts of $11.9 billion. The total expenditure allowance is 30% higher than the DPP3 allowance in real terms.
- EDBs have the opportunity to apply for an increase to their expenditure allowances during the period through flexibility mechanisms, including reopeners and CPPs. These changes are subject to a separate approval process.

Capex (see Chapter 2)

- The capex allowance is $6.4 billion (nominal, net of capital contributions) for DPP4. The allowance is $1.2 billion (nominal) or 17% less than EDBs' 2024 asset management plan forecast of $7.6 billion for the DPP4 period.
- The capex allowance is 37% higher than the DPP3 allowance in real terms.

Opex (see Chapter 2)

- The opex allowance is $4.1 billion (nominal). The allowance is $0.2 billion or 4% less than EDBs' 2024 asset management plan forecast of $4.2 billion for the DPP4 period.
- This is 22% higher than the DPP3 allowance in real terms.
- The final opex allowance includes provision for six step-changes in relation to: insurance, low voltage monitoring, cybersecurity, consumer engagement, software-as-a-service, and a graduate programme.

Incentives (see Chapter 3)

- The Incremental Rolling Incentive Scheme (IRIS) incentives rates for capex and opex are equal (32%). This ensures the regime continues to incentivise EDBs to choose the most efficient solution, regardless of expenditure category.

Innovation and non-traditional solutions allowance (see Chapter 3)

- An innovation and non-traditional solutions allowance (INTSA) is available upon application. It is capped at 0.8% of allowed revenue for each EDB over the DPP4 period. We have ringfenced a quarter of this allowance, or 0.2% of allowed revenue, for projects that involve an EDB collaborating with another EDB. INTSA targets innovation that would otherwise not occur.

Quality standards and incentives (see Chapter 3)

- The SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) approach from DPP3 has been retained, with no new measures added. There are minor refinements to how we set and apply the quality standards and incentives for DPP4.[7]

X7 The final DPP4 decisions are described in the box and below sections. See **Chapters 2 - 4** for the rationale, and **Attachments B – H** for background analysis for each final decision. **Attachment A** provides a full list of the final decisions for DPP4.

Key final decisions for DPP4

Revenue path

X8 Each EDB's revenue path has two parts:

X8.1 forecast net allowable revenue, that allows for recovery of the EDB’s forecast costs – this is what we determine in the DPP; and

X8.2 forecast allowable revenue, that also includes recovery of pass-through costs (eg, transmission charges) and recoverable costs (eg, revenue wash-up amounts and incentive scheme carry-forward amounts). These components are calculated following the rules and definitions set out in EDB Input Methodologies (IMs).

Starting prices

X9 The net allowable revenue path allows EDBs the opportunity to recover the forecast costs of investing in and running their networks – also known as 'building blocks' revenue. Between resets, these costs may change due to factors like inflation, changes in demand, or changes to the cost of capital.

X10 The costs EDBs face, including both their operating costs and their cost of capital, have increased over the DPP3 period. We forecast an average 57% increase in building blocks costs for DPP4 compared to DPP3. The specific drivers of these increases are illustrated in Figure X1.

[4] Some figures quoted in this summary do not sum up, due to rounding.

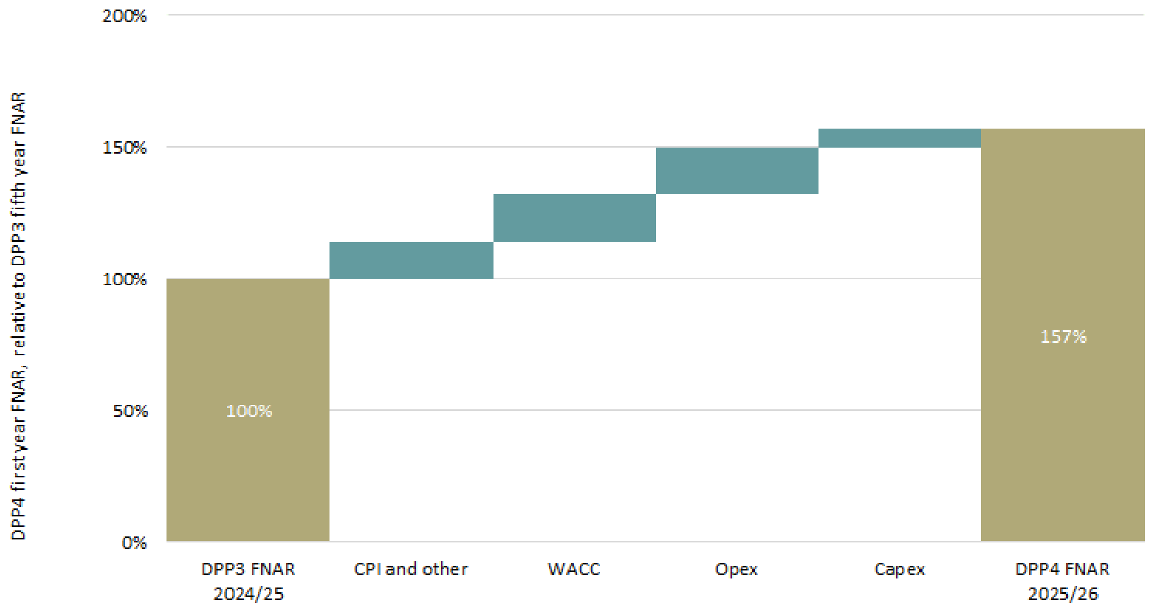
[5] We use the term 'distribution revenue' to refer to forecast net allowable revenues plus recoverable costs. This is because certain recoverable costs – IRIS incentives and wash-up drawdowns – have a material effect on the revenues EDBs can recover and a flow on effect on consumer prices and EDB financeability. As we have assessed 'price-shocks' on real per ICP basis, the initial nominal total increase differs between EDBs.

[6] The household consumer bill estimates have been rounded to the nearest $5.

[7] SAIDI refers to the average total duration of interrupted power supply in a year per customer in minutes. SAIFI refers to the average number of interruptions to power supply per customer in a year. Both SAIDI and SAIFI exclude interruptions originating on the low voltage portion of the network.

X11 To meet these costs over the regulatory period, we have increased revenue allowances in two steps, with an initial increase followed by smaller year-on-year increases over the remainder of the period. The 2026 forecast net allowable revenues (**decision P1**) that result from this are set out in Table X1 below.

Figure X1 Components of change in forecast net allowable revenues (FNAR) between the last year of DPP3 and first year of DPP4 (in nominal terms, unsmoothed).[8]



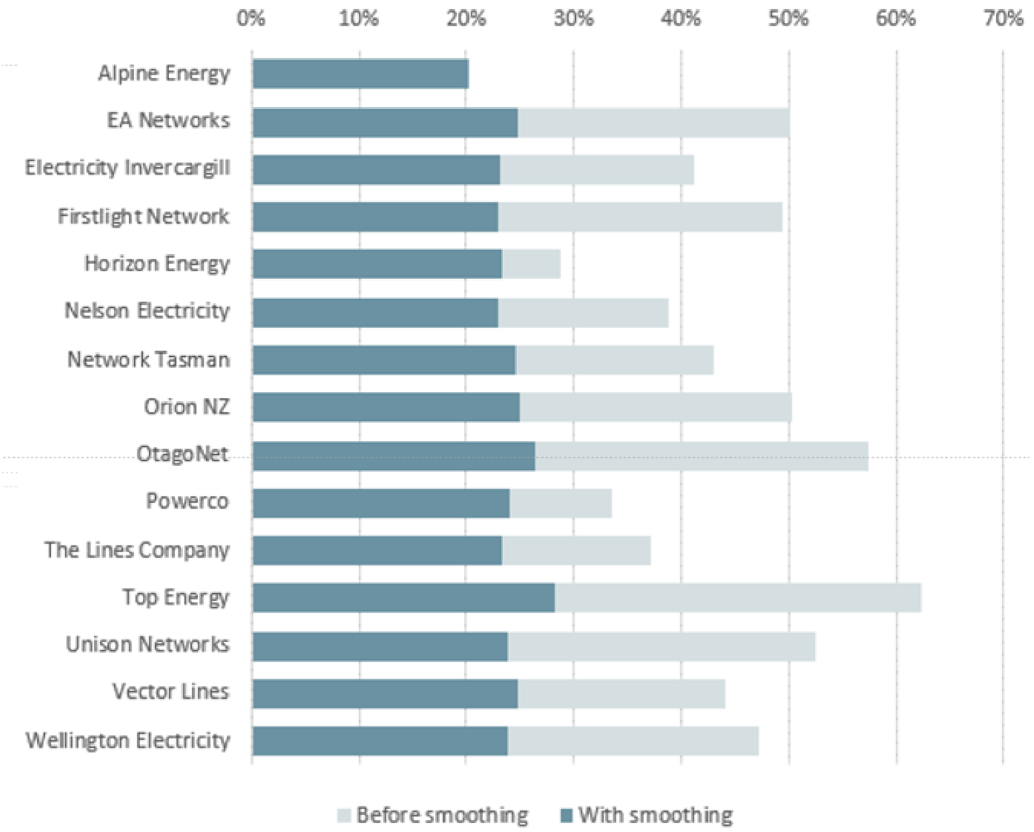
X12 To accommodate the inflation and WACC components shown in Figure X1, and to enable EDBs to invest to provide services at a quality that reflects consumers demands, our final decision is to allow EDB 'distribution revenues'[9] to increase by 24% on average in nominal terms between 2025 (the last year of DPP3) and 2026 (the first year of DPP4).

[8] The item 'DPP3 CPI and other change' includes changes in opening RAB and other financial model initial conditions over the course of DPP3 (largely driven by higher than forecast inflation), forecasts of CPI over DPP4, forecasts of disposed assets, forecast depreciation on existing assets, and tax allowance changes. WACC refers to the weighted average cost of capital. Figure excludes Aurora and Powerco.

[9] We use the term 'distribution revenue' to refer to forecast net allowable revenues plus recoverable costs. This is because certain recoverable costs – IRIS incentives and wash-up drawdowns – will have a material effect on the revenues EDBs can recover and a flow on effect on consumer prices and EDB financeability.

X13 The specific changes in distribution revenue for each EDB are shown in the darker bars in Figure X2.

Figure X2 Nominal change in smoothed distribution revenue from 2025 to 2026 [10]



Mitigating price-shocks to consumers

X14 The Act provides us some tools to smooth the changes in revenue both between regulatory periods and year-to-year. These tools are present value neutral, although we recognise that deferring too much revenue may cause financial hardship for suppliers. To mitigate price-shocks to consumers, we aimed to limit the initial increase in real per-consumer (ICP) revenue to 20% (**decision P3**).[11]

[10] Aurora Energy is not included in this figure as they are on a Customised Price-quality Path until 2026. For Alpine, the smoothed and unsmoothed values are the same.

[11] The average nominal increase of 24% reflects the 20% real per consumer limit (with one exception) combined with forecast CPI inflation of 2.3% between 2025 and 2026, and EDB-specific customer growth of on average 1.1%.

X15 To further mitigate price-shocks over the regulatory period we have also:

X15.1 limited annual average forecast increases in distribution revenue to 10% (again on a real per ICP basis);

X15.2 set a revenue smoothing limit (**decisions R2.1 and R2.2**) that limits the extent to which recoverable costs (principally the wash-up drawdown) can increase allowable revenues to 10% (over and above the CPI-X rate of change); and

X15.3 set an undercharging limit (**decision R1.3**) that allows EDBs to defer up to 10% of their forecast allowable revenue each year via the wash-up account. This enables revenue smoothing beyond what we have required where EDBs consider that doing so would benefit their customers and their financial position allows it.

Table X1 Starting prices (nominal $ million) and alternate X-factors[12]

EDB	Starting prices - FNAR in 2026 (nominal $ million)	X-factor - rate of change relative to CPI[13]
Alpine Energy	73.36	0.0%
EA Networks	44.28	(10.7%)
Electricity Invercargill	16.95	(7.7%)
Firstlight Network	34.27	(10.2%)
Horizon Energy	34.13	(2.4%)
Nelson Electricity	7.22	(7.1%)
Network Tasman	37.18	(8.3%)
Orion NZ	231.40	(9.8%)
OtagoNet	34.65	(12.3%)
Powerco	446.16	(3.9%)
The Lines Company	48.65	(6.0%)
Top Energy	51.69	(13.5%)
Unison Networks	133.36	(11.8%)
Vector Lines	579.39	(8.0%)
Wellington Electricity	118.70	(9.6%)

Managing EDB financeability

X16 Some EDBs told us they had concerns about their ability to finance necessary investments in the DPP4 period if significant amounts of revenue were to be deferred. This issue has been termed 'financeability'. To mitigate risks to EDB financeability, enabling them to invest in meeting consumers' needs, our final decision is to:

X16.1 allow EDBs the prospect of fully recovering building blocks revenue plus accrued wash-up balance over DPP4, with no forecast deferral into future periods (**decision P1**); and

[12] Aurora Energy is not included in this table as they are on a CPP until 2026.

[13] Section 53P(5) of the Act and the EDB DPP4 determination expresses X-Factors in 'CPI minus X' terms. The X-factor values presented here are negative (by accounting convention, in brackets). As such, they will allow forecast net allowable revenue to increase at these rates above inflation.

X16.2 set EDB-specific alternative rates of change (**decision P3**) to enable this, as set out in Table X1.

X17 As a sense-check of our final revenue decisions for their effect on EDBs' financeability, we have applied a notional assessment using Standard & Poor's FFO/Debt and Debt/EBITDA ratios as indicators (**decision P5**).[14]

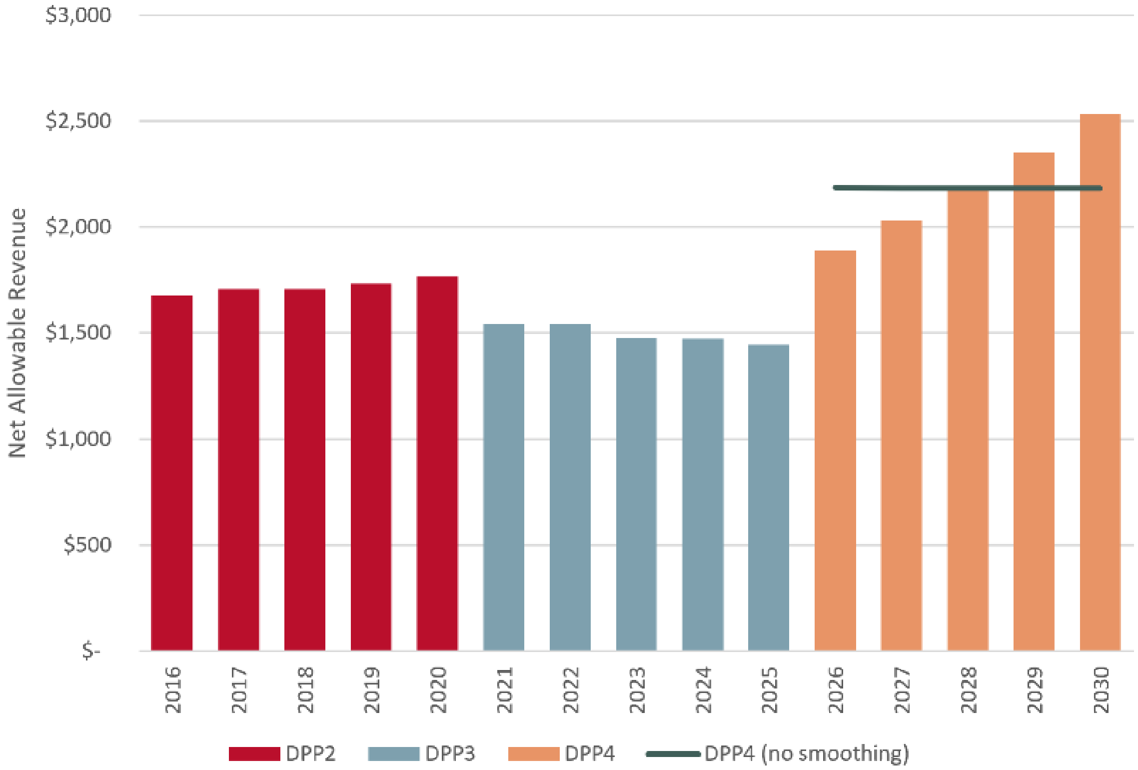
Long term change in revenue

X18 To put the revenue change between DPP3 and DPP4 in context, Figure X3 illustrates the change in net allowable revenue over DPP2, DPP3 and DPP4. As Figure X3 shows, consumers have benefited from reduced (and declining in real terms) revenues over DPP3. This reverses in DPP4, for the reasons described above.

X19 The impact of our final decisions on smoothing is shown in Figure X3 by the difference between the DPP4 final revenue (orange bars) and the unsmoothed DPP4 revenue (green line).

[14] Funds From Operation over notional Debt, and notional Debt over Earnings Before Interest Tax Depreciation and Amortisation. See **Chapter 4** and **Attachment G**.

Figure X3 Long-term revenue paths – all DPP EDBs, excluding Aurora (real 2026 $ million)[15]



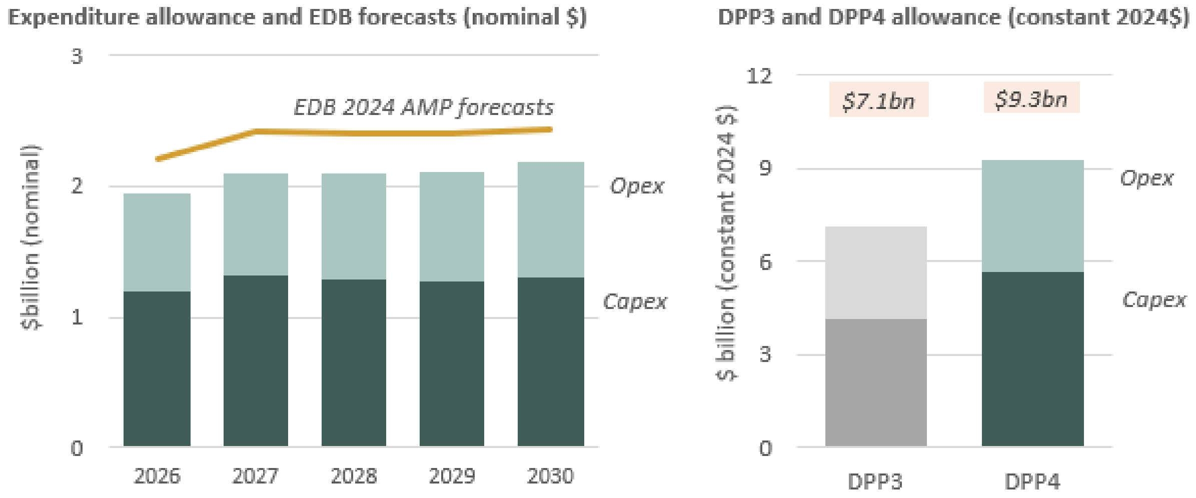
Total expenditure allowances

X20 Our final decision is to allow a DPP4 total expenditure ex-ante allowance of $10.4 billion for opex and capex combined (nominal, net of capital contributions). Our final decision assumes that high rates of increase in input costs faced by EDBs over the past few years will continue to persist to some extent. In nominal terms net of capital contributions, the DPP4 final allowance is $1.4 billion or 12% less than EDBs' 2024 asset management plan forecasts of $11.9 billion. The left side of Figure X4 below shows this difference across each year of DPP4.

X21 The right side of Figure X4 shows that, comparing between regulatory periods in 2024 constant dollars, the expenditure allowance for DPP4 of $9.3 billion is $2.2 billion or 30% higher than the DPP3 allowance of $7.1 billion.

[15] On the use of real 2026 dollars here, see section *Explanation of how we have used numbers in this document* in **Chapter 1** paragraph 1.19.

Figure X4 DPP3 and DPP4 expenditure allowances and 2024 AMP forecasts.[16]



X22 Table X2 shows the DPP4 total expenditure allowance for each EDB, a breakdown of the allowance into constant 2024 dollars and the allowance we have made for input price inflation. For comparison, we have also shown DPP3 period allowances.

[16] AMP refers to each EDB's asset management plan.

Table X2 DPP3 and DPP4 expenditure allowances with input cost adjustment[17]

EDB	DPP3 period allowance (constant 2024 $ million)	DPP4 expenditure allowance (constant 2024 $ million)	DPP4 allowance for input price inflation (nominal $ million)	DPP4 expenditure allowance (nominal $ million)
Alpine Energy	193.2	302.3	36.7	339.0
Aurora Energy[18]	628.4	689.7	87.6	777.2
EA Networks	157.6	154.3	18.7	173.0
Electricity Invercargill	56.6	71.8	8.9	80.7
Firstlight Network	111.1	158.4	19.2	177.6
Horizon Energy	98.6	124.1	15.1	139.2
Nelson Electricity	21.6	24.4	3.0	27.4
Network Tasman	117.0	171.5	20.4	191.9
Orion NZ	780.2	1,089.2	135.4	1,224.6
OtagoNet	138.9	201.7	25.6	227.2
Powerco	1,725.5	2,236.2	279.4	2,515.6
The Lines Company	172.5	212.6	25.7	238.3
Top Energy	174.8	235.4	28.7	264.2
Unison Networks	497.1	705.3	88.2	793.5
Vector Lines	1,844.3	2,323.2	278.1	2,601.3
Wellington Electricity	408.0	594.9	73.4	668.3
Total	**7,125.5**	**9,294.8**	**1,144.2**	**10,439.0**

X23 Consistent with DPP3, the DPP4 final decision provides separate allowances for capex and opex for the purposes of determining maximum allowable revenues. However, ultimately EDBs have discretion over how their revenue is spent (whether that is capex or opex) and our incentive mechanisms are designed to allow opex and capex substitutions where efficient without financial bias towards one or the other.

[17] DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora Energy, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

[18] The values included for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from its CPP to the DPP, with its CPP ending 31 March 2026.

Capex

X24 **Decision C2** is that the DPP4 capex allowance (net of capital contributions, in constant dollars) provides for either an EDB's total forecast net capex or an increase of 25% relative to the 2020 to 2024 historical reference period net capex, whichever is lower, with a subsequent adjustment for changes in forecasted levels of capital contributions for capped EDBs. We consider this approach is appropriate given the context for DPP4, of large uplifts with ranging need, an evolving environment, expenditure drivers that are subject to significant uncertainty, and deliverability challenges facing the sector.

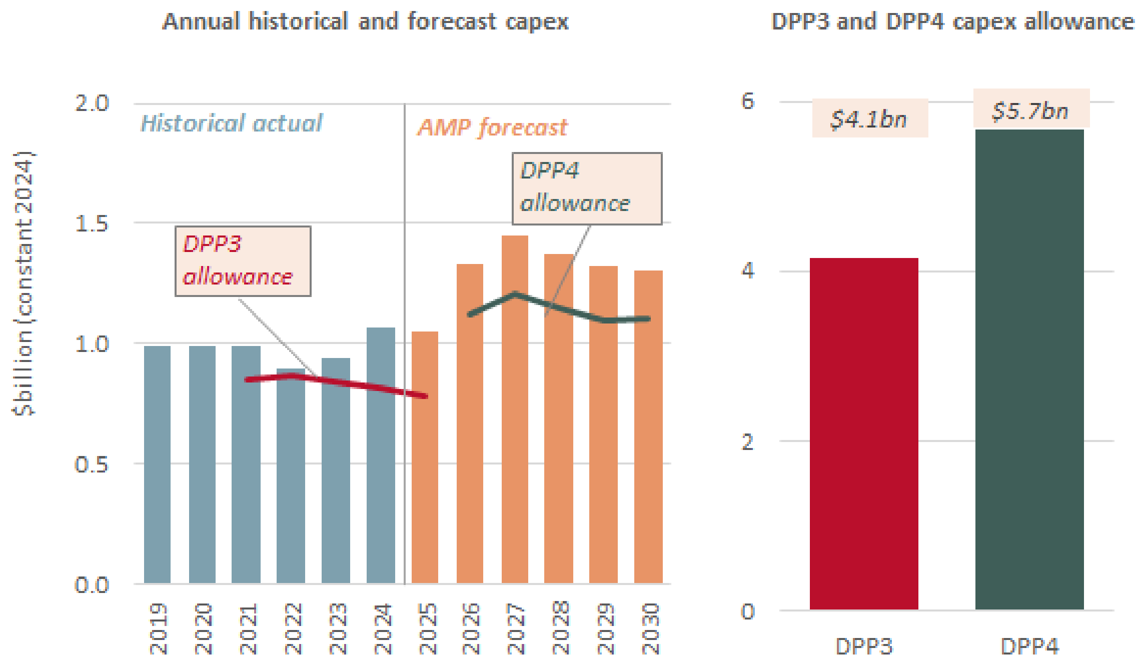
X25 **Decisions C3** and **C6** provide allowances for the additional input cost of investments by escalating the historical reference period and forecast capex by the All-Groups CGPI, with adjustments to reflect historical and expected input cost growth above All-Groups CGPI. See *Total capex allowance components* section in **Chapter 2** for further information.

X26 The outcome of these decisions is a DPP4 capex allowance of $6.4 billion (nominal, net of capital contributions). On the same basis (nominal, net of capital contributions) this allowance is $1.2 billion or 17% less than EDBs' 2024 asset management plan forecast of $7.6 billion for the DPP4 period and $0.1 billion or 1.0% higher than the draft capex allowance.

X27 Figure X5 shows the capex profiles across DPP3 and DPP4 regulatory periods. In 2024 constant dollars, the total DPP4 capex allowance of $5.7 billion is $1.5 billion or 37% higher than the DPP3 capex allowance of $4.1 billion.[19]

[19] These figures do not sum up due to rounding.

Figure X5 Capex profile and DPP3 and DPP4 allowances comparison (constant 2024$)[20]



X28 Our final decisions on capex reflect:

X28.1 A higher allowance for DPP4 is appropriate as it recognises that EDBs are facing cost increases, and that greater investment is required to maintain reliability and meet consumer demand. For example, assets increasingly need replacing on networks largely built last century. In addition, there is an increased drive for electrification particularly in transport and process heat.

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[20] DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

X28.2 EDBs' AMP forecasts are prepared using a variety of assumptions and approaches. There is significant uncertainty about the timing, scale, and location of forecast demand increases and risks to network resilience are evolving. The primary purpose of the AMP is as an asset management tool. AMPs are not necessarily an appropriate forecast for investment for revenue setting purposes. Nonetheless they represent the most comprehensive information available for understanding likely capex needs. While capex allowances are based on AMP forecasts, we do not consider it appropriate to set allowances based on full acceptance of EDBs' forecasts. Therefore, while our final decision on capex allowances enables EDBs to spend more in DPP4, it is less than the total forecast by EDBs over the DPP4 period.

X28.3 There are in-period adjustment mechanisms for EDBs to apply for an increase to their allowances or CPPs during the regulatory period where appropriate. We consider our assessment is consistent with the relatively low-cost purpose of DPP regulation under s 53K of the Act, the information available to us, and the need for consumers to have confidence that step changes in investment are assessed via the appropriate regulatory tool.

X29 See **Chapter 2** and **Attachment B** for detail about the final decisions and our approach for setting capex allowances.

Opex

X30 **Decision O1.1** reflects our view that a base, step, and trend approach remains appropriate to set forecast opex allowances over the DPP4 regulatory period. This approach takes current levels of cost and productivity and projects them into the future, with additional allowances for specific approved step changes. This approach meets the need for EDBs to fund ongoing and new activities while also providing incentives for EDBs to improve efficiency over time.

X31 Within the base, step, and trend approach, our final decisions make a number of changes from DPP3 to better reflect the likely opex needs and cost inflation pressures affecting EDBs over the DPP4 period. These changes include:

X31.1 **amending our approach to assessing step changes** to help ensure prudently incurred costs are not unreasonably excluded and to better reflect the current context (**decisions O2.1-O2.6**).

X31.2 **accepting some of the step-changes** EDBs **applied for**: insurance, low voltage (LV) monitoring and data, consumer engagement, cybersecurity, greater use of software-as-a-service (SaaS), and a graduate programme (**decisions O3.1-O3.5, O3.14**). Other step changes requested did not sufficiently satisfy our step change decision-making framework, and we have declined them for DPP4.

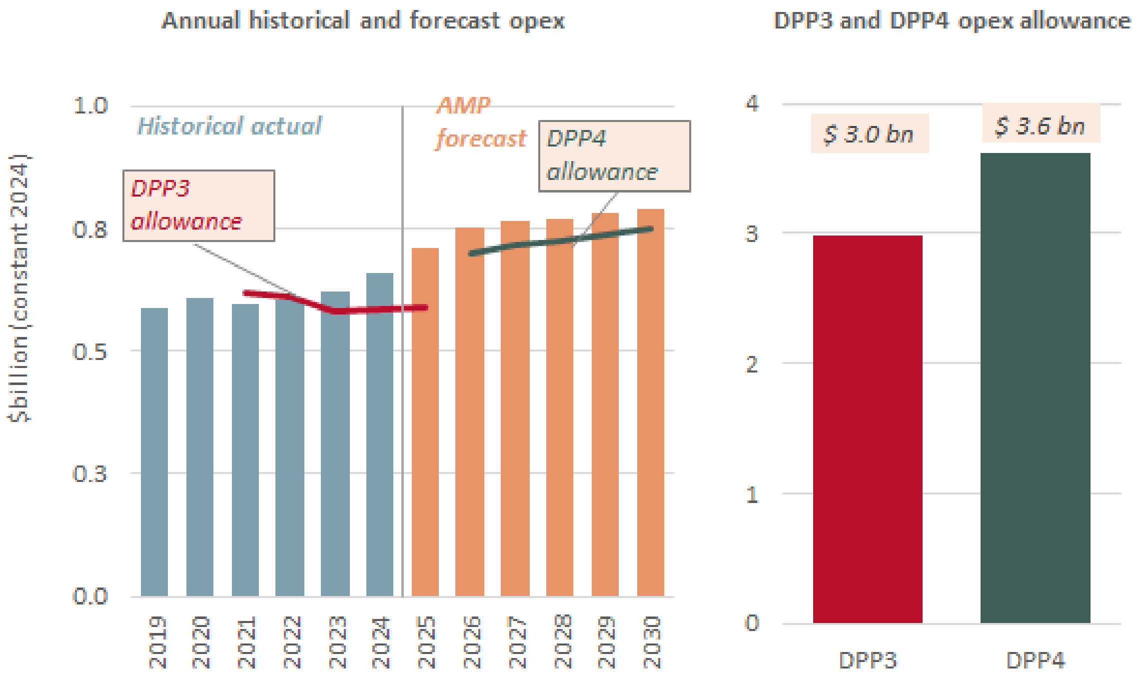
X31.3 **updating the trends** to include industry-specific inflation increases in our cost escalators, include capex growth as a driver of non-network opex, and better account for ICP growth to scale up opex requirements across DPP4 (**decisions O4.1 – O6.1**).

X32 We have capped the aggregate value of step changes for each EDB at 5% of their opex excluding step changes (**decision O3.7**). This reflects the relatively limited scrutiny we have given to the size of each step change. This cap does not include specified values calculated for insurance increases and access to low-voltage data, reflecting costs that we have independent evidence to support.

X33 Figure X6 shows the opex profiles across DPP3 and DPP4 regulatory periods. In 2024 constant dollars, the total DPP4 opex allowance of $3.6 billion is $0.6 billion or 22% higher than the DPP3 opex allowance of $3.0 billion.

X34 See **Chapter 2** and **Attachment C** for detail about the final decisions and our approach for setting opex allowances.

Figure X6 Opex profile and DPP3 and DPP4 allowances comparison (constant 2024$)



Incentives

X35 Our price-quality regime provides incentives for efficient investment by EDBs. While we determine opex and capex allowances separately given their different drivers, EDBs have the flexibility under our regime to substitute between opex and capex responses where it is efficient to do so. In addition, EDBs have the flexibility to overspend or underspend their total allowances, subject to the Incremental Rolling Incentive Scheme (IRIS). These features are central to the regime, and of increasing importance in DPP4 given the uncertainty in elements of EDBs' forecasts and the opportunities offered by emerging technologies.

X36 **Decision I1** is to maintain equivalent IRIS incentive rates between capex and opex, to promote financial neutrality for spending decisions. With opportunities to substitute between traditional and non-traditional solutions expected to rise, we consider that financial neutrality between expenditure categories (opex vs capex) is important to provide suppliers with incentives to innovate and implement the most efficient solution. See **Chapter 3** and **Attachment D**.

Innovation

X37 **Decision U1** is to introduce an Innovation and Non-traditional Solutions Allowance (INTSA), capped at 0.8% of DPP4 allowed revenue, including 0.2% of revenue which is ring-fenced for collaborative projects.

X38 EDBs have the flexibility to prioritise spending their opex and capex allowances, including on innovative projects and non-traditional solutions. The INTSA is an additional incentive to encourage EDBs to try out new solutions that benefit their consumers, either on their own or working together.

X39 We expect that technologies, such as the use of batteries and managed electric vehicle charging, are likely to become increasingly prevalent in Aotearoa New Zealand over the DPP4 period changing the way electricity networks are used and potentially how they are operated. Our intention for the INTSA is to provide EDBs with an additional incentive to trial new solutions through the DPP4 period to find alternative ways to adapt their networks to decarbonisation trends, resilience expectations and changing consumer preferences.

X40 Consumers benefit when distribution costs are lower, because one or more EDBs have found alternative approaches that enable the deferral or avoidance of major capex or efficiencies.

X41 On application, EDBs will be able to recover additional revenue up to 0.8% of their allowed revenue on one or more eligible projects over the DPP4 period, with a quarter of this, or 0.2% of allowed revenue, ring-fenced for projects that involve working together with one or more other EDBs. See **Chapter 3** for INTSA eligibility criteria and **Attachment D** for the allowance figures per EDB.

Quality Standards and Incentives

X42 Quality standards are an important part of a price-quality path and are intended to ensure that any cost savings sought by EDBs do not come at the expense of quality of service. We have fundamentally retained our approach from DPP3 to setting network quality standards and incentives based on network reliability, represented by the frequency and duration of network outages.

X43 Table X3 presents the final decisions for quality standards.

Table X3 Quality standards for DPP4

EDB	Unplanned SAIDI (1-year)	Unplanned SAIFI (1-year)	Planned SAIDI (5-year)	Planned SAIFI (5-year)	Extreme outage (per event)[21] [22]
Alpine Energy	118.47	1.1372	825.77	3.1437	120 SAIDI
Aurora Energy[23]	128.36	1.9675	1,077.78	6.0924	6m CIM
EA Networks	87.38	1.2416	1,238.47	4.4045	120 SAIDI
Electricity Invercargill	27.15	0.6608	125.94	0.5702	120 SAIDI
Firstlight Network	230.43	3.3101	1,213.15	6.7271	120 SAIDI
Horizon Energy	184.80	2.2709	944.50	5.9856	120 SAIDI
Nelson Electricity	18.62	0.4063	162.10	2.1297	120 SAIDI
Network Tasman	98.33	1.1358	1,067.94	4.4119	120 SAIDI
Orion NZ	80.47	0.9819	218.24	0.7399	6m CIM
OtagoNet	168.37	2.3401	2,323.77	9.2088	120 SAIDI
Powerco	189.27	2.1550	849.75	3.8125	6m CIM
The Lines Company	190.55	3.2839	1,284.15	7.8774	120 SAIDI
Top Energy	399.25	4.8196	1,727.59	8.5279	120 SAIDI
Unison Networks	81.52	1.7244	688.37	4.9114	6m CIM
Vector Lines	110.07	1.4034	643.92	3.1661	6m CIM
Wellington Electricity	37.82	0.5829	76.66	0.6089	6m CIM

X44 The starting point for our approach to quality is that there should be no material deterioration in reliability, as assessed using the quality standards. The quality incentive scheme (QIS) encourages EDBs to make appropriate trade-offs about the level of quality they deliver, and the cost incurred in doing so.

[21] The extreme event standard is specified in SAIDI minutes or CIM terms. CIM means customer interruption minutes, which is the sum of the total duration in minutes accumulated for each ICP for each interruption, with 'm' representing millions.

[22] Extreme outage values are indicative only. We have determined these values based on the EDB's number of ICPs at 31 March 2024. However, the extreme event provision operates on whether either threshold is exceeded during the period so may change if the EDB's number of ICPs change.

[23] Aurora is currently on a CPP which ends on 31 March 2026. Under clauses 9.5 and 9.6 of the DPP determination, where an EDB transitions from a CPP to a DPP during the regulatory period, the planned SAIDI and SAIFI limits are adjusted in the assessment of compliance. For Aurora, this means that for assessment purposes, it will divide the planned SAIDI and SAIFI limits by five years (regulatory period), then multiply by four years (assessment periods on the DPP) to calculate the value of the planned SAIDI and SAIFI limits that apply.

X45 Our view is that the current quality standards and QIS are fit for purpose (**decisions QS1 – QS11, and QIS1 – QIS10)** and encourage EDBs to invest in network capability and resilience. The final decision is to retain the quality standards based on network reliability, measured by SAIDI and SAIFI, as the most important dimension of quality to consumers.[24]

X46 Our final decision is to make minor adjustments to the QIS for EDBs to maintain or improve the quality of service they deliver. **Decision RP7** reflects that outages directly associated with an INTSA project would be able to be excluded from assessment against the quality standards and incentives up to a specified limit of 1% of the standard limits. See **Chapter 3** and **Attachment E**.

Key changes from the draft decision

X47 We received 42 submissions and 12 cross submissions on the DPP4 draft decision.[25] We also received six submissions following our Innovation workshop held on 14 August 2024.[26]

X48 There was a high amount of detailed and constructive feedback provided, which has been considered in making our final decisions. Overall, the submissions received were largely supportive of draft decisions. Where we received strong support for our draft decisions, we have generally either made no changes or only minor edits to our final decisions.

Key changes

X49 We have made a few key changes from our draft decisions. These are:

X49.1 Opex step changes: We have approved further step changes for EDBs, including one new step change category (graduate programme). We have also amended how we apply the 5% aggregate cap on opex step change increases to exclude specified amounts for some step changes (insurance and LV data costs).

[24] SAIDI refers to the average total duration of interrupted power supply in a year per customer in minutes. SAIFI refers to the average number of interruptions to power supply per customer in a year. Both SAIDI and SAIFI exclude interruptions originating on the low voltage, portion of the network.

[25] We have published all non-confidential submissions and cross-submissions on our draft decision through our 2025 reset of the electricity default-price-quality path webpage.

[26] Also published through the above webpage.

X49.2 Innovation: We have increased the INTSA cap to 0.8% of allowed revenue for each EDB over the DPP4 period, where 25% of this amount (0.2% of allowed revenue) is available only when the EDB is working together with one or more other EDBs.

X49.3 WACC: We have used an updated WACC of 7.10%. This is lower than the value of 7.37% used in our draft decision, primarily due to a reduction in the risk-free rate.

X50 We have also made some minor changes to our final decisions and incorporated updated information.

X50.1 Capex and opex: We have used updated information. This has resulted in changes to individual EDB allowances, with the total capex and opex allowances provided increasing slightly.

X50.2 Quality: We have made changes to our quality decisions, shortening the reference period for planned interruptions and matching de-weighting of interruptions between the quality standards and incentive scheme.

X50.3 Revenue path: We have used updated input information and fixed data errors which have changed the alternate X-factors used.

Revenue and expenditure allowance changes

X51 As a result of these changes, the forecast net allowable revenue and expenditure allowances have changed compared to the draft decision:

X51.1 The final decision for forecast net allowable revenue allowances is $0.2 billion (nominal) less than the draft decision.

X51.2 Our final decision for capex allowances is a $66 million (nominal) increase from the draft decision.

X51.3 Our final decision for opex allowances is a $144 million (nominal) increase from the draft decision.

Updated household consumer bill impact modelling

X52 The DPP4 Final decision, combined with transmission costs from the recently released Transpower RCP4 Final decision,[27] is estimated to result in an average increase to monthly household electricity bills of $10 nationally.[28] This is $5 less than the estimated impact from the DPP4 Draft decision. The difference from the draft decision is principally due to the lower WACC and updating data to use more recent information (including EDB financial information and consumer bill data).

X53 The estimated increase in the average monthly household electricity bill varies between regions from $10 to $25. This means that while many households will have a lower increase than expected in the draft decision, for some the increase is greater (the range was $10 to $20 in the draft). The different changes at an individual EDB level are largely due to the impact of opex decisions, particularly new step changes, and the use of updated revenue forecasts for 2024/2025 from EDBs.

Anticipated outcomes for consumers and EDBs

X54 Our regulation under Part 4 of the Commerce Act is a package designed to promote the long-term benefit of consumers by promoting outcomes consistent with those produced in workably competitive markets, specified in the s 52A purpose of Part 4. We outline below the anticipated outcomes for consumers and EDBs drawing on the regime design, our recent IM decisions published in December 2023, and the final decisions for DPP4 set out in this paper**.** These anticipated outcomes reflect the outcomes specified in the s 52A purpose of Part 4.

Anticipated outcomes for consumers

X55 Consumers will benefit from:

X55.1 An appropriate level of investment in the networks they rely on to maintain reliability of service, enhance network resilience, and to support greater demand as part of the shift towards decarbonisation.

[27] Commerce Commission "Transpower's individual price-quality path for the regulatory control period commencing 1 April 2025 - Decision and reasons paper" (29 August 2024).

[28] The consumer bill impact modelling has all been rounded to the nearest $5.

X55.2 Some forecast expenditure being excluded from DPP4 due to uncertainty and deliverability risks. This provides confidence that what consumers pay for electricity distribution services represents value for money and does not contribute to excessive profits.

X55.3 Paying less over the long-term due to incentives on EDBs to improve their productivity and efficiency.

X55.4 A smoother and more gradual revenue recovery profile over DPP4 for EDBs that aims to mitigate the impact of price shocks.

Anticipated outcomes for EDBs

X56 Through our application of default price-quality regulation, we expect EDBs will:

X56.1 Invest more in DPP4 compared to previous regulatory periods, while also retaining the flexibility under the regime design to prioritise their spending as they see fit within their overall revenue allowance.

X56.2 Respond to greater incentives to improve their productivity and efficiency.

X56.3 Manage specific cost pressures in DPP4 through an updated cost of capital, recent levels of inflation being taken account of, and growth in other business costs such as cybersecurity being recognised.

X56.4 Explore innovative and non-traditional solutions with greater confidence through our 2023 IM Review and DPP4 decisions providing a new mechanism with a wider scope than was available under DPP3.

X56.5 Better understand their network by purchasing low voltage monitoring data in DPP4. This data is important as it will enable better asset understanding and management decisions on network capacity and consumer safety.

X56.6 Have more flexibility to seek additional revenues via reopeners, where appropriate. They also retain the ability to apply for a CPP, if that better suits their consumers' needs.

The challenges the final decisions aim to address

X57 What EDBs do in the next regulatory period will have significant implications for the longer-term capability, capacity, and resilience of their networks.

X58 In the DPP4 Issues paper we identified three challenges inherent in setting DPP4. The challenges were drawn from the context we described at that time.[29] Our view is that recent changes to the operating environment reinforce those challenges.

X59 The challenges related to how we could apply the DPP regulatory tools, alongside other price-quality regulation tools and information disclosure regulation, to promote the long-term benefit of consumers. These challenges form the structure of our substantive chapters (**Chapters 2 – 4**). Each chapter explains how the final decisions address the challenges in a way that promotes the long-term benefit of consumers. The challenges were to:

X59.1 **Enable EDBs to spend and invest to meet forecast consumer demands** (see **Chapter 2**). This challenge relates primarily to uncertainty about the need, timing, cost, and deliverability of investments and new operating activities. We have set DPP4 in a relatively low-cost way that enables EDBs to meet consumers' needs efficiently and effectively, acknowledging that in-period adjustment mechanisms may be appropriate in instances of uncertainty or where EDBs require step changes in investment. This approach is suited to the uncertain pace of electrification, questions about where and when to make significant resilience investments to support future-proofing network systems and infrastructure, and the increasing role of innovative and non-traditional solutions.

X59.2 **Incentivise performance and improvement during the energy transition** (see **Chapter 3**). This challenge related to how we could tailor the incentives, provided for by the IMs,[30] within the DPP for EDBs to continuously improve efficiency and deliver the appropriate quality of electricity distribution services. EDBs need to adapt to meet the needs of the energy transition, manage uncertainty and provide benefit for consumers. To do so, EDBs need to innovate and implement non-traditional solutions, likely at a rate not seen in prior periods. The new 'Innovation and Non-Traditional Solutions Allowance' supports this.

[29] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), p. 23.

[30] Commerce Commission "Part 4 Input methodologies Review 2023 - Final decision. Report on the IM Review 2023" (13 December 2023).

X59.3 **Manage price shock risks and the ability for EDBs to finance investments** (see **Chapter 4**). We acknowledge that New Zealanders are facing rising costs of living on a range of fronts. At the same time, it is in consumers' long-term interest for EDBs to be compensated for efficient costs and have incentives to invest in their networks on which consumers depend. We have limited initial price shocks to consumers, followed by year on year increases to give EDBs the prospect of fully recovering allowed revenues within the DPP4 period. Our decisions on capping initial revenue were also informed by a notional financeability assessment, to check whether a prudent and efficient supplier would be able to finance investment based on the path we have set.

Chapter 1 Introduction

Purpose of this chapter

1.1 This chapter briefly outlines our role, how and why we apply price-quality regulation to non-exempt EDBs, and other relevant regulatory tools. It also includes an explanatory note about how we have applied numbers in this document, specifically when we have used constant or nominal numbers.

1.2 The following chapters then cover the final decisions which contribute to addressing the three challenges we have explained are relevant to the DPP4 reset (see *The challenges the final decisions aim to address* section in the **Executive Summary** above). The attachments provide more detail and reasons for the key specific aspects of our final decision.

How we regulate price and quality under Part 4 of the Commerce Act

1.3 Through regulating price and quality, the Commerce Commission promotes the long-term benefit of consumers of electricity distribution services, in line with the purpose of Part 4 of the Commerce Act (Act).[31] We ensure that, through price-quality regulation, non-exempt EDBs have incentives to innovate, invest, improve efficiency, and provide services at a quality that reflects consumer demands. We also aim to ensure the benefits of efficiency gains are shared with consumers, including through lower prices, and to limit the ability of EDBs to earn excessive profits.

Decision-making framework

1.4 Our decision making on the DPP4 reset applies our decision-making framework, which centres on promoting the purpose of Part 4 (s 52A of the Act). In doing so, our intention is to retain approaches from DPP3 where they remain fit for purpose. We have made changes to the DPP3 approaches where the changes will:

1.4.1 better promote the purpose of Part 4;[32]

1.4.2 better promote the purpose of default/customised price-quality path regulation under s 53K;[33]

[31] Commerce Act 1986, s 52A.

[32] Commerce Act 1896, s 52A.

[33] Commerce Act 1986, s 53K.

1.4.3 better promote incentives for suppliers of electricity lines services to invest in energy efficiency and demand-side management, and to reduce energy losses (or better avoid disincentives for the same);[34]and

1.4.4 reduce unnecessary complexity and compliance costs.

1.5 This decision-making framework, and the other principles we use when setting a DPP, are explained in full in the DPP4 Issues paper.[35]

Application of DPP4

1.6 The current default price-quality path (DPP3) for EDBs is due to expire on 31 March 2025.[36] The final decision for DPP4, as outlined in this paper, will determine the maximum revenues and the required quality standards for non-exempt EDBs over the next five years from 1 April 2025.[37]

1.7 Of the 29 EDBs, 13 are exempt from price-quality regulation because they meet the statutory definition of 'consumer-owned'.[38] The EDBs we regulate using price-quality regulation, both DPPs and customised price-quality paths (CPPs), are set out in Table 1.1.

Table 1.1 Non-exempt EDBs currently subject to price-quality regulation

EDBs subject to the default price-quality path (DPP)			
Alpine Energy	Horizon Energy	OtagoNet Joint Venture	Unison Networks
EA Networks	Nelson Electricity	Powerco	Vector
Electricity Invercargill	Network Tasman	The Lines Company	Wellington Electricity
Firstlight Network	Orion	Top Energy	
EDBs subject to a customised price-quality path (CPP)			
Aurora Energy (ends 31 March 2026, at which time they will join DPP4)			

[34] Commerce Act 1986, s 54Q.

[35] Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), see **Attachments A** and **B** from page 65.

[36] All references to years in this paper (unless otherwise stated) are to regulatory years ending 31 March. For example, '2026' is a reference to the year commencing 1 April 2025 and ending on 31 March 2026.

[37] More information about DPP4 can be found on our "Electricity lines default price-quality path" webpage.

[38] 'Consumer-owned' is defined in the Commerce Act 1986, s 54D.

Decisions relating to Aurora Energy

1.8 We have made specific decisions for Aurora Energy's quality standards as part of the DPP4 process (see Table 3.2). Capex and opex decisions are indicative only (see Tables 2.1 and 2.3) and are included in this document to give Aurora and other interested parties an early preview of how DPP4 settings may apply when Aurora returns to the DPP from 1 April 2026. We will engage directly with Aurora in preparation for their transition from CPP to DPP. See **Attachment H** for more detail about the transition of Aurora Energy to the DPP.

Other price-quality regulation tools

1.9 The DPP is a relatively flexible tool that allows EDBs to spend how they see fit within the revenue allowance irrespective of what was included in the expenditure forecasts used to set the DPP.[39] We recognise that a lot can change for EDBs and their consumers over a five-year period. Where changes occur, we expect that EDBs would firstly look to reprioritise expenditure to meet the needs of their consumers.

1.10 In some cases, however, an EDB on a DPP may forecast a need to incur additional expenditure that it may not be able to accommodate within the settings of its current price-quality path through reprioritisation and substitution of expenditure or identifying efficiencies.[40] This is why the price-quality regulation toolkit includes flexibility mechanisms, such as recoverable and pass-through costs, reopeners, large connection contracts, and Customised Price-quality Paths (CPPs).[41]

1.11 **Pass-through costs and recoverable costs** are costs that can be recovered from consumers above an EDB's net allowable revenue.[42] There are costs we allow EDBs to 'pass-through' to their consumers which are generally outside a supplier's control, eg, Transpower's transmission charges and local body rates. There are also specific costs (or reduced revenues) that can be recovered from (or provided to) consumers such as efficiency incentive payments under IRIS, quality incentive amounts, or wash-up amounts set by us. These amounts are collectively called pass-through costs and recoverable costs.

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[39] Commerce Act 1986, s 53K.

[40] The price-quality paths we set do not restrict the extent of a regulated supplier's spending. If a supplier chooses to spend more than the capex or opex allowances we use to set its price-quality path, the IRIS scheme shares a proportion of that overspend with consumers. The scheme is symmetrical, with consumers receiving the same proportion of any underspend. See **Chapter 3** for how we have updated the capex IRIS incentive rate (noting that the opex IRIS incentive rate is a function of the IMs).

[41] We use the term 'flexibility mechanisms' to refer to changes which can be applied during a DPP regulatory period which includes DPP-related in-period adjustment mechanisms and CPPs.

[42] For a detailed explanation for the different components of an EDB's revenue path and the terminology we use to describe it, see **Attachment F**.

1.12 **Reopeners** allow for EDBs to apply for changes to the revenues and quality path in specified circumstances during the regulatory period, for example, in response to unforeseen events. The scope and process for reopeners is set out in the Input Methodologies (IMs), and our recent 2023 IM Review decisions expanded their scope for DPP4 and beyond.[43]

1.13 Examples of reasons for seeking a reopener are when an EDB experiences a 'catastrophic event' such as an extreme weather event or an earthquake, or when they need to undertake an 'unforeseeable major capex project'. Similarly, EDBs may seek a reopener when there are legislative or regulatory requirement changes, for example, amendments to the Electricity Authority's (EA) Electricity Industry Participation Code 2010.[44]

1.14 **Large Connection Contracts (LCC)** are a new addition to the DPP/CPP regime introduced in the 2023 IM Review, as an optional mechanism that provides an alternative to a reopener for large new customer-initiated and funded connections that meet certain criteria. LCCs can address connection forecast uncertainty in situations where the EDB and connecting party agree in writing that the terms and conditions of the contract between them are reasonable and can apply where a large new connection project has not been provided for in DPP/CPP allowances and meets the required thresholds.

1.15 **CPPs** are an integral part of the default/customised regime under Part 4 and provide the EDB with an option to move to a customised path to better meet its particular circumstances. Given the substantial uplift in expenditure that some EDBs have forecast for the DPP4 period, we expect that some EDBs may require a CPP.

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[43] Commerce Commission "CPP and in-period adjustment mechanisms topic paper: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), paragraphs X5, X42-X44.

[44] Certain types of Code amendments would also be covered under the provisions of s 54V of the Commerce Act.

Other relevant regulatory tools

Information disclosure regulation

1.16 The information disclosure (ID) requirements we set for all EDBs help stakeholders assess whether the purpose of Part 4 regulation is being achieved. Earlier this year, we completed a targeted review of EDB ID requirements to reflect the changing context of decarbonisation and a need for greater network resilience.[45] We have expanded ID requirements to capture more information on network constraints, the use of non-network solutions, pricing, quality of service and asset management. We are also currently implementing consequential changes to ID requirements following the 2023 IM Review. The final decision for these changes is expected to be published by the end of November 2024, to take effect from April 2025.

Broader regulatory landscape

1.17 Our DPP4 decisions seek to encourage EDBs to plan and deliver efficient investment, innovate, and meet quality standards for services to benefit consumers. We work closely with the EA to ensure our work programmes are aligned. Our DPP4 final decisions are complemented by the EA's work that looks at the regulatory settings for distribution networks, including:

1.17.1 the requirements, pricing methodologies, and processes for new and expanding network connections;[46]

1.17.2 how to ensure flexibility providers have access to data about network flexibility opportunities;

1.17.3 how to enable EDBs to see, and signal, current and impending congestion; and

1.17.4 the review of the common quality obligations in the Code.

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[45] Commerce Commission "Targeted Information Disclosure Review (2024) Electricity Distribution Businesses - Final decisions reasons paper" (29 February 2024).

[46] Electricity Authority "Distribution connection pricing: proposed Code amendment. Consultation paper" (24 October 2024), and Electricity Authority "Network connections project: stage one amendments. Consultation paper (25 October 2024).

Explanation of how we have used numbers in this document

1.18 The revenue path and expenditure allowances we determine are required to be specified in nominal terms.[47] Consumers also face costs in nominal dollars. In this document we present allowances for the DPP4 period and compare our allowances to EDB AMP forecasts for DPP4 in nominal terms.

1.19 When explaining trends in revenue over time, we do so in the terms that will apply at the start of DPP4 on 1 April 2025. As this relates to disclosure year 2026, and as we deflate revenue to 2026 dollars terms using the consumer price index (CPI) as a measure of economy-wide inflation, this comparison is in 'real 2026' terms.

1.20 When explaining how we have built up our expenditure allowances, we do this in 2024 constant dollar terms. This enables like-for-like comparisons between expenditure over time, and comparisons between regulatory period allowances. We translate expenditure to 2024 price terms using the same approaches used to set DPP4 allowances for increases in input costs (ie, cost escalation indices relevant to opex and capex with adjustments for input cost growth above these indices). For the purposes of comparison, DPP3 allowances are escalated using the consumer price index as a measure of economy-wide inflation. In all cases, we clarify the terms being used.

[47] Both the revenue path and IRIS expenditure incentives include adjustments for the impact of actual inflation differing from forecast inflation.

Chapter 2 Enabling EDBs to spend and invest to meet forecast consumer demands

Purpose of this chapter

2.1 This chapter:

2.1.1 explains the challenge of enabling EDBs to spend and invest to meet consumer demands;

2.1.2 identifies, and briefly explains, the rationale for each of the final decisions which relate to:

2.1.2.1 DPP regulatory period length;

2.1.2.2 capital expenditure (capex);

2.1.2.3 operating expenditure (opex); and

2.1.3 directs readers to further information about the regulatory period length (see **Attachment H**) and the development of the capex and opex final decisions (see **Attachments B** and **C**).

The challenge of enabling EDBs to make investments to meet consumer demands

2.2 EDBs who are investing and operating efficiently will be planning to meet expected current and future consumer demands on a least-cost lifecycle basis, which includes investing ahead of demand or in larger increments where it is prudent. Our regime acts as a whole to align EDB interests with the long-term benefit of consumers, including providing incentives for the EDB to select the lowest cost approach to meet consumer demand and quality standards, once allowances have been determined.

2.3 We set expenditure allowances to reduce the risk to consumers that EDBs' forecasts may be too high, or overly ambitious to deliver. A DPP is intended to be a relatively low-cost way of setting price-quality paths and therefore may be unsuitable in certain circumstances, such as a significant step change in investment or where there is a high level of uncertainty in underlying investment drivers.[48]

2.4 There are specific tools (reopeners and CPPs) in the regime that enable uncertain or large step increases in expenditure to be appropriately assessed.[49] EDBs may choose to make greater use of these tools, if their investment need is greater than provided for upfront by the DPP reset and they are able to demonstrate that this is unable be accommodated within revenue limits. See **Chapter 1**.

2.5 We expect EDBs to manage within DPP revenue limits first, including through reprioritising expenditure where appropriate, before seeking additional funds through flexibility mechanisms. As with expenditure allowances used to reset revenue limits, increases to limits sought through flexibility mechanisms during the DPP regulatory period need to be appropriate and benefit consumers.

2.6 An appropriate flexibility mechanism needs to be used so that the additional expenditure required receives the appropriate level of scrutiny. For example, significant step changes in investment will likely merit greater scrutiny, and so may be more appropriate as a CPP rather than a reopener.[50]

2.7 Setting allowances for DPP4 is particularly challenging because we are doing this within the context of an energy sector that is in a period of change and uncertainty. Where, when and how much investment will be required by EDBs will depend on a number of factors, including:

2.7.1 how consumer demand evolves;

2.7.2 how EDBs' strategies for meeting demand for electricity lines services adapt with increasing availability of non-network solutions including demand response and distributed energy resources (DER);

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[48] Section 53K of the Act states: The purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

[49] See **Chapter 1** for more about the price-quality regulatory toolkit.

[50] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clauses 4.5.13(1)(d) and 4.5.14(1)

2.7.3 expected improvements to investment information (eg, network risk modelling and demand forecasts); in particular, by incorporating better information on low voltage networks into investment planning, and how this information is reflected in renewal and growth/enhancement investment decisions; and

2.7.4 what investments are needed to enhance network resilience, including evolving government policy guidance around climate change adaptation.[51],[52]

2.8 A price-quality determination provides a revenue allowance, but not a cap on what can be spent. It also does not specifically allocate expenditure to particular categories. While we determine opex and capex allowance separately given their different drivers, EDBs have the flexibility under our regime to substitute between opex and capex responses where they can make cost savings by doing so.

2.9 This gives EDBs flexibility to reprioritise expenditure to respond to a change in circumstances, including changing allocations between opex or capex solutions. We consider there may be greater opportunities in the short to medium term for opex solutions (such as purchasing demand response or flexibility products) where previously a capex investment would be made.

2.10 In addition to flexibility to reprioritise expenditure the DPP has features which respond to the issue of efficient investment choices, which will continue to apply in DPP4. In particular:

2.10.1 the regime incentivises innovation where it results in a lower cost to serve, as EDBs retain a proportion of any efficiency gain;

2.10.2 the IRIS mechanism equalises the strength of the financial incentive to be efficient across the regulatory period; and

2.10.3 our final decision is to maintain equal incentive strength across opex and capex, ensuring that EDBs are incentivised to choose the most efficient solution regardless of expenditure category (see **decision I1** in **Chapter 3**).

[51] Ministry for the Environment "Aotearoa New Zealand's First National Adaptation Plan" (August 2022).

[52] Ministry for the Environment "Adaptation framework" (October 2024).

2.11 Similarly, the INTSA scheme is intended to encourage EDBs to undertake more projects that have benefits that are sufficiently uncertain that they might not otherwise be undertaken, as well as projects where it is unlikely that EDBs would otherwise receive any financial benefits in the five years after the date by which the EDB expects to have completed the project (**decision U1**). In each of these cases we consider that these projects are likely to carry potential benefits for consumers. The INTSA is further discussed in **Chapter 3**.

Final decision for DPP regulatory period length

2.12 Section 53M(4)(5) of the Act allows us to reduce the regulatory period from five years to four years where we consider this would better meet the Part 4 purpose.[53] **decision X1** is for the next regulatory period to be five years. Maintaining the regulatory period at five years provides regulatory continuity for EDBs and prevents the need for EDBs to incur the administrative costs of a reset earlier than usual. See **Attachment H**.

2.13 The submissions we received agreed that retaining the regulatory period length was the best approach. They acknowledged that the benefits of providing regulatory certainty and continuity outweigh the administrative costs associated with reducing the period.[54]

Final decisions for Capex

Capex allowances

Total capex allowance across EDBs

2.14 Our final decision for capex includes an allowance of $6.4 billion (nominal, net of capital contributions) for DPP4. The allowance is $1.2 billion (nominal) or 17% less than EDBs' 2024 asset management plan forecast of $7.6 billion for the DPP4 period.[55]

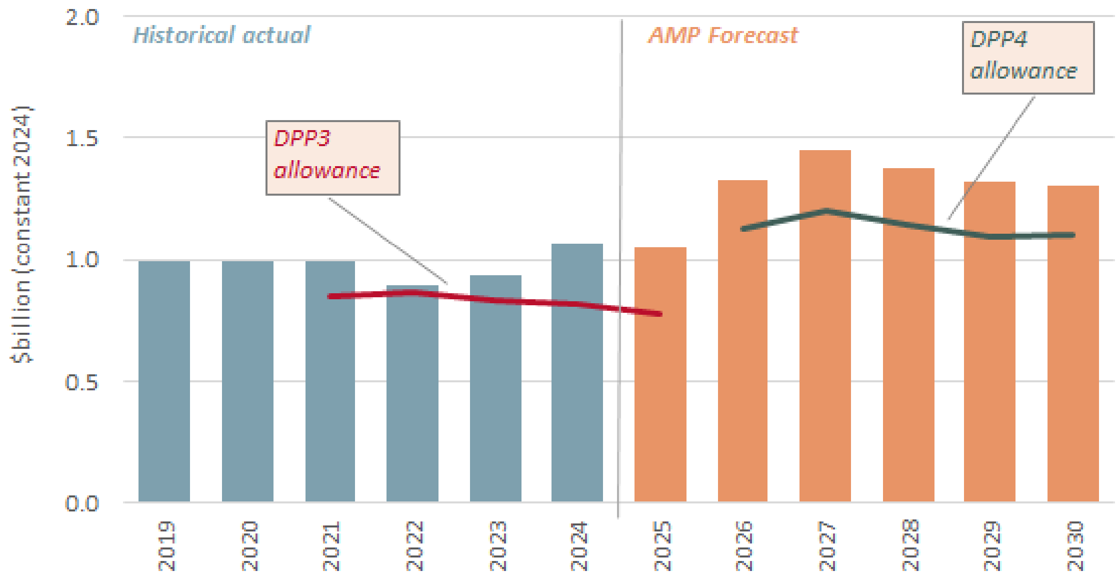
[53] Commerce Act 1986, s 53M(4)(5) and s 52A.

[54] Submissions by ENA, Orion and Vector on the Commerce Commission "EDB DPP4 draft decision" (12 July 2024).

[55] Capex allowances are based on forecast capex (net of capital contributions).

2.15 Comparing between regulatory periods in 2024 constant dollars (see Figure 2.1), the DPP4 capex allowance of $5.7 billion is $1.5 billion or 37% higher than the DPP3 allowance of $4.1 billion.[56] While we have set a higher allowance, we have not set it as high as EDBs have forecasted in their 2024 asset management plans (AMPs). We consider this is appropriate given EDB AMPs reflect large uplifts driven by expenditure drivers that are subject to significant uncertainty due to the evolving environment. We also have reservations about the deliverability of the large increases signalled in AMPs for DPP4, including the feasibility of such large increases ramping up over a relatively short time frame and the uncertainty in growth projections.

Figure 2.1 Capex profile with DPP4 and DPP3 allowances (constant 2024$)[57]



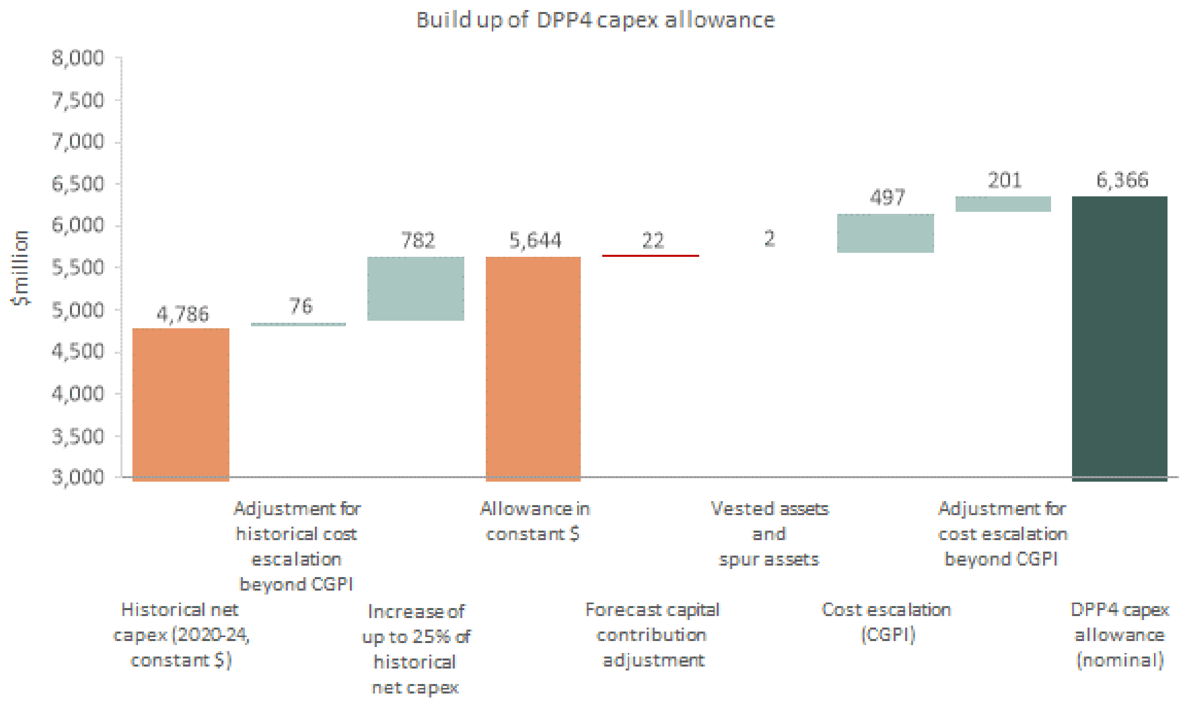
Total capex allowance components

2.16 The components of the DPP4 capex allowance are summarised in Figure 2.2.

[56] DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

[57] Capex allowances are based on forecast capex, established net of capital contributions. DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

Figure 2.2 Components of the DPP4 capex allowance (nominal $ million)



2.17 Key differences in our approach to setting DPP4 ex ante capex allowances compared to the approach used for DPP3 are:[58]

2.17.1 The final decision provides for a maximum increase of 25% relative to the 2020 to 2024 reference period (in constant dollars, net of capital contributions). The result of applying the 25% limit, whereby EDBs either get their 2024 AMP forecast or a 25% uplift (whichever is lower), is a 16% or $782m (constant 2024$) increase above the reference period capex. For DPP3, we limited increases to 20% of the reference period capex.[59]

[58] For all EDBs combined the DPP4 allowance is 37% higher than the DPP3 allowance (in constant 2024 price terms). We note that this percentage difference is not directly comparable to the explanation of the percentages in this paragraph, which focuses on key differences in input assumptions between DPP4 and DPP3. Capex in the DPP4 reference period (2020 to 2024) is generally higher than the DPP3 reference period, when compared in constant dollars. Accordingly, some of the increase in DPP4 allowances compared to DPP3 is attributable to applying the input adjustments to a higher base value.

[59] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), paragraphs B73-B88.

2.17.2 Based on evidence of higher capital goods price inflation (CGPI) for EDBs than in the general economy, we applied adjustments for input price growth beyond the All-Groups CGPI, which as for previous resets, continues to be our preferred cost index. The adjustment of 0.8% per year on top of the All-Groups CGPI, to historical net capex and to forecast cost escalation, results in an additional allowance amount in nominal terms of $277m ($76m from the adjustment to historical net capex and $201m to forecast escalation). For DPP3, cost escalation was a less material issue and we did not provide for adjustments.[60]

Capex allowances per EDB

2.18 The capex allowances for each EDB that result from our final decisions are summarised in Table 2.1.

[60] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), paragraphs B161-B166.

Table 2.1 DPP4 capex allowances (nominal $ million)

EDB	2026	2027	2028	2029	2030	DPP4 Total
Alpine Energy	33.8	31.6	28.6	25.6	30.2	149.9
Aurora Energy[61]	66.6[62]	97.6	110.4	111.7	111.7	497.9
EA Networks	18.6	16.0	16.1	16.0	16.2	82.8
Electricity Invercargill	6.9	9.3	9.9	8.2	9.8	44.1
Firstlight Network	18.6	18.9	14.9	17.2	16.7	86.3
Horizon Energy	11.8	13.8	13.4	12.3	12.2	63.5
Nelson Electricity	2.3	2.7	2.9	2.5	2.5	12.8
Network Tasman	25.3	21.6	19.2	16.9	17.0	100.1
Orion NZ	120.4	147.7	140.5	147.4	151.5	707.4
OtagoNet	23.5	32.5	33.3	36.0	37.7	163.1
Powerco	309.8	332.5	361.3	369.7	387.9	1,761.1
The Lines Company	29.4	27.2	23.5	24.9	24.0	129.0
Top Energy	26.2	24.2	24.6	25.3	24.4	124.7
Unison Networks	82.7	93.8	91.1	93.8	114.6	475.9
Vector Lines	356.2	347.8	303.6	263.1	271.3	1,542.0
Wellington Electricity	63.8	98.9	93.1	94.1	75.8	425.7
Total	**1,195.7**	**1,316.1**	**1,286.5**	**1,264.5**	**1,303.6**	**6,366.4**

2.19 The DPP4 capex allowance in constant and nominal dollars is included in Table 2.2. Table 2.2 also compares the final decision DPP4 capex allowances with DPP3 allowances.

[61] The values included for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from its CPP to the DPP, with its CPP ending 31 March 2026.

[62] The 2026 value here is from the Aurora Energy CPP.

Table 2.2 Comparison of DPP3 and DPP4 capex allowances ($ million)[63]

EDB	DPP3 period capex allowance (constant 2024 $)	DPP4 capex allowance (constant 2024 $)	DPP4 allowance for input price inflation (nominal $)	DPP4 capex allowance (nominal $)
Alpine Energy	83.5	133.9	16.0	149.9
Aurora Energy[64]	367.8	441.1	56.8	497.9
EA Networks	90.4	73.9	8.9	82.8
Electricity Invercargill	27.6	39.2	4.9	44.1
Firstlight Network	51.5	77.1	9.3	86.3
Horizon Energy	42.8	56.6	6.9	63.5
Nelson Electricity	8.9	11.4	1.4	12.8
Network Tasman	53.8	89.7	10.4	100.1
Orion NZ	413.8	628.8	78.6	707.4
OtagoNet	87.4	144.5	18.5	163.1
Powerco	1,151.3	1,564.5	196.6	1,761.1
The Lines Company	88.9	115.3	13.8	129.0
Top Energy	84.1	111.2	13.5	124.7
Unison Networks	261.3	422.5	53.4	475.9
Vector Lines	1,112.2	1,380.0	162.0	1,542.0
Wellington Electricity	217.7	378.8	46.9	425.7
Total	**4,142.8**	**5,668.4**	**698.0**	**6,366.4**

2.20 For all EDBs combined the DPP4 allowance is 37% higher than the DPP3 allowance (in constant 2024 price terms), with significant variation across EDBs. This illustrates that despite some EDBs getting an allowance significantly below their forecast (as shown in Figure 2.3), DPP4 allowances generally are significantly above DPP3 allowances.

2.21 Table 2.3 shows the final capex allowances for EDBs compared to their draft capex allowances.

[63] DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora Energy, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

[64] The values included for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from its CPP to the DPP, with its CPP ending 31 March 2026.

Table 2.3 Changes in capex allowances (nominal $ million)

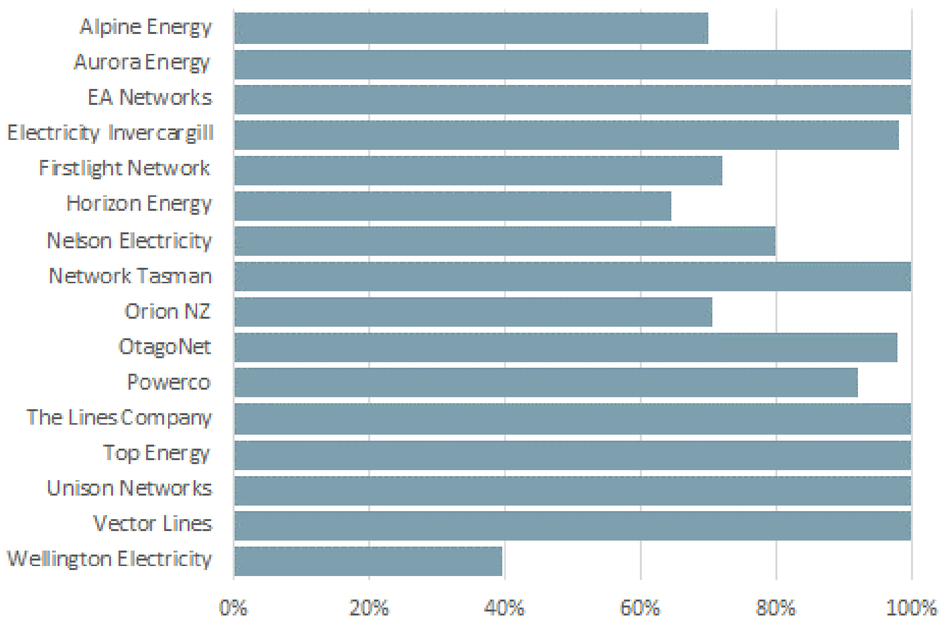
EDB	Capex allowance ($m)	Draft Capex allowance ($m)	Change ($m)	Change (%)
Alpine Energy	149.9	145.9	4.0	2.8%
Aurora Energy	497.9	498.6	-0.7	-0.1%
EA Networks	82.8	83.0	-0.1	-0.2%
Electricity Invercargill	44.1	43.6	0.5	1.2%
Firstlight Network	86.3	87.2	-0.8	-0.9%
Horizon Energy	63.5	77.9	-14.4	-18.4%
Nelson Electricity	12.8	14.0	-1.2	-8.5%
Network Tasman	100.1	100.3	-0.2	-0.2%
Orion NZ	707.4	667.8	39.6	5.9%
OtagoNet	163.1	164.2	-1.1	-0.7%
Powerco	1761.1	1790.2	-29.0	-1.6%
The Lines Company	129.0	129.3	-0.2	-0.2%
Top Energy	124.7	134.4	-9.7	-7.2%
Unison Networks	475.9	420.4	55.5	13.2%
Vector Lines	1542.0	1521.1[65]	20.9	1.4%
Wellington Electricity	425.7	422.8	2.8	0.7%
Total	**6366.4**	**6300.5**	**65.9**	**1.0%**

2.22 More significant changes to capex allowances between the draft and final decision are driven by updating the reference period to 2020 -2024 (for the final decision) from 2019-2023 (used for the draft decision). Other more minor changes to allowances arise because of updates to All-Groups CGPI and in some instances changes to the levels of capital contribution adjustments.

[65] Vector's draft capex allowance is as published in Table B1 of Attachment B of our DPP4 Draft decision reasons paper. This draft capex allowance is as published but incorrect, as it reflects the adjustment for forecast capital contributions that was inadvertently applied in the modelling at draft decision. We have retained the as-published draft capex allowance in this table purely for the purposes of comparison with final allowances. This means that the change ($m) and change (%) numbers for Vector in this table are overstated.

2.23 Figure 2.3 expresses the DPP4 allowance as a proportion of each EDB's 2024 AMP forecast. Our final decision means that most EDBs will have allowances that are 70% or more of their capex forecast, which includes over half having allowances of at least 90% of their forecasts. Two EDBs will have allowances of less than 70% of their forecast. As mentioned above, where an EDB considers the ex-ante DPP allowances do not meet their needs, they are able to make use of reopeners where appropriate or consider applying for a CPP.

Figure 2.3 DPP4 capex allowance as proportion of EDBs' AMP forecasts (constant 2024$)



Context for DPP4

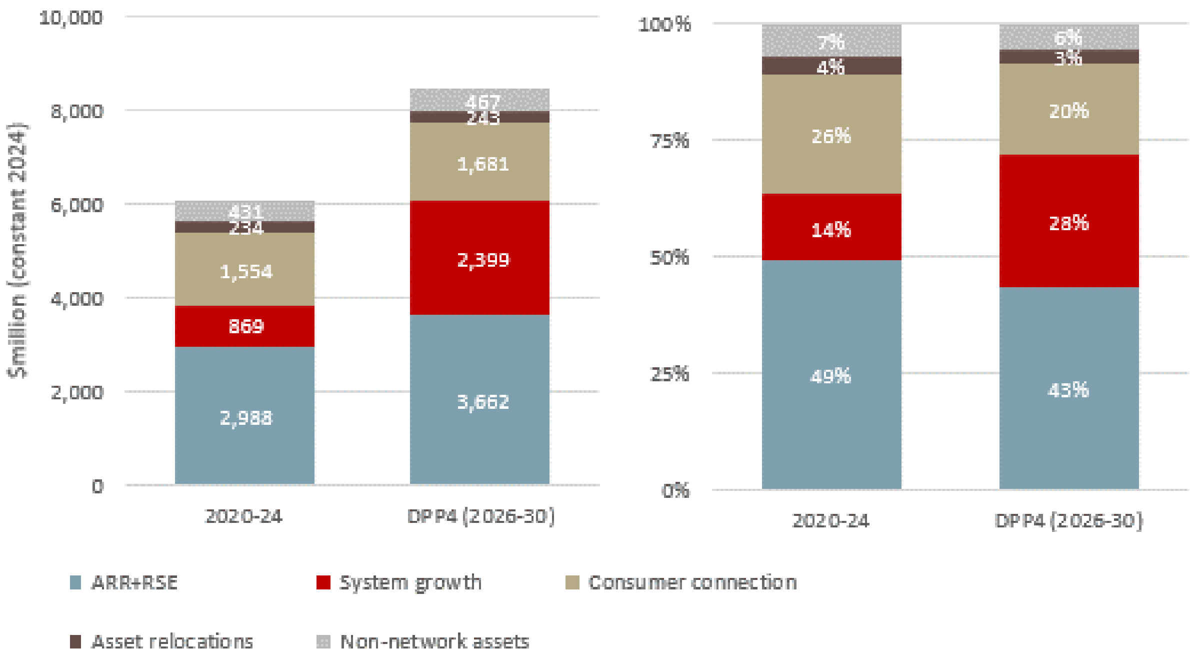
2.24 There are significant challenges and uncertainty for the energy sector to respond to over the next five to ten years. Given the context of change, unknowns regarding pace, constrained labour market, supply chain challenges, and the forecast uplift in investment indicated in AMPs, we have been particularly interested in understanding:

2.24.1 how EDBs have responded to these challenges and the uncertainty this has created in their forecasts; and

2.24.2 the deliverability of elevated work programmes at a sector and individual EDB level.

2.25 The total AMP forecasts (in constant dollar terms) gross of capital contributions for all non-exempt EDBs for DPP4 is $8.5 billion compared with actual spend of $6.1 billion from 2020 to 2024. Figure 2.4 shows total capex (forecast and actual) on assets by category in constant 2024 dollars and spend as a proportion of total capex (before deduction of capital contributions). The forecast shows that both lifecycle renewal and system growth capex are expected to significantly increase in DPP4, with system growth forecast to have the largest increase across EDBs combined. There is also great diversity across EDBs, both in the size and makeup for the forecast uplift.

Figure 2.4 Composition of capex – forecast (DPP4 period) vs actual (2020-2024) in $m and as a percentage of total capex[66] [67]



2.26 We have considered how the DPP allowance setting process could accommodate the elevated investment profile in a way that enables prudent investment and mitigates risks to consumers.

2.27 The next section covers the two alternative approaches we explored for setting capex allowances, before deciding on the approach used for the final decision.

[66] ARR is short for asset replacement and renewal, and RSE is short for reliability, safety and environment.

[67] The numbers in this graph refer to gross capex spend, before capital contributions are deducted

We were unable to get assurance on reasonableness of all EDB capex forecasts in a relatively low-cost way

2.28 In the DPP4 Issues and draft reasons papers, we acknowledged that EDBs have told us that past expenditure is not a good basis for assessing future capex and there was a view that there should be a greater reliance on EDBs' AMP forecasts to set allowances. We undertook targeted reviews of AMPs to understand whether we could make greater use of these for setting DPP4 allowances. [68]

2.29 Innovative Assets Engineering (IAEngg) were commissioned to support the review of the 2023 AMPs.[69] As part of that review, they were asked to identify and analyse key drivers of change, uncertainties, and variables in financial and demand forecasts to enable them to provide an independent opinion on the reasonableness of the variations contained in EDBs' 2023 AMPs.

2.30 We were not expecting the IAEngg review to 'verify' AMP forecasts to be used in our capex framework, but to inform our capex forecasting approach. This included providing confidence in the approaches which EDBs take to setting forecasts.

2.31 In a letter to stakeholders, we noted that the DPP is intended to be a relatively low-cost regulatory tool, and we did not expect that the extent of analysis or level of assurance which would be provided by IAEngg would be at a similar level to CPP proposals, which are supported by independent verification.[70]

2.32 The final IAEngg report provides overall comfort that non-exempt EDBs' capex forecasting approaches as explained in their AMPs broadly align with good industry practice and provide useful insights that informed our approach for capex. However, the review confirmed that the content in AMPs is unlikely to enable opinions to be provided on the reasonableness of EDB expenditure forecasts or provide sufficient comfort for setting allowances at an individual EDB level: [71]

[68] Our targeted AMP reviews relate to 2023 full AMPs rather than the 2024 AMP updates. The 2023 AMPs were the best information available to us at draft decision stage to base targeted reviews on.

[69] IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024).

[70] Commerce Commission "External reviews of electricity distribution businesses' 2023 asset management plans and of efficiency and productivity" (31 August 2023).

[71] IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024), p.73.

> While IAEngg can provide an opinion on the reasonableness of the forecasting approach based on assessing the quality of the forecasting model, we cannot provide an assurance of the forecasting output (volume of assets to be replaced) without examining the model inputs. In the same way, IAEngg cannot provide an opinion on the reasonableness of the expenditure forecast without access to the unit rates used to convert volumes of work into expenditure.

2.33 Submitters' views on the potential use of AMPs to set capex allowances were mixed. Some EDBs submitted, based on their view of the level of assurance that can be derived from the IAEngg report, that AMPs are sufficiently robust that we can adopt or rely on AMP forecasts in their entirety. However, submissions from other stakeholders, including representatives of consumers, indicated low confidence that AMP forecasts could be relied on for setting allowances.[72]

2.34 The IAEngg independent review and our own targeted review of a selection of the 2023 AMPs and responses to the s 53ZD notice indicated to us that it would be inconsistent with a relatively low-cost regime to undertake the level of assessment required to obtain sufficient assurance from AMPs to adopt the full AMP forecasts as capex allowances.[73] Our review also found that AMPs can be an informative source, in some instances, for identifying where flexibility mechanisms were accessible for expenditure that is unlikely to be able to be accommodated within the DPP.

We were unable to identify metrics and thresholds that could help assess forecast capex, in a relatively low-cost way, given the context of step changes and wide-ranging needs

2.35 The uncertain nature, pace and scale of investment needed by EDBs, and the variability across EDBs, in DPP4 compared with past resets means that relatively low-cost analytical approaches that can be consistently applied across all non-exempt EDBs in a meaningful way are difficult to identify.

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[72] See *Extent to which information in AMPs can be relied on to set DPP allowances* section in **Attachment B.**

[73] In addition to submissions on the DPP4 Issues paper on this topic, we used a s 53ZD notice (issued in November 2023) to get early disclosure of draft 2024 AMP capex forecasts and additional information requesting the primary driver for increases in expenditure.

2.36 We tested our emerging views on our capex framework, including metrics and thresholds, at our capex workshop on 26 February 2024.[74] We did not receive any submissions following that workshop that identified new metrics, additional information on the metrics and thresholds or alternative analytical approaches that changed our view about the application of these in our approach. We did not receive any submissions on our draft decision that suggested metrics, thresholds or alternative approaches.[75]

2.37 We concluded that the application of metrics and thresholds would not allow us to form a view within the DPP on whether capex forecasts in asset management plans are reasonable (or prudent and efficient).

Our approach for setting capex allowances

2.38 The capex allowance across all regulated EDBs for DPP4 (in nominal dollars, net of capital contributions) is $6.4 billion. The allowance is $1.2 billion or 17% less than EDBs' 2024 AMP forecast of $7.6 billion for the DPP4 period.

2.39 The allowance is based on four main decisions:

2.39.1 Use EDB AMPs as the source for EDB forecast expenditure information (**decision C1**).

2.39.2 Set the capex allowance (net of capital contributions) in constant dollars based on the lower of an EDB's total net forecast capex or 125% of its historical reference period net capex, with a subsequent adjustment for changes in forecasted levels of capital contributions for capped EDBs (**decision C2**).

2.39.3 Set the capex allowance relative to an adjusted five-year historical reference period of 2020 to 2024. The historical data are escalated using the All-Groups CGPI with an additional cost escalation adjustment (**decision C3**).

2.39.4 Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to nominal terms (**decision C6**).

[74] Commerce Commission "Capital expenditure framework design – workshop" (26 February 2024).

[75] See *We were unable to identify metrics and thresholds that could help assess forecast capex, in a relatively low-cost way, given the context of step changes and wide-ranging needs* section under **decision C2** in **Attachment B**.

2.40 In addition to the main decisions, similar to DPP3, the final allowance also includes an allowance for the cost of finance, scaled in proportion to the capex allowance (**decision C4**). No separate allowances were provided for spur assets, an allowance for the value of considerations for vested assets as identified is included (**decision C5**).

2.41 The main **decisions C1, C2, C3 and C6** are summarised in this section and explained in detail in **Attachment B**. **Decisions C4** and **C5** being more minor, are not summarised in this section and are only discussed in **Attachment B.**

2.42 Our capex final decisions have been informed by insights from our targeted reviews of 2023 AMPs, assessment of the feasibility of approaches consistent with a relatively low-cost DPP, submissions received, information provided in response to the s 53ZD notice and 2024 AMPs.

Decision C1*: Use EDB AMPs as the source for EDB forecast expenditure information*

2.43 While we consider it is not appropriate to set capex allowances at the value of expenditure forecasts contained within the AMP, they remain a useful source of EDB forecast expenditure information in the context of a relatively low-cost regime. EDBs are in a good position to understand the needs of their consumers and communities, and they ought to understand the health of their assets, the risks to delivering safe and reliable electricity, and what is required to manage those risks. This information should be represented within their AMP.

2.44 We note that both the 2023 AMPs and the 2024 AMP updates by their nature have been produced at a point in time and reflect a range of assumptions and scenarios which may occur at a different pace in a relatively dynamic economic and policy environment.

2.45 The view that AMPs are an appropriate source for EDB forecast information was generally supported by stakeholders and informed our final decision to use EDB AMPs as the source for EDB forecast expenditure information.[76]

Decision C2*: Set the capex allowance (net of capital contributions) in constant dollars based on the lower of an EDB's total net forecast capex or 125% of its historical reference period net capex, with a subsequent adjustment for changes in forecasted levels of capital contributions for capped EDBs.*

[76] See **decision C1***: Use EDB AMPs as the source for EDB forecast expenditure information* section in **Attachment B**.

2.46 We have a range of options we could have used to determine the capex allowances for DPP4. This includes relying, wholly or partly, on the capex forecasts in AMPs, setting a limit on total capex, applying different limits to different categories of spend, and setting different limits for different groups of EDBs. The options can be applied at an aggregate or category level and defined in dollar or percentage terms.

2.47 Our final decision for DPP4 is to set capex allowances by limiting total forecast net capex to 125% of historical net capex (based on a historical reference period of 2020-2024, compared with our draft decision which used 2019-2023 as the reference period), with a subsequent adjustment for changes in forecasted levels of capital contributions for capped EDBs.

2.48 This differs from our approach in DPP3 where we applied caps at category level before applying an overall cap of 120%. This meant that ten EDBs were capped on individual categories before the 120% overall cap was applied. The 120% cap reflected the point at which we considered the cost impact on consumers justified further assessment of expenditure and was likely to be more appropriate to assess as a CPP application.[77]

2.49 Given the context for DPP4, and the information that is available to us, we consider a single cap applied to total capex is consistent with the relatively low-cost nature of a DPP and the high degree of uncertainty affecting expenditure forecasts at a category level.[78] Setting a cap for total capex acknowledges, and provides for, EDBs having different investment profiles and priorities and enables deliverability and resilience to be considered at an aggregate level.

2.50 We considered applying caps at a capex category level but, in contrast to DPP3, have opted to apply an aggregate cap to avoid:

2.50.1 addressing inconsistencies in how EDBs classify expenditure across different capex categories; and

2.50.2 unintended consequences of constraining EDBs that run cyclical programmes for different types of works.

[77] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), see **Attachment B**.

[78] Total capex is the sum of net capex for all categories of capex.

2.51 We consider a maximum increase of 25% is appropriate given the context for DPP4 of large uplifts with ranging need, evolving environment, key drivers that are subject to significant uncertainty, limited information to understand drivers for the uplift and deliverability challenges facing the sector. We consider within the context of the DPP and the availability of reopeners and CPPs, a maximum increase of 25% will promote incentives to invest while limiting EDBs' ability to extract excessive profits.

2.52 In forming our view, we:

2.52.1 analysed past step increases in capex, deliverability insights from independent reports, and considered the increase provided for in DPP3 to form a high-level view of the level of expenditure that is likely to be deliverable;

2.52.2 analysed input cost trends, to determine an appropriate uplift to historical capex spend to enable these to be an appropriate basis for comparison with forecast capex;

2.52.3 considered our findings from targeted reviews of AMPs, and insights from the IAEngg report which provided an expert opinion that EDBs' forecasting practices broadly align with good industry practice which gives some comfort in providing for an additional increase in allowances;

2.52.4 considered the implications for EDBs of having capped forecasts; and

2.52.5 considered submissions received on our draft decision on the 125% cap which included:

2.52.5.1 EDB views that resulting allowances may be insufficient to accommodate required investment, the limited impact of higher capex allowances on consumer bills and the risk of increased reliance on reopeners; and

2.52.5.2 Non-EDB views that the cap should be lower than 125% or held at historical levels because investment requirements are not appropriately justified or do not take into account non-network solutions.[79]

[79] See Component 2 of **Decision C2**: *Cap the increase in total net forecast capex to 125% of historical reference period net capex* section in **Attachment B**.

2.53 The decision to set the cap at 125% considered the role of the DPP within the broader price-quality regime, the flexibility mechanisms available to EDBs within the regime and the risk to consumers of setting allowances too high or low.

2.54 Our view is that a 125% cap is appropriate and that the long-term benefit of consumers would be better served through flexibility mechanisms such as reopeners and CPPs for additional allowances. This manages the risk that consumers pay for investments that are not efficient or are potentially not delivered. We accept that there will likely be higher uptake of these flexibility mechanisms during DPP4 than in previous regulatory periods.

2.55 The impact of additional capex allowances on allowable revenue and consumer prices may be relatively small in DPP4 but consumers will still end up paying for assets over the life of the assets, ie over a long period of time. In the short-term, capex impact on revenue and consumer bills may be more limited, but if higher capex allowances were set to reflect elevated work programmes which are not delivered, EDBs would receive IRIS benefits which may be significant.

2.56 Our view is that setting the cap at 125% of historical reference period net capex reflects that a number of EDBs are facing increased levels of expenditure required to maintain and deliver a safe, reliable and resilient network capable of supporting increasing electrification compared to previous levels. We considered whether the cap could be set lower than 125% but consider that doing so would likely result in a higher reliance and burden on flexibility mechanisms during the period to justify expenditure which is likely in the long-term benefit of consumers. We consider that this would be inconsistent with a relatively low-cost regime.

2.57 The price-quality path provides a revenue allowance, but not a cap on what can be spent. EDBs are also able to operate within their revenue limits, by reprioritising and substituting between opex and capex, given these are fungible and have equalised incentives.

2.58 Changes in the level of capital contributions between periods, due to either a change in capex composition or change in policy, can have a material effect on the overall funding available for capex. For EDBs that have net forecast capex increases greater than 125%, an adjustment is applied to the capex forecast to reflect each capped EDB's forecast change in level of capital contributions relative to the reference period, appropriately scaled.

Decision C3: *Set the capex allowances relative to an adjusted five-year historical reference period of 2020 to 2024*

2.59 Our DPP4 Issues paper noted we were proposing to adapt our approach to capex for DPP4 based on feedback from EDBs, that past expenditure is not a good starting point for considering future spend.[80] The use of a reference period does not require that the values are capped at historical levels, we are able to consider changes to account for differences in underlying demand or cost factors across time periods.

2.60 Without reference to a historical reference period, it would be difficult to understand the relative scale of change. EDBs have wide variability in the size and nature of their networks, consumer base, and how they respond to drivers. Using past expenditure enables us to reflect these characteristics in a relatively low-cost way and is also reflective of each EDB's baseline capacity to deliver.

2.61 Feedback from submissions on the DPP4 Issues paper indicated that stakeholders understood the need for this approach given the relatively low-cost nature of the DPP. There were no submissions that objected to the use of a historical reference period for assessment purposes. This feedback was reinforced in submissions to the draft reasons paper, where submitters were generally supportive of the five-year historical reference period.[81]

2.62 Based on our analysis of historical trends and consideration of feedback from interested stakeholders, our final decision is to use a reference period of five years, ie, 2020 to 2024. The five-year period reflects the higher capex profiles of EDBs post the COVID-19 period and is of sufficient length to minimise the extremes for individual EDBs and smooth out volatility. This compares to the seven-year reference period used in DPP3.

2.63 EDBs have also told us that they experienced higher input prices in recent years and that this increase has been reflected in their capex forecasts.[82] Our analysis of price indices and other alternative sources of evidence, confirms that some form of adjustment to the reference period is warranted in order to accommodate these higher input prices.

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[80] Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), p. 27.

[81] See *What we heard from stakeholders on choice of reference period* section under **decision C3** in **Attachment B**.

[82] See *Recent input price pressures* section under **decision C3** in **Attachment B**.

2.64 In establishing comparative values for the reference period which account for the impact of price inflation, our final decision is to inflate the historical reference period values by the All-Groups Capital Goods Price Index (All- Groups CGPI) plus an additional 0.8% per annum.

2.65 Our cost inflation decisions for the reference period (All-Groups CGPI as price index and an additional adjustment of 0.8% per annum) are consistent with the cost inflation approach for expenditure allowances (**decision C6**). The supporting analysis and rationale for both cost inflation decisions are set out in the **decision C6** section below.

Decision C6*: Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to nominal terms*

2.66 An appropriate cost escalation index is needed to express the capex allowance in nominal terms (and express the historical reference period capex in constant terms for **decision C3**). In DPP3, we used NZIER's forecast for the All-Groups CGPI to escalate the capex allowance from constant to nominal dollars.[83]

2.67 Based on our analysis of other indices, including sub-indices identified as being appropriate for an EDB index and based on feedback from submissions, our final decision is to use the All-Groups CGPI forecast to escalate the capex allowance from constant to nominal dollars for DPP4 (same price index applied for reference period capex in **decision C3**). Although there were initial requests by a couple of submitters for more targeted customised indices, the All-Groups CGPI was generally supported by draft decision submissions, with submitters recognising the complexity associated with forecasting an EDB-specific CGPI.[84]

2.68 Our analysis of the All-Groups CGPI and the CGPI- Construction of Electricity distribution lines (EDB-specific CGPI), showed that over the 2019-2023 period, the EDB-specific CGPI has been tracking on average 0.8% per annum higher than the All-Groups CGPI.

[83] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019) , paragraphs B161-B166.

[84] See *Choice of cost escalation index - Analysis* section in **Attachment B** for further details.

2.69 In forming our decision to apply an adjustment, we also analysed information collated by Electricity Networks Aotearoa (ENA) on the cost inputs from its members, average historical variances between the All-Groups CGPI and the EDB-specific CGPI, Powerco's CPP annual delivery reports, and Energy Network Consulting's Aurora Energy's CPP mid-period review report.[85, 86, 87, 88] We also considered a cost escalation report from Oxford Economics Australia (OEA), jointly commissioned by Orion, Vector and Wellington Electricity.[89] Analysis of this report identified the escalation adjustment is highly sensitive to the time period selected which is subjective. Our analysis showed that our cost escalation approach of using the All-Groups CGPI and the additional 0.8% adjustment on average is higher than the cost escalation forecasts used by most EDBs in their 2024 AMPs.[90]

2.70 The final decision is to apply an input cost adjustment of 0.8% per annum to the All-Groups CGPI because our view is that additional input price pressures are likely to continue over the short to medium term. The 0.8% per annum figure represents the additional inflation beyond the All-Groups CGPI (the same value as for **decision C3**), which we consider to be a reasonable proxy of future input price pressures that affect EDBs relative to the wider economy.

Other regulatory tools within the DPP/CPP regime

2.71 As mentioned in **Chapter 1**, the DPP reset is one tool in the wider price-quality toolkit. The toolkit also includes flexibility mechanisms such as DPP recoverable costs, pass-through costs, reopeners, LCCs and CPPs. These flexibility mechanisms are available to be used during DPP4 where appropriate and were reviewed and updated in the recent 2023 IM Review.[91]

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85 See *Recent input price pressures* section under **decision C3** in **Attachment B**.

86 The ENA provided aggregated data from a sample (eight of 16) of non-exempt EDBs for the 2019-2023 period on total installed cost and asset replacement quantities for poles, conductors, transformers, cable/line and switches, and average cost trends.

87 Powerco CPP Annual Delivery Reports: 2023, 2022, 2021, 2020, 2019

88 Aurora Energy "CPP Mid-Period Review: Independent Expert Report" (February 2024).

89 OEA "New Zealand Electricity Businesses Labour and Material Cost Escalation" - (Report for Orion NZ, Wellington Electricity and Vector, June 2024).

90 See *Quantum of additional adjustment to the cost escalation index* section under **decision C6**, **Attachment B**.

91 Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), Chapters 6, 8 and 9.

2.72 We received submissions as part of the issues paper and capex workshop process which raised the need for new flexibility mechanisms that are non-reopeners ('other mechanisms'). [92]

2.73 As part of this DPP reset we have not initiated a process to amend the IMs to implement any additional mechanisms. Submissions did not provide further information on how the challenges and limitations with these other mechanisms, which were identified in the IM Review, could be accommodated within a relatively low-cost DPP.[93]

2.74 We also received a large number of submissions on reopeners in particular- sentiments on the workability of reopeners, requests for clarity on reopener practical implementation aspects and for guidance to be issued and suggestions for scope of reopeners to be expanded. We have broadly responded to these points within the *Role of flexibility mechanisms* section in **Attachment B**, noting these points are better addressed through processes outside of the DPP4 reset.

Final decisions for Opex

2.75 Opex allowances enable EDBs to fund recurring activities that are not capex, including activities essential to the network operation such as maintenance and planning.

2.76 Opex has a direct effect on the revenue EDBs can earn, with opex representing about 33% of EDB's net revenue allowances.[94] Before any smoothing that might be applied, revenue limits are set to allow recovery of opex allowances directly via revenue over the regulatory period, whereas capex is added to the RAB and recovered over the life of the asset. From an efficiency point of view, the opex allowance we set is the baseline used, along with actual opex, to determine opex incentive payments or IRIS incentive amounts.

2.77 We first present the final opex allowances, and then discuss key opex decisions.

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[92] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft Reasons paper" (29 May 2024), paragraph B210.

[93] See *No addition of other uncertainty mechanisms* section under *Role of flexibility mechanisms* **Attachment B.**

[94] The exact proportion varies by EDB. See the 'BBAR' sheet in the file "Financial model-EDB DPP4 final determination-20 November 2024.xlsx" published on our website alongside this paper.

Opex allowances

Total opex allowance across EDBs

2.78 Our final decision for opex includes an allowance of $4.1 billion (nominal) for DPP4. The allowance is $0.2 billion or 4% less than EDBs' 2024 asset management plan forecast of $4.2 billion for the DPP4 period.

2.79 The opex allowances for each EDB that result from our final decisions are summarised in Table 2.4.

2.80 Comparing between regulatory periods in 2024 constant dollars, the DPP4 opex allowance of $3.6 billion is $0.6 billion or 22% higher than the DPP3 allowance of $3.0 billion. While we have set a higher allowance, we have not set it as high as EDBs have forecasted in their 2024 asset management plans (AMPs) which total $3.9 billion.

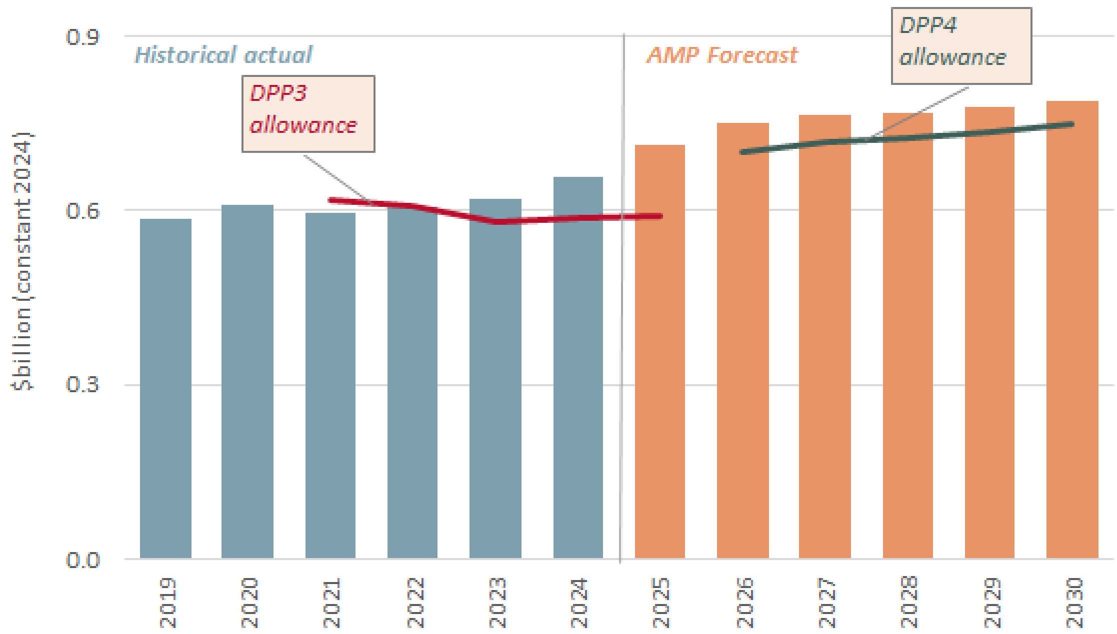
2.81 Figure 2.5 shows the profile of total opex allowances over DPP3 and DPP4, on a 2024 constant price basis.

Table 2.4 DPP4 opex allowances (nominal $ million)

EDB	2026	2027	2028	2029	2030	DPP4 total
Alpine Energy	35.2	36.4	37.8	39.2	40.6	189.2
Aurora Energy [95]	47.6	55.1	56.9	58.9	60.9	279.4
EA Networks	17.3	17.7	18.0	18.4	18.8	90.2
Electricity Invercargill	6.8	7.1	7.3	7.6	7.8	36.6
Firstlight Network	17.2	17.7	18.2	18.8	19.4	91.3
Horizon Energy	14.5	15.7	14.8	15.1	15.6	75.7
Nelson Electricity	2.7	2.8	2.9	3.0	3.1	14.6
Network Tasman	17.1	17.7	18.3	19.0	19.7	91.8
Orion NZ	94.6	98.6	102.9	108.3	112.8	517.2
OtagoNet	11.8	12.3	12.8	13.3	13.9	64.2
Powerco	137.7	143.8	151.2	157.4	164.3	754.4
The Lines Company	20.3	21.2	21.9	22.6	23.3	109.2
Top Energy	26.3	27.1	27.8	28.7	29.5	139.4
Unison Networks	58.1	61.5	62.9	65.9	69.1	317.5
Vector Lines	194.8	202.8	211.3	220.4	229.9	1,059.3
Wellington Electricity	45.2	46.8	48.4	50.2	52.0	242.7
Total	**747.4**	**784.3**	**813.5**	**846.6**	**880.9**	**4,072.7**

[95] The figures for Aurora Energy are indicative only, with the 2026 value from its CPP. They will be finalised when Aurora Energy transitions from their CPP to the DPP, with its CPP ending 31 March 2026.

Figure 2.5 Opex profile with DPP4 and DPP3 allowances (constant 2024$)



2.82 Table 2.5 shows final DPP4 opex allowances for EDBs compared to their draft opex allowances. We received updated information and constructive feedback through submissions on the DPP4 draft decision, and have implemented some changes to the opex allowance as a result. Key changes from our draft decision include:

2.82.1 updating the base year opex from 2024 AMP forecasts to 2024 actuals reported in ID data;

2.82.2 approval of some additional step changes;

2.82.3 the exclusion of a specified amount for insurance and LV monitoring from the aggregate 5% cap on opex step change increases; and

2.82.4 updating LCI and PPI forecasts for the cost escalators.

2.83 These changes are discussed in more detail through the rest of this section and in **Attachment C**.

Table 2.5 DPP4 opex allowances, change from draft to final (nominal $ million)

Distributor	Opex allowance ($m)	Draft Opex allowance ($m)	Change ($m)	Change (%)
Alpine Energy	189.2	177.1	12.0	6.8%
Aurora Energy	279.4	282.3	-3.0	-1.1%
EA Networks	90.2	96.2	-6.0	-6.2%
Electricity Invercargill	36.6	37.2	-0.6	-1.7%
Firstlight Network	91.3	88.2	3.1	3.5%
Horizon Energy	75.7	72.8	2.9	4.0%
Nelson Electricity	14.6	13.1	1.5	11.1%
Network Tasman	91.8	89.6	2.3	2.5%
Orion NZ	517.2	486.8	30.4	6.2%
OtagoNet	64.2	60.6	3.6	5.9%
Powerco	754.4	726.0	28.4	3.9%
The Lines Company	109.2	99.5	9.7	9.8%
Top Energy	139.4	137.3	2.1	1.6%
Unison Networks	317.5	310.9	6.6	2.1%
Vector Lines	1,059.3	1,017.5	41.8	4.1%
Wellington Electricity	242.7	233.5	9.2	3.9%
Total	**4,072.7**	**3,928.6**	**144.1**	**3.7%**

Overall approach to Opex

2.84 Decisions relating to opex are grouped here into:

2.84.1 overall approach and choice of base-year (**decisions starting O1**);

2.84.2 step changes (**decisions starting O2 and O3**); and

2.84.3 trends, including scale input cost escalation (**decisions starting O4**), scale trends (**decisions starting O5**), and opex partial productivity (**decision O6.1**).

Choice of base-step-trend approach and decisions on the base year (O1)

2.85 **Decision O1.1** We have retained from previous resets the base, step, and trend approach used to forecast opex allowances: taking a base level of opex, projecting forward trends, and applying any step changes.[96] This approach is fundamentally sound and appropriate for a relatively low-cost DPP. As discussed further below, we have revised some aspects of how we have applied the base-step-trend approach so that it remains fit for purpose in a changing context.

2.86 **Decision O1.2** Using year four of the current regulatory period (2024) as the opex base year is required for consistency with the opex IRIS IMs.[97] The base year also plays an important role in ensuring opex forecasts reflect EDBs' prudent and efficient costs. Starting our opex forecasts with an updated base year ensures future allowances capture EDBs' current level of operating efficiency, including any changes that have occurred over the DPP3 period. The base year opex for DPP4 final decisions is 2024 operating expenditure, as reported in 2024 ID data.

2.87 These decisions are unchanged from our draft decision.[98] Submissions on the DPP4 Draft decision expressed a range of views on the base step trend approach, which we respond to at the top of **Attachment C**. Notably, ENA supported the continued use of base-step-trend as appropriate for DPP4[99] while some EDBs (who mostly had lower draft opex allowances than in their AMPs) raised concerns or called for more use of AMP opex forecasts.[100]

Step Changes: step change framework and decisions (O2, O3)

O2: Amend the decision-making framework for assessing step changes

2.88 **Decision O2.1** is to assess step changes against five factors. For a step change to be accepted it does not have to satisfy every factor. Instead, the degree to which the step change satisfies each factor has been considered and weighed in making the final decision. Ultimately, we considered whether a decision to approve the suggested opex step change will promote the Part 4 purpose.

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[96] As noted in the IAEngg report into asset management practices, many EDBs' own AMP opex forecasts apply variations of a 'base, step, and trend' methodology.

[97] Commerce Commission, "Electricity Distribution Services Input Methodologies Determination 2012" (23 April 2024), clause 3.3.5.

[98] Draft decision O1.2 was to use 2024 as the base year with 2024 AMP forecasts used for the draft decision as 2024 ID data was not yet available.

[99] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 8.

[100] For example, submissions by Powerco, Top Energy, Wellington Electricity and Vector on the Commerce Commission "EDB DPP4 draft decision" (12 July 2024).

2.89 This approach is unchanged from our DPP4 Draft decision where it was widely supported.[101]

2.90 The assessment factors we have applied in reaching our final decision are whether the opex step change:

2.90.1 is significant (**decision O2.2**);

2.90.2 is adequately justified with reasonable evidence in the circumstances (**decision O2.3**);

2.90.3 is not captured in the other components of the DPP allowance (**decision O2.4**);

2.90.4 has a driver outside the control of a prudent and efficient supplier (**decision O2.5**); and

2.90.5 is widely applicable (**decision O2.6**).

2.91 We have changed these assessment factors from DPP3 following feedback received in submissions on the DPP4 Issues paper and to the changing context within the electricity sector. A number of submitters on the DPP4 Issues paper stated the opex step change decision-making criteria applied in DPP3 were too strict. They stated that some declined step changes for new activities were nevertheless undertaken by EDBs during DPP3.[102]

2.92 While we note that EDBs choosing to prioritise particular opex is not necessarily evidence of a framework problem, we have amended the decision-making approach to be more flexible than the previous approach. This DPP is being set within a context of decarbonisation and cost pressures facing both EDBs and consumers. Increasing flexibility in the step change decision-making process will help ensure EDBs have sufficient revenue to run and maintain the network in a way that meets consumers' evolving needs over the long-term.

[101] For example Orion "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 8; and The Lines Company (TLC) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 2. See **Attachment C** for more discussion.

[102] See section *O2.1: Consider proposed step changes against a defined set of factors, applying judgement* in **Attachment C** for more discussion.

O3: Decisions to approve and decline suggested step changes

2.93 Applying the decision-making framework outlined above, we consider that including additional opex for the following changes would better promote consumers' long-term benefit:

2.93.1 Insurance (**decision O3.1**);

2.93.2 Greater consumer engagement (**decision O3.2**);

2.93.3 Low voltage (LV) monitoring and smart meter data (**decision O3.3**);

2.93.4 Cybersecurity (**decision O3.4**);

2.93.5 Software as a Service (**decision O3.5**); and

2.93.6 A graduate programme (**decision O3.14**)**.**

2.94 See **Attachment C** for more information about the rationale for including these step changes and commentary on our analysis and response to submissions.

2.95 Table 2.6 shows step changes which were suggested, and which we declined on the basis that they do not sufficiently satisfy enough factors under the step change decision-making framework outlined above. Unless otherwise stated, decisions here are the same as the draft decisions.

Table 2.6 Reasons for declining suggested step changes

Suggested step change	Rationale for declining
Resilience / storm response	The base spend from DPP3 has captured the response to events in the last five years, and will be increased with the trend factors applied in the base-step-trend approach. In addition, an EDB will be able to apply for a catastrophic event reopener if an extreme weather event meets the reopener criteria.
Decarbonisation related step change from process heat conversion	Insufficient information to provide enough certainty that the cost will occur during DPP4 or will be widely applicable. Spend driven by additional capex partially captured by the addition of a capex driver of non-network opex scale trends (see **decision O5.4**).
Distribution system operation	Underlying uncertainties about the role of the distribution system operator (DSO). Insufficient information to provide enough certainty that the cost will: occur at all, occur during DPP4, and would necessarily all apply to regulated electricity lines services.
Renewal of ageing assets portfolio	Insufficient evidence provided about connection between asset health information and cost impact, and where ageing assets drive increased capex partially captured in the addition of a capex driver of non-network opex scale trends (**decision O5.4**).
Routine and corrective maintenance and inspection	This was submitted by only one EDB, and the evidence provided did not meet the requirements for a step change as the driver for the increase in costs was not outside of the EDBs control.
Operating costs to support the increasing demand on the electricity network driving increases in capex.	Spend driven by additional capex is partially captured by the addition of a capex driver of non-network opex scale trends (**decision O5.4**).
Retendering of Field Service Agreements	Insufficient evidence was submitted that this will not be captured by trend factors and input cost escalators. EDBs also submitted for this to be accounted for as an opex reopener (instead of a step change), after the tender process was completed. We consider that extending the scope of the reopeners to account for the cost increases after the tender process would undermine the regime's ex-ante incentives for EDBs to act efficiently.
Workforce requirements related to network growth. **Powerco resubmitted for an increase in resources for 'customer expectations and technology'. This is different to our draft decision, where the declined step change included the graduate programme.**	Already captured via opex scale drivers (**decisions O5.3 and O5.4**). We consider that the type of work described under 'customer expectations and technology' is captured in base allowances and through the step changes for LV monitoring and the graduate programme. We did not consider the driver behind the step and benefit to consumers were adequately justified.
Workforce related step-changes not linked to system growth – environmental, social, governance reporting functions	This step was not widely applicable, and there was insufficient evidence provided to properly assess all of the factors (specifically, whether the step change was adequately justified and due to a driver outside the control of a prudent and efficient supplier).

2.96 **Decision O3.7** is to apply an aggregate cap of 5% of total opex to the level of increase from approved opex step changes in DPP4, excluding a specified amount for insurance and LV monitoring data step changes.[103]

2.97 Some EDBs submitted for significant cost increases that would lead to increases in their opex allowance of up to 10% above the base and trend components. Our view is that this level of increase would require a level of assessment and scrutiny beyond what is possible for this DPP decision.[104] We consider that a 5% cap represents an appropriate threshold above which, further assessment would be required to determine the costs are prudent and efficient, and that the possible increase to consumer bills would be for their long-term benefit.

2.98 We also consider the 5% threshold is sufficient when compared to the 25% cap for capex, due to the underlying predictability of opex, and the growth to opex allowances already applied through trend factors.

2.99 Separately to the 5% cap we have allowed step changes for insurance and LV monitoring costs for all EDBs. We have calculated the amount for these step changes using the same approach for all EDBs. Where an EDB did not apply, this is the total amount we have allowed them for these step changes. For EDBs that did apply for these step changes, any additional amounts applied for above this value have been included in their opex step changes that are subject to the 5% cap.

Opex Trend Decisions (O4, O5, O6)

2.100 Our forecasting of opex trends has three components: input prices, cost increases with scale, and productivity. We aim to forecast opex trends over the DPP4 period based on estimation of expected changes in these factors and in a way which incentivises efficiency.

[103] The 5% cap and step change amounts are calculated on a constant 2024 dollar basis. Opex profiles on a constant $2024 basis are then expressed in nominal terms using the cost escalators in **decision O4.2**.

[104] Commerce Act 1986, s 53K.

O4. Cost escalation

2.101 Stakeholders have highlighted the impact rising input prices over recent years – and the prospect of future increases over-and-above inflation – as a major concern for this reset. Our recent IM change to calculate efficiency incentives in inflation-adjusted terms (known as a 'real IRIS') substantially reduces the risk to EDBs and to consumers from inflation being over- or under-forecast.[105] This helps better manage uncertainties about future cost rise (as implemented by **decision I2,** see **Attachment D**).

2.102 However, cost escalator forecasts still need to account for forecast changes relative to overall inflation – or 'real price effects'.

2.103 **Decision O4.1** is to escalate all opex costs using the same cost escalator.

2.104 **Decision O4.2** is to forecast opex cost escalation using:

2.104.1 forecasts of the all-industries labour cost (60% weighting) and producers price indices (40% weighting); and

2.104.2 a +0.3% per year additional adjustment, to reflect estimated price impacts that EDBs face over and above these LCI/PPI indexes.[106]

2.105 As discussed in **Attachment C**, we considered alternatives of applying escalation at a more specific cost-category level. This approach aims to capture EDB-specific drivers such as traffic management costs or particular skilled labour constraints. We did not consider we had the necessary data to justify taking this approach in DPP4.

[105] Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023); and Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), topic 5c.

[106] The electricity, gas, waste, and water services labour cost index was used in making this estimate.

Decision O5. Scale trends

2.106 The cost of maintaining and managing a network is expected to increase as it grows. As in DPP3, we approach opex scale trends with an econometric method to model historical opex across EDBs with scale factor variables. The aim of this modelling is to identify which set of scale factors best explains recent opex trends which can then be used to forecast opex growth over DPP4 using trends in these factors. We separate scale trends from input cost trends by modelling historical costs after deflating with observed values of the above cost escalation series (and including the 0.3% per annum adjustment).

2.107 Overall, we have retained the key features of this approach from DPP3, updated for new data and informed by external review[107] and submissions.[108] We discuss this more fully in **Attachment C**, and present modelling results to support our decisions. The key related decisions are summarised below:

2.108 For modelling and forecasting, **decision O5.1** is to retain the split into network and non-network opex. We considered further disaggregation into sub-components but, as at DPP3 reset, we rejected it due to weaker explanatory power of fitted models.

2.109 **Decision O5.2** is to update the reference period for ID data used in scale factor modelling to be regulatory years 2018-2024. Following analysis of longer date ranges, we consider 2018-2024 is suitable because it captures the most recent trends, while also requiring enough data points for reliable modelling. The same number of years was used in the DPP3 reset.

2.110 **Decision O5.3** is to model growth in network opex with the same scale factors as in DPP3, that is ICP count and total lines length for supply. This selection follows review of alternatives, including capex as a cost-driver and the use of a time variable.

2.111 **Decision O5.4** is to model non-network opex growth with ICP count, lines length and capex (expenditure on assets). The change to include a capex term follows consultation on this possibility, motivated by improved model fits, and by submissions supporting the business logic of this relationship.

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[107] We engaged CEPA to report on opex trends before we published the DPP4 Issues paper.

[108] Including trend modelling by Frontier Economics- Frontier "Opex econometric modelling", prepared for Electricity Networks Aotearoa, (9 January 2024) in response to the DPP4 Issues paper, and Firstlight Network "Submission on EDB DPP4 draft decisions" (12 July 2024).

2.112 Submissions on our approach to opex econometric models proposed in the DPP4 Issues paper included the suggestion to include a time variable in both network and non-network opex scale-trend models.[109] Adding a time variable does improve model fit on historic data but does so without attributing the effect to a driver that can be forecast. We consider an approach where scale trends are linked to known factors, and any time effects are captured by forecasts in cost escalators (where they relate to input costs) or forecast change in productivity (where they cannot be explained by input or output trend) is a more transparent approach. In addition, step change allowances would be correlated with some of the time-based movements, especially insurance, which ID data show to have increased at above the rate of input price inflation.

2.113 Submissions on our draft decision included suggestions to reconsider aspects of our econometric modelling. Proposed changes to our 'predictor variables' and our modelling approach did not improve model performance and we have retained the model structure and scale trend variables from our draft decision.[110, 111, 112]

2.114 Our final elasticities are from our updated econometric modelling. Key elements of our modelling approach are:

2.114.1 the reference period of ID data was extended to 2018-2024 (from 2018-2023 in the draft);

2.114.2 the DPP3 approach to data quality was retained;[113] and

2.114.3 the cost escalators used in our data preparation include the additional adjustments +0.3% annually for opex and +0.8% annually for capex, in line with their use elsewhere in our final decisions.

2.115 The elasticities are shown in Table 2.7.

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[109] Frontier Economics “Opex econometric modelling” - (prepared for Electricity Networks Aotearoa, 9 January 2024).

[110] Firstlight Network “Submission on EDB DPP4 draft decisions” (12 July 2024).

[111] Alpine Energy “Submission on EDB DPP4 draft decisions” (12 July 2024).

[112] Unison Networks "Cross-submission on EDB DPP4 draft decisions" (2 August 2024).

[113] As in DPP3, we have applied an iterative model outlier exclusion process when fitting the econometric models used to calculate elasticity values. We have not applied an additional step, introduced in our DPP4 draft decision, to filter out irregular input data. See **Attachment C** for discussion.

Table 2.7 Elasticities for network and non-network opex

Opex category	Elasticity to ICP growth	Elasticity to lines length growth	Elasticity to capex
Network opex (decision O5.3)	0.44	0.53	-
Non-network opex (decision O5.4)	0.20	0.35	0.31

2.116 Opex trend rates are found by multiplying these elasticities by forecast growth rates in the associated scale factors over the DPP4 period. We have forecast growth rates in ICP count and lines length by extrapolating recent trends. This is the same approach for lines length as in DPP3. For ICP counts, this replaces the use of Statistics NZ Household Growth (HHG) forecasts for ICP growth in DPP3. We found HHG forecasts generally under forecast recent ICP growth in large urban areas, with over forecasting in smaller rural areas.

Decision O6. Opex Partial Productivity

2.117 **Decision O6.1** is to apply an opex partial productivity factor (PPF) of 0%. This decision draws on recent trends in price-quality-regulated EDB measured productivity and consideration of both the prospect of opex-capex substitution (suggesting a lower PPF) and the possibility of innovations and new approaches improving operating productivity (suggesting a higher PPF).

2.118 As set out in **Attachment C** this decision has been informed by findings from CEPA's productivity study and submissions on their draft report.[114,115]

[114] CEPA "(FINAL) EDB Productivity report: A report prepared for the Commerce Commission" (24 June 2024).

[115] Submissions on CEPA's Draft report are published on the Commission's website.

Chapter 3 Incentivising performance improvement during the energy transition

Purpose of this chapter

3.1 This chapter:

3.1.1 explains the challenge of incentivising performance and improvement during the energy transition;

3.1.2 identifies, and explains the rationale for, each of our final decisions which relate to:

3.1.2.1 incentives for innovation, energy efficiency, demand-side management, and the reduction of energy line losses;

3.1.2.2 quality standards and incentives, normalisation and reference period; and

3.1.3 directs readers to further information about the development of the draft decisions for innovation and quality (see **Attachments D** and **E**).

The challenge of incentivising performance and improvement during the energy transition

Incentives

3.2 DPP/CPP regulation provides baseline incentives for EDBs to innovate and achieve efficiencies that maintain and improve their performance in supplying electricity lines services (see paragraph 3.9). These incentives could also play a significant role in the energy transition. Shaping these incentives for DPP4 is challenging when considered in the context of the increasing demand for electrification, climate change impacts on weather patterns, significant cost pressures on EDBs and consumers, and uncertainty around the need and timing for some significant capital investments.

Innovation incentives

3.3 EDBs have incentives to innovate and implement non-traditional solutions where these are lower cost than traditional solutions; for example, if the solution allows the EDB to defer or avoid capital investments they can retain a share of the savings that are made. Innovative approaches to capacity constraints are likely to include a range of potential non-traditional (or non-network) solutions. Some non-traditional solutions are already well-proven in Aotearoa New Zealand, such as diesel generation sets, and to a lesser extent batteries. If tested, trialled, and optimised, we expect that proven solutions could significantly benefit consumers, and, over time, could become business as usual for EDBs.

3.4 We consider that during DPP3, incentives for EDBs to try non-traditional solutions that are less proven may in some instances not have been strong enough. We acknowledge that trying less proven ways of doing things can place temporary risks on financial and/or quality performance in some instances. Our final decision addresses this challenge by introducing an INTSA (**decision U1**) and a quality standards exclusion for INTSA projects (**decision RP7**), among other measures.

Quality

3.5 We are required by the Part 4 of the Commerce Act to set quality standards that must be met by regulated suppliers when setting price-quality paths.[116] We may also set incentives for an EDB to maintain or improve its quality of supply.[117]

3.6 These quality standards and incentives are a crucial part of promoting the purpose of Part 4 of the Act; they are important for ensuring EDBs have incentives to provide services at a quality that reflects consumer demands. As EDBs' revenues are constrained by the price path, quality standards are important for ensuring EDBs have incentives to invest and are constrained in their ability to earn excessive profits at the expense of quality.

3.7 No material deterioration in reliability is the starting point for our approach to quality at every DPP reset, as assessed using the quality standards. We also acknowledge the need for EDBs to make trade-offs about the level of quality they deliver, and the cost they incur in doing so, as reflected in the quality incentive scheme. It is important for EDBs to consider price-quality trade-offs at the margins, and to have the ability to move towards a level of quality that better reflects consumers' demands and the EDB's cost to serve those consumers.

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[116] Commerce Act 1986, s 53M(1)(b).
[117] Commerce Act 1986, s 53M(2).

3.8 In submissions on our draft decision, there was general support to keep the principle of no material deterioration and to broadly maintain the quality settings determined in DPP3.

Decisions for innovation incentives

3.9 When setting the DPP, we must make decisions about how to promote outcomes such that suppliers of regulated lines services have incentives to innovate.[118] We must also consider how we promote incentives (and not impose disincentives) for EDBs to invest in energy efficiency and demand-side management measures, and to reduce energy losses.[119]

3.10 The DPP includes incentives for EDBs to invest in innovative and non-traditional solutions, by having:

3.10.1 flexibility to spend their capex and opex allowances as they see fit;

3.10.2 a revenue cap with an IRIS that incentivises EDBs to seek the most efficient solution; and

3.10.3 a quality incentive scheme.

3.11 **Decision I1** sets the capex IRIS incentive rate at 32.16% for DPP4, to match the incentive rate that will apply to opex and continue the approach applied in DPP3.[120] Equalising EDBs' financial incentives between opex and capex solutions ensures that they are incentivised to choose the best solution, regardless of expenditure category. We expect opportunities for such substitutions to increase over DPP4. This decision is explained in **Attachment D**.

3.12 We recognise that in some instances, non-exempt EDBs may still lack strong enough incentives for projects that have higher risk, and/or where financial benefits are unlikely to be received by the EDB.

[118] Commerce Act 1986, s 52A(1)(a); and Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023).

[119] Commerce Act 1986, s 54Q.

[120] This is an increase from DPP3 where the incentive rate was 23.5% and is driven by an increase in the opex retention rate, which is a function of the WACC and retention period. This means that approximately 68% of any overspend incurred by an EDB and approximately 68% of any underspend would be shared with consumers.

3.13 To address these potential gaps in incentives, the 2023 Input Methodologies (IM) Review provided for an Innovation and Non-traditional Solutions Allowance (INTSA) through the DPP (and any CPPs) from DPP4.[121] At a high level, **decision U1** for the INTSA, provides EDBs with further incentives to deliver innovative projects or non-traditional solutions.

3.14 EDBs have shared their ambitions to invest in innovation and non-traditional solutions, in particular to test and roll-out flexibility services and/or use DER, to better meet peak demands on their network.[122] **Decision U1** to introduce INTSA provides an additional incentive for EDBs to find alternative, more efficient ways to run and adapt their networks to decarbonisation trends, resilience expectations and changing consumer preferences.

3.15 Our intention is that the INTSA scheme, as introduced through our final decision and in line with the policy criteria described in Table 3.1, encourages EDBs to deliver long-term benefit to consumers through innovation projects and non-traditional solutions:

3.15.1 where the benefits of the project are sufficiently uncertain such that the project would not otherwise occur if the EDB could not recover some or all of the forecast costs of the project from the EDB's INTSA allowance. This may be because some innovation projects and non-traditional solutions involve higher risk than business as usual solutions; or

3.15.2 where the project is unlikely to otherwise result in any financial benefits for the EDB in the five disclosure years after it expects its project will be completed. This might be because there are no explicit financial incentives for EDBs if the benefits accrue entirely to third parties or are not realised because of a change in regulatory period.

[121] Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023: Final decision" (13 December 2023), see **Decision SP05**, para. 7.31.4.

[122] EDBs have shared these ambitions in conversations with the Commission in 2023 and 2024, and by contributing to the development of the Electricity Networks Aotearoa (ENA), "Powering up for change: New Zealand Electricity Distributor Network Transformation Roadmap: A three-year update" (April 2022).

3.16 There has been a high level of interest in innovation and the INTSA throughout the DPP4 reset, and this has been reflected in submissions and in engagement at the two targeted INTSA workshops. Stakeholders have focussed on areas such as support for flexibility services and energy efficiency initiatives, as well as engaging well with the specific characteristics of our draft INTSA design. Additionally, at the draft decision, we received suggestions for improvements to the INTSA such as amending the eligibility criteria and introducing an ability to change projects post-approval (where beneficial for consumers).

3.17 The final INTSA design reflects changes from what we proposed in the draft decision as we have taken this feedback into account where we judged it was in the long-term benefit of consumers. The key changes are:

3.17.1 an increase in the INTSA maximum allowance from 0.6% to 0.8% of each EDB's DPP4 MAR, with 0.2% ring-fenced for projects that involve the EDB working together with one or more other EDBs;

3.17.2 a change in language for the third project eligibility criterion to reflect feedback that the previous 'business as usual' criteria would be difficult to demonstrate in practice.

3.18 All changes made to the INSTA are discussed in detail in **Attachment D** and the final policy design of the INSTA is set out in the table below. **Attachment D** also explains the rationale for each of the nine INTSA characteristics and includes a table that sets out each EDB's maximum INTSA allowance.

Table 3.1 DPP4 INTSA policy characteristics

Criteria type	INTSA policy criteria
Project type – what the project is for	An innovative or non-traditional solutions project that fits within the three eligibility criteria: 1. relates to the supply of electricity lines services; 2. promotes the Part 4 purpose of the Act; and 3. one or both of the following applies: (i) the project is unlikely to otherwise result in any financial benefits to the EDB in the five disclosure years after the date by which it indicates that it expects it will complete its project; (ii) the benefits of the project are sufficiently uncertain that the EDB would not carry out the project if it could not recover some or all of the forecast costs of the project from its INTSA.
Approval timing	Ex ante
Expenditure approved	Forecast
Share of expenditure approved (%)	Up to 100% for a project that meets the criterion of being unlikely to otherwise result in any financial benefits to the EDB in the five disclosure years after the date by which it indicates that it expects it will complete its project. Up to 75% for a project that does not meet the criterion referred to immediately above.
When and on what conditions approved expenditure is received	Expenditure may be recovered upon project completion - when all the INTSA project outputs have been delivered.
Maximum allowance	0.8% of each EDB's DPP4 maximum allowable revenue (MAR) over the regulatory period for one or more projects, of which 0.2% of DPP4 MAR can only be used for projects that involve the EDB working together with one or more other EDBs.
Supporting evidence	Project specific information.
Sharing learning	Close out report must be sent to the Commission within 50 days of project completion, unless otherwise approved.
Penalty/reward mechanism	None [123]

[123] This is with respect to an explicit penalty/reward mechanism specified as a part of the INTSA. Expenditure incurred undertaking an eligible INTSA project would still be subject to IRIS. See Commerce Commission "Input Methodologies Review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), topic 5e.

3.19 To help share the knowledge gained from both successful and less successful projects, a requirement of the INTSA will be for EDBs to share their learnings publicly via a close out report. We expect stakeholders to then be able to draw insights from completed innovative and non-traditional solutions projects, and this growing body of shared learnings. This may also inform the innovation incentive mechanisms used in future DPP resets.

3.20 **Decision RP7** introduces a limited exclusion from quality standards for INTSA projects. This is designed to reduce the risk that EDBs are discouraged from trialling non-traditional solutions by allowing EDBs to exclude interruptions directly associated with INTSA approved projects, subject to an aggregate cap for all such projects. See the section on *decision RP7* in **Attachmen**t **E**.

3.21 The INTSA is also designed to meet the requirements of s 54Q of the Act, under which the Commission must promote incentives, and avoid imposing disincentives for electricity lines suppliers to invest in:

3.21.1 energy efficiency (**decision U2**);

3.21.2 demand-side management (**decision U2**); and

3.21.3 reduction in energy losses (**decision U3**).

3.22 See **Attachment D** for further information on how the INTSA supplements existing regime incentives in these areas.

3.23 We also considered a range of alternative options for the INTSA policy design. These included a more ambitious, outcomes-based option that would have allowed EDBs a significantly larger allowance (e.g. up to 5% of MAR) but with greater consumer protections in order to reallocate risk from consumers to suppliers.[124]

3.24 However, in our assessment, the final INTSA design sufficiently promotes the Part 4 purpose and is likely to be more appropriate for a relatively low cost DPP than the ambitious outcomes-based option. Further, given that the final INTSA is a significant change from the Innovation Project Allowance from DPP3, it would be appropriate to first assess its impact at DPP4 and then consider further reform. Finally, we consider that more complex or costly INTSA schemes could be provided for in a CPP, if justified.

[124] See *Highly ambitious option*, **Attachment D**.

Decisions for quality standards and quality incentives

3.25 Significant revisions to the quality standards and quality incentive scheme (QIS) were made for DPP3, compared to DPP2. We consider the DPP3 quality standard settings, normalisation approach for major events and QIS settings are largely fit for purpose. Submitters on our draft decision also broadly supported this approach although some targeted adjustments were requested.

3.26 Our final decisions contain minor changes to better reflect the operating environment in DPP4. These include both minor changes to approach and changes related to using more recent data.

3.27 Decisions related to quality are outlined against four themes:

3.27.1 the quality standards that EDBs must meet (**decisions QS1 – QS11**);

3.27.2 the quality incentives which apply to EDBs (**decisions QIS1 – QIS10**);

3.27.3 reliability normalisation, which reflects how major events are accounted for within the standards and incentives (**decisions N1 – N5**); and

3.27.4 the reference period that applies for establishing planned and unplanned interruption settings (**decisions RP1- RP7**).

Final decisions for quality standards

3.28 Our final decision for DPP4 is to retain the three quality standards, focussed on the reliability of supply. They are:

3.28.1 SAIDI and SAIFI limits for unplanned interruptions, assessed on an annual basis;

3.28.2 SAIDI and SAIFI limits for planned interruptions assessed across the full regulatory period; and

3.28.3 an extreme event standard for high impact and low probability events, assessed as more within the EDB's control.

3.29 Table 3.2 presents the final decisions for quality standards.

Table 3.2 Quality standards for DPP4

EDB	Unplanned SAIDI (1-year)	Unplanned SAIFI (1-year)	Planned SAIDI (5-year)	Planned SAIFI (5-year)	Extreme outage (per event)[125, 126]
Alpine Energy	118.47	1.1372	825.77	3.1437	120 SAIDI
Aurora Energy[127]	128.36	1.9675	1,077.78	6.0924	6m CIM
EA Networks	87.38	1.2416	1,238.47	4.4045	120 SAIDI
Electricity Invercargill	27.15	0.6608	125.94	0.5702	120 SAIDI
Firstlight Network	230.43	3.3101	1,213.15	6.7271	120 SAIDI
Horizon Energy	184.80	2.2709	944.50	5.9856	120 SAIDI
Nelson Electricity	18.62	0.4063	162.10	2.1297	120 SAIDI
Network Tasman	98.33	1.1358	1,067.94	4.4119	120 SAIDI
Orion NZ	80.47	0.9819	218.24	0.7399	6m CIM
OtagoNet	168.37	2.3401	2,323.77	9.2088	120 SAIDI
Powerco	189.27	2.1550	849.75	3.8125	6m CIM
The Lines Company	190.55	3.2839	1,284.15	7.8774	120 SAIDI
Top Energy	399.25	4.8196	1,727.59	8.5279	120 SAIDI
Unison Networks	81.52	1.7244	688.37	4.9114	6m CIM
Vector Lines	110.07	1.4034	643.92	3.1661	6m CIM
Wellington Electricity	37.82	0.5829	76.66	0.6089	6m CIM

[125] The extreme event standard is specified in SAIDI minute and CIM terms. CIM means customer interruption minutes, which is the sum of the total duration in minutes accumulated for each ICP for each interruption, with “m” representing millions.

[126] These values are indicative only. We have determined these values based on the EDB's number of ICPs at 31 March 2024. However, the extreme event provision operates on whether either threshold is exceeded during the period so may change if the EDB's number of ICPs change.

[127] Aurora is currently on a CPP which ends on 31 March 2026. Under clauses 9.5 and 9.6 of the DPP determination, where an EDB transitions from a CPP to a DPP during the regulatory period, the planned SAIDI and SAIFI limits are adjusted in the assessment of compliance. For Aurora, this means that for assessment purposes, it will divide the SAIDI and SAIFI limits determined by five years (regulatory period), then multiply by four years (assessment periods on the DPP) to calculate the value of the planned SAIDI and SAIFI limits that apply.

3.30 Submitters generally supported the continuation of the existing measures for quality standards, although there were some concerns, particularly with the setting of planned standards, which we address under the relevant decisions below. Responses to our draft decision broadly supported not introducing new quality standards in DPP4, with a number noting that further development of information may help inform standards for future price-quality paths.

3.31 **Decision QS1** is to maintain a separate standard for planned outages, rather than combined with unplanned. This avoids a potential perverse incentive for EDBs to defer network investment or maintenance needed to prevent unplanned outages. If these were combined, where an EDB is incurring higher unplanned outages than anticipated the EDB may defer planned investment that helps maintain reliability but creates an interruption, to stay within its overall cap in the short term.

3.32 **Decision QS2** is to maintain the unplanned interruptions standard assessed on an annual basis for SAIDI and SAIFI. We consider an unplanned standard, assessed annually, can be set in a way that reduces the risk of false positives and allows for more timely compliance investigations.

3.33 **Decision QS3** is to retain the 2.0 standard deviation buffer for setting the unplanned interruptions reliability standards limit.[128] In the absence of a buffer compared to the historical average (2015-2024), the quality standards we set for unplanned interruptions would be vulnerable to random volatility.

3.34 **Decision QS4** is to retain the planned SAIDI and SAIFI interruptions standard assessed over the length of the regulatory period. There are long-term benefits to consumers stemming from the network investment and maintenance that is associated with planned interruptions. Applying the planned interruptions quality standard over the full regulatory period allows EDBs to schedule planned work in a way that works best for their business and consumers.

3.35 **Decision QS5** is to set the buffer for the planned interruptions reliability standard to be a 100% uplift on the historical average (2018-2024), capped at a +/- 10% movement from the current limit.

3.36 Setting a buffer above the historical average recognises that there are long-term benefits to consumers from the network investment and maintenance that is associated with planned interruptions and allows for some flexibility in work practices.

[128] 'Buffer' refers to the uplift applied between the ‘target’ which represents historic performance and the ‘limit’.

3.37 Submitters on the draft decision generally considered that the 100% uplift on the historical average (reduced from 200% in DPP3) and the introduced 10% cap should both be higher.

3.38 We shortened the reference period used to set the standard for planned interruptions from ten years in DPP3 to seven years (2018-2024) for this reset, combined with rolling forward the reference dataset to reflect recent years. This new reference period more accurately reflects current network practices (see **decision RP2** below). This has significantly increased the annual average planned SAIDI and SAIFI for most EDBs. Our analysis also broadly indicates that DPP3 and DPP4 limits both provide significant buffer compared to current levels of planned interruptions, so there is limited justification for further uplift to the draft standard.[129] Introducing a cap limits the scope of change between regulatory periods and acts to protect consumers from material deterioration, while some variability is accepted as normal. As such, we have retained our draft decision to reduce the buffer compared to DPP3 and introduce a +/-10% cap to limit movement across regulatory periods.

3.39 **Decision QS6** is to retain the de-weighting of notified planned interruptions by 50% in the assessment of compliance with the SAIDI planned interruption standard. This is due to the reduced impact of notified interruptions on consumers.

3.40 **Decision QS7** is to retain SAIDI extreme event standard set at the lower of either 120 SAIDI minutes or 6,000,000 customer interruption minutes. The 'extreme event standard' deals with extreme one-off events. In the absence of a standard relating to extreme events, the unplanned reliability standards (with normalisation) may miss large interruption events that are caused by not applying good electricity industry practice or under-spending on network maintenance and investment.

3.41 **Decision QS8** is to retain enhanced automatic reporting following a breach of a quality standard. Such disclosures help to improve our ability to assess compliance with the price-quality path, and to reduce the cost and uncertainty involved when an EDB contravenes its quality standards. Such disclosures also provide greater transparency and accountability of EDBs for their quality performance.

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[129] See **Attachment E**, *decision* **QS5**.

3.42 **Decision QS9** is that no new quality measures be introduced as part of the quality standards applying in DPP4. While there is merit in considering a wider range of measures of quality of service, we consider that quality standards should align with what consumers value, be measurable, and have clarity on what an appropriate target would be such that EDBs can be influenced towards outcomes that represent value for consumers. Some aspects of network performance may be better addressed through our programme of information disclosure and performance analysis.

3.43 **Decision QS10** is to set quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP. We do not consider that Aurora is such an outlier that it requires a different application of the quality standard and incentives from other EDBs to maintain consistency with our principle of no material deterioration. The change to Aurora's targets and limits will be capped relative to its current CPP quality targets and limits.

3.44 **Decision QS11** is to retain the requirement for reasonable reallocation of quality parameters following a transfer of more than 0.5% of ICPs of the smallest non-exempt EDB that is party to the transaction. Consumers should not bear the risk of being worse-off due to an asset transfer transaction, in terms of quality of service. However, we agree with submissions on our draft decision that a minimum threshold is appropriate to prevent unnecessary compliance costs for transfers that have minimal impact.

Final decisions for quality incentive scheme

3.45 For DPP4, our decision is to retain the QIS which currently applies under DPP3. The QIS defines the range within which EDBs can make marginal trade-offs between the quality and price of the services they provide. It creates a relationship between changes in network reliability, increased or lower revenue allowances and consumers' cost-quality preferences. The QIS is linked to the value of lost load (VoLL), [130] to approximate the value consumers place on reliability, and a sharing factor that matches the IRIS retention factor, so benefits are shared between consumers and EDBs.

3.46 In submissions on our draft decision, there was general support for the continuation of the existing QIS. This included support for our approach to inflating VoLL and continuing to de-weight notified planned interruptions.

[130] Schedule 12.2 clause 4 of New Zealand's Electricity Industry Code 2010 (the Code) includes a value of VoLL (called 'Value of expected unserved energy') as $20,000 per MWh. This number dates from December 2004. We have inflated this figure to $35,305 / MWh for DPP4. See *Accounting for inflation in calculating VoLL* in **Attachment E**.

3.47 **Decision QIS1** is to retain the revenue-linked quality incentive scheme for planned and unplanned SAIDI; SAIFI is excluded. Applying the QIS to both SAIDI and SAIFI risks double-counting the SAIFI impact because SAIDI is a function of interruption frequency (SAIFI) and interruption length (CAIDI).[131] SAIFI will still be subject to compliance standards and SAIFI, as well as CAIDI, are indirectly captured through SAIDI incentives.

3.48 **Decision QIS2** is that unplanned incentive rates are informed by the VoLL, discounted by (one minus the IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VoLL set at $35,305/MWh. We have increased the VoLL to reflect recent inflation to more accurately represent the current value for consumers. We have factored in the expenditure incentive because EDBs only bear a proportion of additional expenditure associated with quality improvements, as determined by the IRIS mechanisms. The further 10% reduction reflects the incentive associated with not contravening the quality standard.

3.49 **Decision QIS3** is that planned interruption incentive rates are reduced by 50% relative to the unplanned interruption incentive rate. We have changed the de-weighting of planned incentive rate from our draft decision, reverting to the rate which applied at DPP3 to address submissions on the misalignment between the de-weighting of notified interruptions in assessment of the quality standard and the QIS. The de-weighting is reflective of planned interruptions generally having lower consumer impacts than an unplanned interruption, even where the EDB does not meet the criteria for notifications associated with the 'notified' interruptions category.

3.50 **Decision QIS4** is that 'notified' interruptions are reduced by 75% relative to unplanned in calculating the incentive, to reflect less inconvenience to consumers where they receive advance notification. We have maintained the strength of the notified interruption incentive given consumers' preference for greater notification of interruptions.

3.51 **Decision QIS5** is that the incentives are broadly revenue-neutral at the average of the reference period, also known as the target. The quality target is the level of reliability performance at which the revenue impact of an EDB's performance is zero, ie, it is the point at which losses turn into gains and vice versa.

[131] Customer Average Interruption Duration Index (CAIDI) is the average time required to restore service. It is calculated as total minutes of customer interruption divided by the total number of interruptions.

3.52 Submissions on the draft decision considered that the planned target should be lifted above the historical average to align with the expectation that increased investment will increase interruptions.

3.53 Reducing the planned reference period from ten years to seven years reflects the more recent step change in planned interruptions and has raised the historical average (see **decision RP2** below). In addition, notified interruptions are not de-weighted in the reference period dataset which results in the historical average being set higher than if this were to be taken into account, as it is within the assessment period. We consider this uplift is likely to more than offset the effect of any increases to work programmes. Our final decision is therefore to retain setting the target based on the historical average.

3.54 **Decision QIS6** is for the SAIDI caps (which determine maximum losses) to be set equal to the SAIDI limits for planned and unplanned SAIDI. We consider that it is appropriate for EDBs to consider trade-offs all the way up to the limit, as this preserves the marginal incentive to improve reliability (or avoid further declines) regardless of their performance up to that point in the assessment period.

3.55 **Decision QIS7** is to set the SAIDI collars (which determine maximum gains) at zero for planned and unplanned SAIDI, subject to a specified maximum revenue exposure. This means that financial incentives to improve reliability will always apply between zero and the SAIDI limits.

3.56 **Decision QIS8** is to cap revenue at risk to 2% of actual net allowable revenue. Revenue at risk is the total pool of incentives an EDB may gain or lose based on its performance. We consider the 2% cap means the SAIDI incentive rate applies for an appropriate range of performance and ensures variations in quality performance, which can be driven by external factors, does not create an excessive level of revenue exposure.

3.57 **Decision QIS9** is not to implement any new incentives as there is not a clear new incentive which has a robust dataset and would provide appropriate incentives for a particular type of performance which consumers value.

3.58 **Decision QIS10** is not to make an adjustment to match the duration of retention benefits between EDBs and consumers for the QIS. We adjust the quality incentive rate for the impact of the IRIS schemes, which reduces the cost to an EDB of improving quality. However, we do not make a similar adjustment to account for the fact that EDBs only keep the quality incentive payments associated with reliability improvements until they are reflected in the reference data used to set the quality targets. We are not convinced that strengthening EDBs incentives to invest in reducing SAIDI impact will move us closer to the social optimum for reliability.

Final decisions for normalisation

3.59 The process of normalisation is intended to prevent the effects of severe storms being mistaken for signs of network deterioration.

3.60 There was general support from submitters on the draft decision to retain the existing approach to normalisation. We considered points raised on the potential for increased incidences and the prolonged effect of major events. Normalisation may not address all the unusual effects of large events. We consider the specific context of any breaches when exercising enforcement discretion. We consider that our normalisation approach and the related expectation of major events remains appropriate, so we have retained our draft decisions on normalisation.

3.61 **Decision N1** is that normalisation only applies to unplanned interruptions, which are the only initiators of a major event.

3.62 **Decision N2** is to retain the normalisation approach used in DPP3, being:

3.62.1 define a major event as any period of 24 hours (assessed in 30-minute blocks) where the sum of SAIDI or SAIFI values exceeds the unplanned boundary value;

3.62.2 retain from DPP3 a statistical expectation of 2.3 major event days (MED) per year and setting the boundary value for major events as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period (apart from two EDBs under decision N4);[132]

3.62.3 normalisation is applied on half-hour blocks, within a major event, where the SAIDI or SAIFI figure exceeds 1/48th of the boundary value; and

3.62.4 for major events, replace any half-hour that is greater than 1/48th of the boundary value with 1/48th of the boundary value if that half-hour is part of the major event (can exceed 24 hours in duration).

3.63 We consider that maintaining the replacement of identified time periods within major events with a reduced replacement value is appropriate, given that:

3.63.1 enhanced major event reporting requirements can provide more transparency and incentives around the main cause of events;

[132] To set the 1104th highest boundary value, we started with a statistical expectation of 2.3 major event days (MED) per year x 48 (half hours per day) to reflect a rolling half-hourly assessment x 10-year length of the regulatory period, ie, 2.3 x 48 x10 = 1104.

3.63.2 reducing a large source of volatility may provide a clearer indication of the underlying reliability of the network;

3.63.3 the extreme event standard places further onus on EDBs to take practicable steps to minimise the likelihood of high impact, low probability events that are within their control as well as mitigating the extent of them; and

3.63.4 there are other incentives which minimise risk to consumers of sustained outages, such as customer complaints and reputational risk.

3.64 **Decision N3** is that SAIDI and SAIFI major events are triggered independently, consistent with DPP3. Major events may affect a large number of consumers in an urban area for a relatively short period of time therefore triggering SAIFI but not SAIDI. Alternatively, a relatively small number of consumers may be affected for a significant length of time therefore triggering SAIDI but not SAIFI, eg, a severe storm in a less populous area.

3.65 **Decision N4** is to use a higher ranked rolling 24-hour period to identify the boundary value for small EDBs. We identify these small EDBs as those with networks of less than 1,000 km in circuit length and make a proportional adjustment to identify the appropriate 24-hour period.[133]

3.66 Smaller networks, all else being equal, can expect to have fewer interruptions relative to larger networks. This is because there is less equipment that can fail at any given time and consequently less equipment at risk of truly experiencing a major event. Applying the same 1104th highest value for establishing the boundary value for small EDBs may result in a boundary value which is inappropriately low.

3.67 **Decision N5** is to retain additional reporting by EDBs for each unplanned major event in its compliance statement. We consider that when a major event is identified, there should be transparency as to when and why the major event happened, and the impact of normalising the major event. This is important given our normalisation approach is to replace major events with a pro-rated boundary value, rather than the full boundary value.

[133] Commerce Commission, "Electricity Distribution Information Disclosure (Targeted Review 2024) [2024] NZCC 2" (29 February 2024), Schedule 16 says "circuit length means all lines and cables with the exception of services, street lighting, and private lines (and, when a pole or tower carries multiple circuits, the length of each of the circuits is to be calculated individually)".

Final decisions for reference period

3.68 We base the reliability standards and incentives for planned and unplanned interruptions on an EDB's historical performance, consistent with the principle of no material deterioration. Submitters generally supported our approach with particularly focused engagement on decisions to shorten the planned reference period, exclude interruptions for INTSA projects and identification of step changes from the reference period.

3.69 **Decision RP1** is to use a 10-year reference period of 2015-2024 to inform the parameters for unplanned reliability standards and incentives. The use of a historical reference period as a baseline aligns with the principle of 'no material deterioration' and better reflects the underlying characteristics of the network.

3.70 We consider that setting the reference period using the latest ten years for unplanned interruptions is appropriate, as the period:

3.70.1 is long enough to account for longer term weather cycles;

3.70.2 is long enough to mitigate year-on-year variation due to circumstances outside the EDBs' control;

3.70.3 is long enough to reflect the operating environment of EDBs and even out changes; and

3.70.4 best reflects the current underlying level of reliability performance, given the availability of reliable and consistent data.

3.71 **Decision RP2** is to use a 7-year reference period of 2018-2024, reduced from the 8-year reference period in the draft decision, to inform the parameters for planned reliability standards and incentives.

3.72 Unlike unplanned interruptions, we have seen a significant step change in the level of planned interruptions across nearly all non-exempt EDBs in the historical reference period. After considering submissions on the draft decision, we have decided a shortening from the 10-year reference period used in DPP3 is appropriate to reflect current network practices more accurately.

3.73 **Decision RP3** is to cap inter-period movement, +/-5% for the SAIDI and SAIFI unplanned targets, and the SAIDI and SAIFI unplanned limits.[134]

[134] We calculate a notional SAIFI unplanned target in the same way we calculate the SAIDI unplanned target. However, "SAIFI target" is not defined in the determination as SAIFI is not included in the QIS.

3.74 Aside from acceptable movements within the cap-collar range where EDBs already receive rewards and penalties, we do not consider it appropriate that deteriorating performance should be rewarded with more relaxed standards and improved performance penalised through stricter standards.

3.75 **Decision RP4** is to not make explicit step changes to reliability targets or limits. We have considered certain factors that could be considered to reflect a step change to reliability parameters for quality standards and incentives as compared to the reference period. Our final decision is not to make any step changes, including due to climate change, changes in operational procedures (other than as reflected in the shortening of the planned interruption reference period), bush fire risk and emergency services prohibiting access to outage sites.

3.76 **Decision RP5** is not to make explicit adjustments for instances of non-compliance contained within the unplanned interruption reference period dataset. We note there are instances of non-compliance contained within the unplanned interruption reference period dataset. We consider the 5% cap which applies to both the unplanned reliability targets and limits, appropriately limits the risk that deteriorating performance is rewarded with relaxed standards, consistent with the 'no material deterioration' principle.

3.77 **Decision RP6** is that EDBs must record successive interruptions on the same basis they employed in providing the dataset for the period 1 April 2022 to 31 March 2023 in responding to the s 53ZD notice dated 3 July 2024.[135] In establishing quality standards for DPP3 we identified that EDBs were applying different recording practices for successive interruptions. This approach ensures EDBs continue to apply the same approach used for recording interruptions within the reference dataset. This ensures consistency of performance measurement against the targets and limits over time.

3.78 **Decision RP7** is to exclude interruptions directly attributable to INTSA approved projects or programmes from assessed SAIDI and SAIFI subject to an aggregate 1% cap of the respective SAIDI and SAIFI limits for the quality standards and QIS. We consider that excluding certain interruptions from the quality standards and QIS to account for non-performance of innovative solutions may address concerns that the regime may discourage some types of innovative projects.

[135] A successive interruption means an interruption that follows an initial interruption that either relates directly to that initial interruption, or occurs as part of the process of restoring supply of electricity lines services following that initial interruption.

3.79 Submitters on the draft decision supported excluding such interruptions but some considered a 0.5% cap was insufficient or should be removed. We do not consider that full removal of SAIDI and SAIFI associated with INTSA projects would be appropriate as it would remove the incentive to appropriately manage outage risk associated with these projects. However, we have increased the cap in our final decision.

Chapter 4 Managing price shock risks and the ability for EDBs to finance investments

Purpose of this chapter

4.1 This chapter:

4.1.1 explains the challenge of managing price shock risks and the ability for EDBs to finance investments;

4.1.2 identifies and explains the rationale for final decisions that relate to:

4.1.2.1 setting net allowable revenues on a building blocks basis and smoothing revenues over the regulatory period to manage price shocks;

4.1.2.2 matters that related to the revenue path and wash-up mechanism during the regulatory period; and

4.1.2.3 other inputs to our building blocks financial model; and

4.1.3 directs readers to further information about:

4.1.3.1 consumer price impacts on the Commerce Commission website;[136] and

4.1.3.2 the development of the final decisions for net allowable revenue, the revenue path and financeability (see **Attachments F** and **G**).

4.2 For background information on how we set revenue allowances using a building blocks model and how we smooth revenue allowances over the regulatory period, see the introductory material in **Attachment B** of our DPP4 Issues Paper.[137]

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[136] Commerce Commission webpage "Understanding how changes to line charges may impact your electricity bill".

[137] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues Paper" (2 November 2023), **Attachment B**.

The challenge of managing price shocks and the ability for EDBs to finance investments

4.3 Investment in distribution networks is financed upfront by EDBs, then repaid by their consumers over time as they benefit from the network. Each DPP reset must manage the tension between consumers' interests in:

4.3.1 having access to a network that can deliver the energy services they need at the quality they expect; and

4.3.2 avoiding paying more than is necessary to maintain and expand the network.

4.4 This includes seeking to minimise price shocks to consumers on the one hand while avoiding undue financial hardship to EDBs on the other.

4.5 This tension is especially acute for DPP4 due to factors impacting EDBs and consumers. Rather than either a price shock challenge or a financeability challenge, both are occurring simultaneously.

4.6 To enable EDBs to invest in their networks and earn a normal return on their investment, we set their revenue allowance on a 'building blocks' basis so that forecast revenues equal forecast costs (including the cost of capital).

4.7 Inflation has been higher than forecast over the DPP3 period. Between 2019 (the base year for DPP3) and 2025 (the end of DPP3), cumulative CPI will have been 27%, more than double the forecast figure used when setting DPP3 (12%). This inflation has led to:

4.7.1 an increase in EDBs' operating costs;

4.7.2 higher historical capex; and

4.7.3 higher regulatory asset base (RAB) growth via revaluations.

4.8 Additionally, higher interest rates mean EDBs will face a higher cost of capital for financing their investments.

4.9 The impacts of these factors on EDBs' allowable revenue are set out in Figure 4.1. At an industry-wide level for the final decision:

4.9.1 changes in DPP3 CPI and other components (that primarily reflects RAB growth over the DPP3 period) contributes 25% of the change**;**

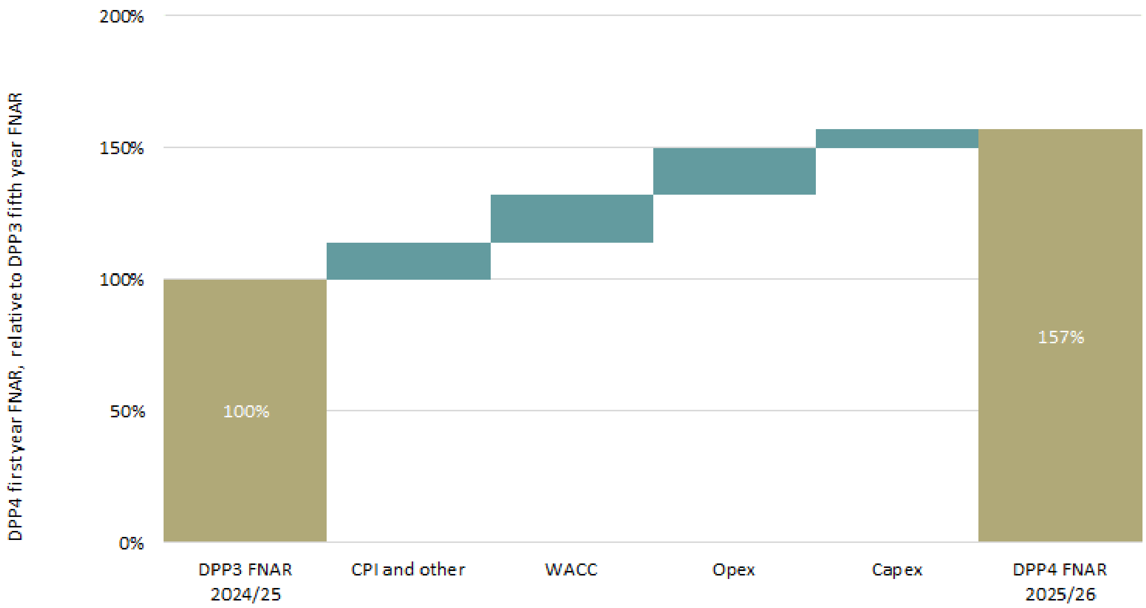
4.9.2 the increase in the estimated cost of capital (WACC) contributes 32%**;**

4.9.3 increases in opex contributes 31%**;** and

4.9.4 increases in capex contributes 12%.

4.10 For a more detailed analysis of these drivers, see **Attachment F**.

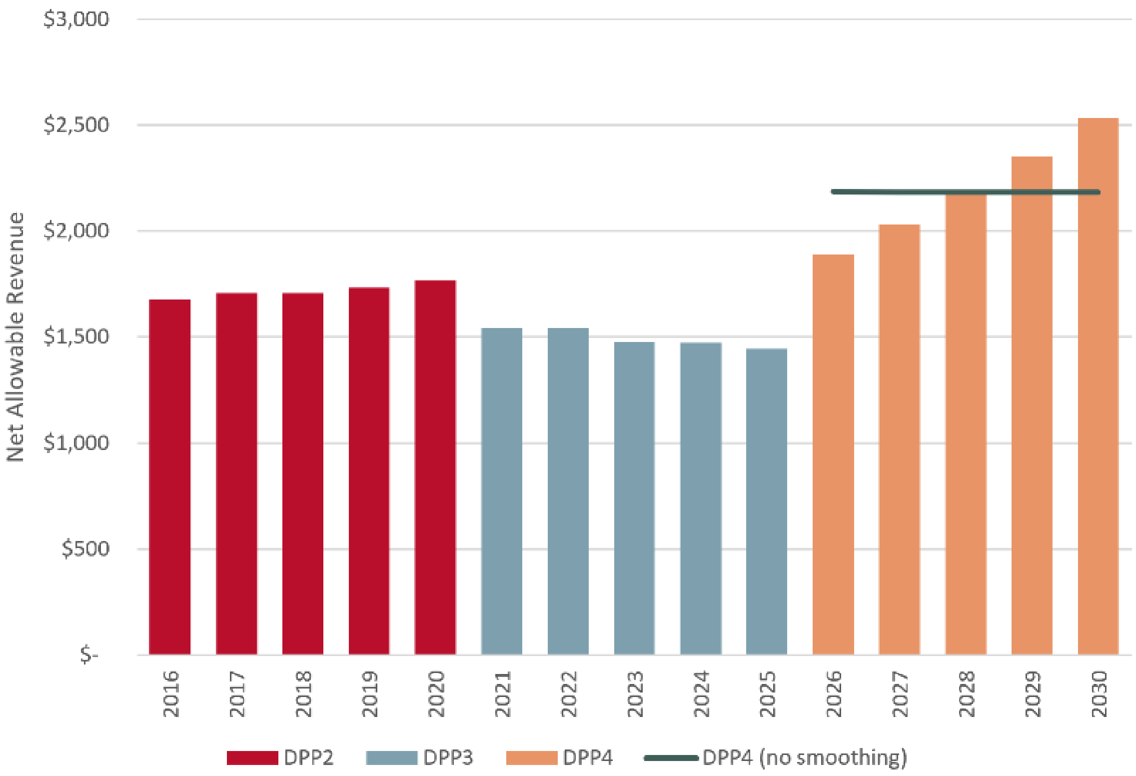
Figure 4.1 Drivers of change in forecast net allowable revenues (FNAR) between DPP3 and DPP4[138]



[138] The item "DPP3 CPI and other" includes changes in opening RAB and other financial model initial conditions over the course of DPP3 (largely driven by higher than forecast inflation), forecasts of CPI over DPP4, depreciation on existing assets, tax, and forecasts of disposed assets. WACC is weighted average cost of capital.

4.11 Under DPP3 settings, consumers have benefitted in the short term from these cost increases not immediately passing through to distribution prices, as shown in Figure 4.2.[139] These declining real revenues have been reflected in consumer bills, where the distribution portion of bills has declined in real terms over the DPP3 period so far.[140]

Figure 4.2 Long-term revenue paths – all DPP EDBs, excluding Aurora (real 2026 $ million)[141]



4.12 However, over the medium and longer term, prolonged price suppression is not in consumers' interests because:

4.12.1 where an EDB's revenue is insufficient to cover its cost, there is a risk that necessary investment will not occur; and

[139] Under DPP3 (and prior to amendments made in the 2023 IM Review), differences between forecast and actual inflation were accrued to the wash-up balance, and available to be recovered on a two-year lag. As discussed below, wash-up balances resulting from this remain largely unrecovered.

[140] Ministry of Business Innovation and Employment "Electricity cost and price monitoring" webpage; see section titled *"Quarterly Survey of Domestic Electricity Prices (QSDEP)."*

[141] On the use of real 2026 dollars here, see section *Explanation of how we have used numbers in this document* in **Chapter 1** paragraph 1.19.

4.12.2 artificial distortions to prices may weaken consumers' incentives to manage demand efficiently, including through investing in DER.

4.13 We also note that while price-smoothing decisions are neutral in present-value terms to EDBs, because deferred revenue is adjusted for inflation, total allowable revenue is higher in nominal terms the more revenue is smoothed to defer revenue recovery.

4.14 There is general acknowledgment of the need to invest in maintaining resilience in response to increased risk of more extreme events, including storm damage or cybersecurity threats. Some EDBs have been exposed to higher costs to respond to such events, and all EDBs have had to reconsider how they forecast expenditure for network resilience to better prepare for a wider range of potential extreme events.

4.15 EDBs are expected to contribute to the energy transition by ensuring networks can support growth and variability in demand and supply. EDBs need to determine where and when the increasing demand for electrification will emerge in their networks, and what traditional solutions, innovative projects and/or non-traditional solutions to invest in to manage demand.

We have heard concerns about consumer bill impacts

4.16 Revenue allowances for EDBs in DPP4 would be recovered by higher prices paid by consumers. We are aware that both the high general inflation across the economy and high interest rates in recent years have added to the wider cost of living challenges facing consumers.[142]

4.17 In response to our draft decision, submitters acknowledged the increase was unavoidable, and most agreed that it was necessary to take steps to mitigate the price shock that consumers would experience.[143] Most agreed that our proposed approach of using alternative rates of change to mitigate the shock was warranted.[144] A few submitters disagreed, and considered that, given the historical under-recovery that occurred during DPP3, deferring any revenue into the later years of the period was not appropriate.[145]

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[142] Reserve Bank of New Zealand webpage "Economic Indicators".

[143] For example: Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 49.

[144] For example: Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 25.

[145] For example: Orion "Submission on EDB DPP4 draft decisions" (11 July 2024), pp. 6 and 19.

4.18 Some submitters also considered that the voluntary undercharging limit, a tool that suppliers could use to further mitigate the price shock for their consumers, did not provide enough flexibility when set at 90%.[146] They considered that 80% was more appropriate to give EDBs sufficient flexibility to smooth the price path in a manner that best fit their specific circumstances.[147] Some also considered that 80% was more appropriate as it would provide EDBs the ability to smooth the 'step off' into DPP5.[148]

We have also heard concerns from EDBs about financeability

4.19 Some EDBs have told us they have concerns about their ability to finance necessary investments in the DPP4 period if significant amounts of revenue are deferred. This issue has been termed 'financeability.'

4.20 We have defined 'financeability' as "the ability of a prudent and efficient notional supplier to raise and repay debt and raise equity in financial markets, readily and on reasonable terms."[149] As we described in **Chapter 2,** the energy sector is in a period of change with some uncertainty as to where, when and how much investment will be required by EDBs. This uncertainty, together with the significant uplift in known investment requirements, heightens financeability concerns.

4.21 We published an issues paper on financeability in February 2024 to ensure we had sufficient information to support DPP4 decisions.[150] In that paper we expressed our view that while financing significant new capacity and new investment is the responsibility of the businesses through normal, efficient capital raising and management, we will consider issues of financeability where they relate to the provision of the regulated service (rather than the financial position of the supplier of that service). We explain how we have taken account of financeability in arriving at our final decisions in the section *Decision P5 – assessing notional EDB financeability*.

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[146] Top Energy "Submission on EDB DPP4 draft decisions" (11 July 2024), and pp. 1-2 and The Lines Company (TLC) "Submission on EDB DPP4 draft decisions" (12 July 2024), pp. 4-5.

[147] The Lines Company (TLC) "Submission on EDB DPP4 draft decisions" (12 July 2024), pp. 4-5.

[148] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 6.

[149] Commerce Commission "DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper" (22 February 2024), para X4.

[150] Commerce Commission "DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper" (22 February 2024).

4.22 Submitters were supportive of the steps we took in our draft decision to address financeability concerns. They considered that our financeability 'sense check' was "practical and transparent" and supported the use of Standard & Poor's (S&P) metrics as part of the sense check.[151] Submitters supported our decision to allow full in-period recovery of building blocks allowable revenue, with ENA noting "the draft DPP4 decision largely ameliorates EDB concerns over the changes' impact on cashflows and financeability."[152]

Decisions on starting prices and revenue smoothing

4.23 This section sets out and explains our decisions on starting prices and revenue smoothing.

4.24 It starts with a brief overview of the components of the revenue path and the relevant terminology. It then covers our final decisions on:

4.24.1 starting prices for each EDB (**decision P1**);

4.24.2 the default rate of change over the regulatory period (**decision P2**);

4.24.3 alternative rates of change (**decision P3**) including how we have assessed consumer price shocks (**decision P4**) and EDB financeability (**decision P5**);

4.24.4 the 'revenue smoothing limit' that applies during the regulatory period (**decisions R2.1 and R2.2**); and

4.24.5 EDBs' ability to apply additional discretionary revenue smoothing via undercharging their allowance (**decision R1.3**).

Overview of the revenue path and terminology

4.25 This section explains the key components of the revenue path, how they operate together to regulate the revenue EDBs can recover, and the terminology we use.

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[151] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 6 and Vector "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 6.

[152] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 8.

Prices vs revenues

4.26 While the term used in s 53M of the Act is 'prices' (hence *price*-quality path), the Act defines 'prices' as including revenues, and allows us to set a revenue cap as the form of control on EDB prices. Under the EDB IMs, EDBs are subject to a revenue cap so we generally refer to revenues for the sake of clarity. Where we refer to 'price' or 'prices', this will generally mean the prices consumers face (or the proxies we use to estimate them).

Controls on revenue

4.27 The regulatory rules and processes that we apply when determining a revenue path for EDBs are set out in Part 3, subpart 1 of the EDB IMs.[153]

4.28 We regulate the revenue EDBs can recover from their customers using two regulatory controls:

4.28.1 the (primary) revenue path that determines the total revenue an EDB may recover from its customers and that is defined in terms of 'forecast allowable revenue'; and

4.28.2 the (secondary) revenue smoothing limit that can require EDBs to defer revenue recovery in a present-value neutral way in some circumstances.

Forecast allowable revenue

4.29 The primary revenue path defined by forecast allowable revenue is made up of four parts:

4.29.1 forecast net allowable revenue, that allows EDBs to recover forecast costs over the regulatory period;

4.29.2 forecasts of pass-through costs, that allow EDBs to pass on certain costs beyond their control to consumers (for example industry levies or transmission charges);

4.29.3 forecasts of recoverable costs, that (largely) implement regulatory adjustments such as wash-ups or incentives amounts; and

4.29.4 forecasts of revenue received under large connection contracts.

[153] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clauses 3.1.1-3.1.4.

4.30 The decisions described below primarily relate to forecast net allowable revenue. Under the EDB IMs and consistent with s 53P(5) of the Act, forecast net allowable revenue over the regulatory period is specified in terms of:

4.30.1 'starting prices' – forecast net allowable revenue in the first year of the regulatory period;[154]

4.30.2 the annual change in forecast CPI;[155] and

4.30.3 an annual rate of change relative to forecast CPI, or 'X-factor'.

Decision P1 – starting prices

4.31 Our final decision is to determine the starting price for each non-exempt EDB using a building blocks model, and to not defer any building blocks allowable revenue (BBAR) into DPP5.

4.32 As noted above in describing the twin price shock and financeability challenges the sector faces, EDBs' costs have risen significantly such that rolling their current revenue paths forward would not provide the ex-ante expectation of a normal return.[156] As explained in more detail in **Attachment F**, this 'roll-over' counter factual would see EDBs under-recover their forecast costs by around 33% on average.

4.33 The final starting prices and rates of change for each EDB are set out in Table 4.1.[157] The changes in total distribution revenue (including wash-up drawdown amounts and IRIS incentive amounts) that results from this is shown in Figure 4.3.

[154] Starting prices are specified in Schedule 1.1 of the EDB DPP4 determination.

[155] The methodology for calculating CPI is specified in Schedule 1.3(2) of the EDB DPP4 determination.

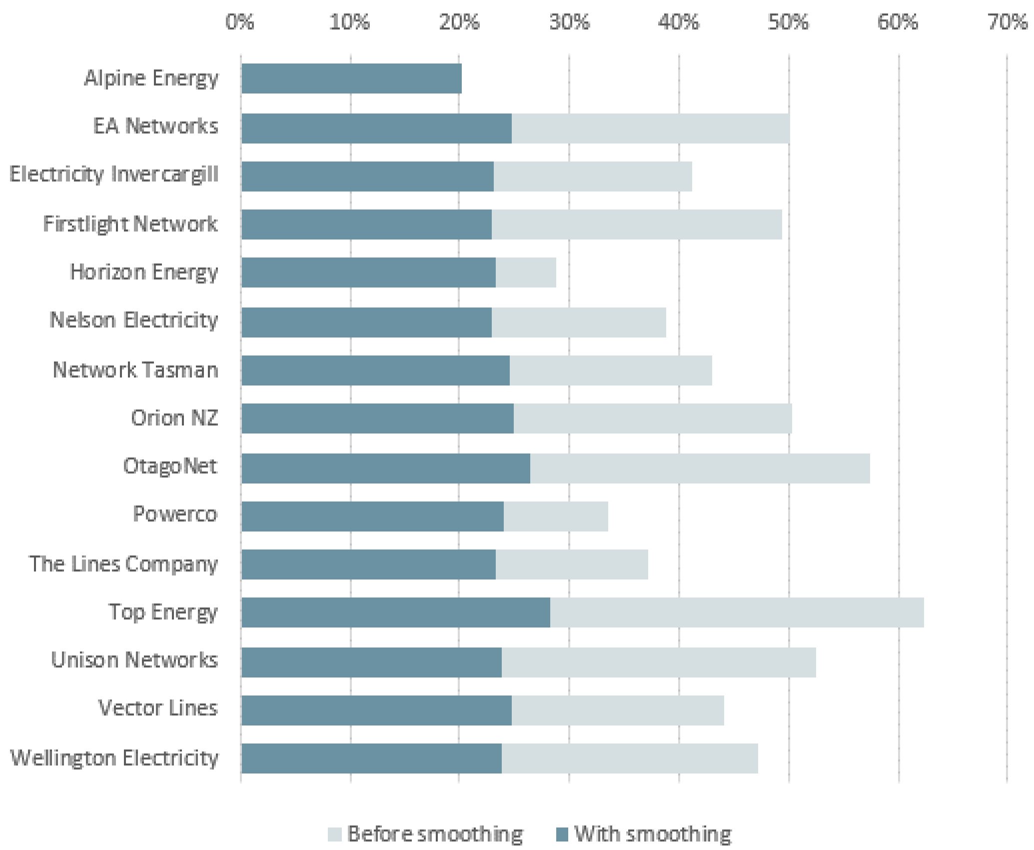
[156] Section 53P(3) specifies that we must set starting prices by either rolling forward the prices that applied at the end of the preceding regulatory period, or that are determined by the Commission based on the current and projected profitability of each supplier.

[157] As the CPI component of the change in forecast net allowable revenue is determined based on updated values each year of the regulatory period, it is not set out here. This change was made as part of the 2023 IMs review.

Table 4.1 DPP4 starting prices and rates of change

EDB	Starting prices – FNAR in 2026 ($m)	X-factor – rate of change relative to CPI [158]
Alpine Energy	73.4	0.0%
EA Networks	44.3	(10.7%)
Electricity Invercargill	16.9	(7.7%)
Firstlight Network	34.3	(10.2%)
Horizon Energy	34.1	(2.4%)
Nelson Electricity	7.2	(7.1%)
Network Tasman	37.2	(8.3%)
Orion NZ	231.4	(9.8%)
OtagoNet	34.6	(12.3%)
Powerco	446.2	(3.9%)
The Lines Company	48.6	(6.0%)
Top Energy	51.7	(13.5%)
Unison Networks	133.4	(11.8%)
Vector Lines	579.4	(8.0%)
Wellington Electricity	118.7	(9.6%)

Figure 4.3 Nominal change in smoothed distribution revenue 2025 to 2026[159]



4.34 In Figure 4.3 the pale blue bars ("Before smoothing") show what the change in distribution revenue would be without any smoothing, discussed further below. The dark blue bars ("With smoothing") show the change in distribution with smoothing. These figures average around 24% in nominal terms. This is consistent with:

4.34.1 our decision to cap the real per ICP increases at 20% in most cases;[160]

4.34.2 forecast CPI of 2.3%; and

4.34.3 average ICP growth (across 15 EDBs) of 1.1%.

4.35 Variations between EDBs are explained by:

4.35.1 variations in forecast ICP growth (between 0.2% to 3.0%); and

4.35.2 for Top Energy, our decision to allow a 24% real per ICP increase in 2026 to limit on-going price shocks over the regulatory period.

4.36 On balance, we consider allowing EDBs to fully recover BBAR and any accrued wash-up amounts within the DPP4 regulatory period, with no deferral into DPP5, better promotes the purpose of Part 4 than the alternatives. This decision is unchanged from DPP3 and prior resets. Deferring revenue into DPP5 would reduce short-term price changes for consumers. However, it would also:

4.36.1 adversely impact EDB incentives to invest and financeability metrics for EDBs; and

4.36.2 distort the recovery of revenue over time, reducing the efficiency benefits of cost-reflective prices.

4.37 Deferral of revenue increases over the short term (within a regulatory period) has less of an effect on the outcomes in the Part 4 purpose described above and is discussed below in relation to alternative rates of change.

[160] 20% in year 1 (except if that would lead to >10% year-on-year for years 2-5) and then 10% year-on-year for years 2-5.

Decision P2 – default rate of change

4.38 Section 53P(1) of the Act requires us to determine a 'rate of change', which is used to determine net revenue for each year after the first of the regulatory period. The rate of change comprises:

4.38.1 the rate of increase in forecast CPI, the treatment of which is determined in the specification of price IMs; and

4.38.2 a default rate of change relative to forecast CPI (the default X-factor).

4.39 Our decision is to determine a default X-factor of 0%.

4.40 Because our decision is to set starting prices using a building blocks model, the forecast net allowable revenue over the period already incorporates forecast changes in productivity, so the rate of change in productivity in the EDB sector relative to the economy as a whole will be 0%.[161] Our decision is therefore to set a default X-factor of 0%. This view was supported by submissions on the DPP4 Issues paper.[162]

4.41 Given the decisions below on alternative rates of change to mitigate price shocks, the default rate of change will only apply to one EDB (Alpine).

Decisions P3, P4, and P5 – alternative rates of change, price shocks and financeability

4.42 Section 53P(8) of the Act gives us discretion when resetting a DPP to set 'alternative rates of change' for a particular supplier(s). This is a tool that can be used to manage the challenge of mitigating price shocks to consumers, while avoiding imposing undue financial hardship on suppliers.

4.43 Our approach to smoothing forecast net allowable revenue via alternative rates of change is made up of three interlocking decisions:

4.43.1 the alternative rates of change we set (**decision P3**);

4.43.2 our approach to considering consumer price shocks (**decision P4**); and

4.43.3 our approach to considering EDB financeability (**decision P5**).

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[161] For more detail, see Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), p. 55 and **Attachment H**.

[162] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 17; Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 21; Orion "DPP4 Issues paper submission" (19 December 2023), p. 24; Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 24 and Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 74.

4.44 The smoothing we apply to EDBs' net allowable revenue is supported by our application of a 'revenue smoothing limit' as a secondary control on increases including recoverable costs. EDBs also have the ability to smooth revenues via temporary undercharging within the undercharging limit (discussed in more detail below).

Decision P3 – alternative rates of change

4.45 The specific alternative rates of change for each EDB are set out in Table 4.1. We have based these rates on:

4.45.1 allowing full recovery of BBAR and previously accrued wash-up balances over DPP4;

4.45.2 constraining price increases (in the terms discussed below) to 20% (or approximately 6% on an average household retail bill) between DPP3 and DPP4;

4.45.3 constraining price increases over the remainder of the regulatory period to 10% per year; and

4.45.4 evidence of financeability positions suppliers may face (based on the assessment discussed below).

4.46 Where limiting the initial and on-going price shocks on this basis would result in deferral of building blocks allowable revenue into DPP5, our decision is to allow an initial increase in estimated prices greater than 20%. This applies to one EDB: Top Energy.

4.47 For Top Energy, we have allowed an initial change in real distribution revenue per ICP of 24%. This limits on-going annual revenue per ICP (price) increases to 10% without deferral of revenue into DPP5.

4.48 We do not consider it necessary to adjust our decision on alternative rates of change for financeability reasons for any EDB. Our notional analysis of post-smoothing prices (ie, after starting price adjustments and alternate X-factors have been applied), shows all EDBs meet the BBB+ reference level for our primary financeability metric, FFO/Debt.[163] Four EDBs (Alpine, Firstlight, Orion and Powerco) achieve a mid-range BBB level by our second metric, Debt/EBITDA. However, adopting an alternative revenue profile would not change this result for these four EDBs. Part of the reason for this outcome is large negative IRIS balances for these businesses. Adopting an alternative revenue profile would not change the whole-period financeability results for these EDBs. As such we do not consider that making additional changes would better promote the Part 4 purpose.

4.49 The increase in initial distribution revenue for Alpine is less than 20% in real per ICP terms. As a result, we have not applied an alternative rate of change for Alpine.

4.50 As alternatives to our chosen approach to smoothing (allowing a relatively larger initial increase followed by smaller increases over the remainder of the regulatory period), we also considered:

4.50.1 no smoothing (allowing the full revenue increase in year one of the period, with growth at CPI over the remainder of the period); and

4.50.2 uniform (or maximum) smoothing, such that the annual change in year one of the period is the same as the annual change in the subsequent years of the period.

4.51 The 'no smoothing' option would lead to an estimated initial price shock in year one of DPP4 ranging between 17% and 57% in real terms for each EDB, with a weighted average of 38% across EDBs. We consider that in current circumstances, a starting price increase above 20% would constitute a 'price shock' for consumers, and as such have chosen to implement alternative rates of change in keeping with s 53P(8) of the Act.

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[163] The BBB+ reference levels for our financeability metrics are for Funds From Operations over notional Debt (FFO/Debt > 13%) and notional Debt over Earnings Before Interest, Tax, Depreciation and Amortisation (Debt/EBITDA < 4.0). See *Decision P5 – assessing notional EDB financeability* below, and **Attachment G**.

4.52 The 'uniform smoothing' option would lead to a lower initial price shock but would give rise to annual real increases in estimated prices of around 10% on average, and as high as 14% for one EDB. As well as deferring EDBs' revenue recovery and potentially detrimentally affecting financeability,[164] the uniform smoothing option provides less room to adjust in the out-years without creating price shocks should revenue grow from reopeners.

4.53 Submissions on our draft decision were generally supportive of our draft approach to mitigate the initial price shock.[165] We received multiple submissions on the balance of initial price shock versus continued price increases, both to bring revenue forward in the period and to defer more revenue to the out years. [166,167]

4.54 After considering submissions, we have decided to retain our draft decision. We consider that the combination of a 20% real initial price increase and 10% year-on-year increases provides a balance between:

4.54.1 protecting consumers from a substantial initial price shock;

4.54.2 allaying financeability concerns for EDBs by allowing full in-period recovery of building blocks allowable revenue; and

4.54.3 providing some headroom in out-years for additional revenue from reopeners to be included without creating a mid-period price shock.

4.55 As noted further below when discussing the under-charging limit, where an EDB wishes to smooth prices to a greater extent than what we have required, they can do this by: [168]

4.55.1 delaying recovery of outstanding DPP3 wash-up balances; and

4.55.2 deferring up to 10% of each year's forecast allowable revenue.

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[164] Deferral of more revenue into the out-years of DPP4 adversely impacted the notional financeability position of some EDBs.

[165] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 25.

[166] Orion "Submission on EDB DPP4 draft decisions" (11 July 2024), p. 6, 19; Energy Trusts of New Zealand (ETNZ) "Submission on EDB DPP4 draft decisions" (11 July 2024), p. 2.

[167] Major Electricity Users Group (MEUG) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 6.

[168] In their submissions on the DPP4 draft decisions, several EDBs indicated they intended to do so: Submissions by Top, Tasman and TLC on the Commerce Commission "EDB DPP4 draft decision" (12 July 2024).

Decision P4 – assessing price shocks for consumers

4.56 We have assessed price shocks for consumers both at the start of and over the course of the regulatory period:

4.56.1 based on 'distribution revenue' – that is forecast net allowable revenue plus recoverable costs (principally IRIS incentive amounts and wash-up drawdowns);[169]

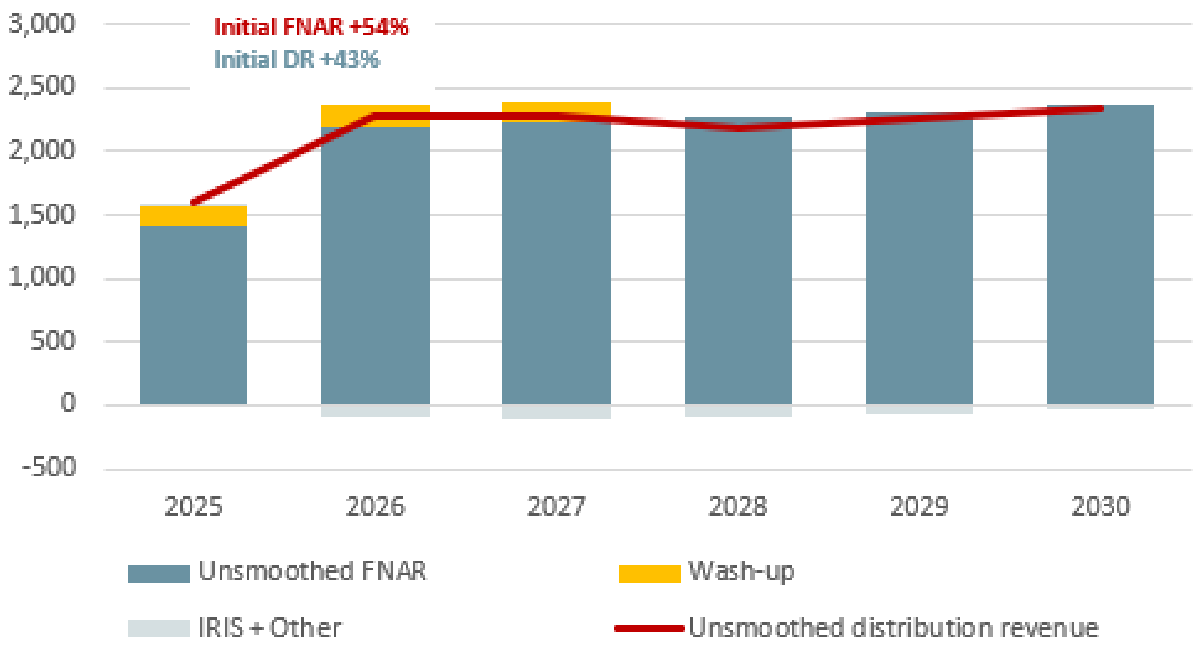
4.56.2 in real terms (net of forecast CPI); and

4.56.3 on a per ICP basis as a proxy for demand growth.

4.57 We chose to analyse price shocks in distribution revenues because wash-up drawdowns, IRIS incentives and other recoverable costs can have a material influence on the revenue EDBs recover from their consumers. Analysing this more inclusive measure of allowable revenue shows a change of 43% in nominal terms.

4.58 As illustrated by Figure 4.4, were we to ignore this impact the unsmoothed change in FNAR would be 54% in nominal terms across all non-exempt DPP EDBs. As explained in more detail in **Attachment F**, the impacts for different EDBs vary significantly.

Figure 4.4 Unsmoothed distribution revenue – all DPP EDBs (excluding Aurora)



[169] Distribution revenue excludes transmission charges and other pass-through costs.

4.59 We have assessed price shocks in real terms. Assessing price shocks in nominal terms risks suppressing EDBs' real revenues which could lead to substantial future wash-up balances (as has been the case over DPP3), resulting in price shocks in the future. While this would be present-value neutral to EDBs, consistent with the FCM principle, substantially deferring the timing of cashflows may cause financeability concerns.

4.60 Finally, we have used a per ICP measure rather than a total revenue measure to serve as a proxy for the impact on consumer prices. Where a network is forecast to see higher growth (and is spending and investing to meet this growth) price shocks could be mitigated by increasing revenues being spread over an increasing number of consumers. The ICP forecasts we have used here are the same ones applied in our forecasts of opex scale growth.[170]

4.61 Some submitters on the draft decision considered that we should use demand growth rather than ICP growth.[171] We consider that there is more volatility in demand growth, and that forecasts of demand growth are not as easily verifiable. While we have not attempted to assess the impact of growth in (per-user) demand, eg, in kWh or peak kWh terms, we note that where EDBs see such demand growth due to wider electrification, price shocks may be further mitigated.

4.62 Figure 4.5 shows the estimated average consumer bill impact for each EDB between 2025 and 2026.

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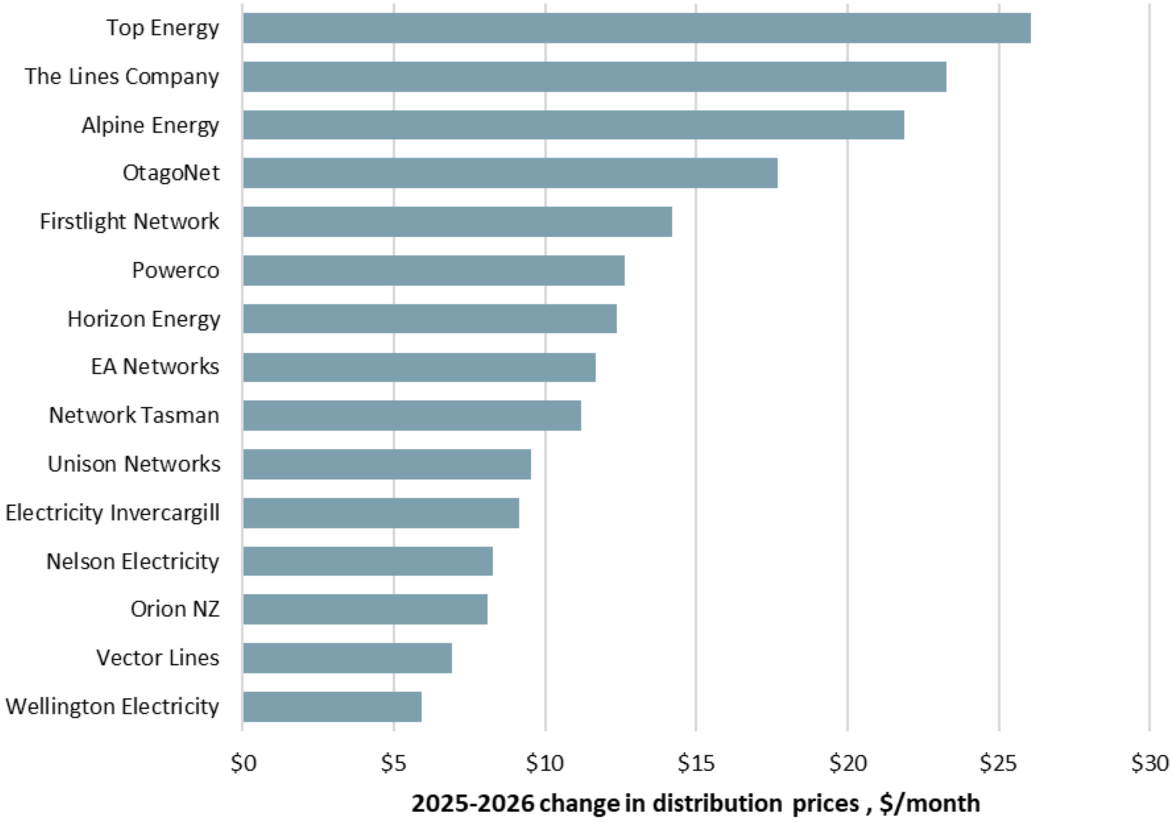
[170] Using ICP count trends from ID data, see *O5.5, O5.6 and O5.7 decisions on forecasting scale growth factors* in **Attachment C**.

[171] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 5-6, Alpine Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 4-5.

Figure 4.5 Estimated average increase in monthly distribution component of a household's electricity bill from DPP3 to DPP4



Decision P5 – assessing notional EDB financeability

4.63 We have applied a financeability sense check to our final revenue smoothing decisions, given the importance stakeholders have placed on financeability in previous consultations, and because of the potential impact on incentives for EDBs to invest. This sense check serves as a support tool for making decisions, not a deterministic test with thresholds and prescriptive responses.

4.64 Our approach is to leverage the established S&P's credit rating methodology. For each EDB we have assessed core S&P financial metrics using a notional analysis against the levels consistent with a BBB+ credit rating. This approach is presented in detail in **Attachment G** of this paper, and was widely supported in submissions on the draft decision.

4.65 Two core financial metrics we considered are:

4.65.1 funds from operations (FFO) as a percentage of notional debt; and

4.65.2 notional debt to EBITDA.[172]

4.66 We also evaluated:

4.66.1 FFO interest cover ratio; and

4.66.2 notional leverage based on forecast free cashflows.

4.67 On this notional analysis, all EDBs meet the BBB+ reference level for our primary metric (FFO/Debt > 13%).

4.68 Firstlight, Orion, Powerco and Alpine do not meet the BBB+ reference level for our second metric, Debt/EBITDA < 4. These EDBs have Debt/EDBITDA ratios between 4.1 and 4.4 corresponding to a BBB level. These results reflect substantial negative IRIS balances and large capex expenditure programs.[173] Alpine is currently under investigation in relation to historical depreciation errors, the outcome of which may impact its notional financeability sense check results.

[172] Earnings Before Interest Tax Depreciation and Amortisation, calculated as revenue less opex.

[173] Additionally, because Powerco transitioned to the DPP in 2023 and its revenue allowance was determined based on (higher) forecasts of inflation at that time, it has not accrued the same level of positive washup balance due to unforecast CPI inflation as other EDBs who have been on the DPP since 2021.

4.69 Adopting an alternative revenue profile would not change this result for these four EDBs. With part of the cause being large negative IRIS balances, we do not consider that making additional changes would better promote the Part 4 purpose and we have not made adjustments on financeability grounds.

Decision R2.1 and R.2.2 – revenue smoothing limit

4.70 In addition to smoothing net allowable revenues via alternative rates of change, we also managed potential price shocks caused by recoverable costs via the revenue smoothing limit.

4.71 As part of the 2023 IM Review, we made a package of changes to more efficiently allocate the risk of revenue volatility in the context of higher and less predictable inflation and greater uncertainty about the future development of energy networks.[174]

4.72 The effect of the revised IMs is to limit the role of the 'revenue smoothing limit' (RSL) to smoothing year-on-year changes in forecast net allowable revenue and recoverable costs within a regulatory period. Specifically, the RSL is intended to prevent the combined impact of wash-up drawdowns, IRIS and quality incentives, or other recoverable costs from causing revenue and price volatility. It does not apply to pass-through costs (which now includes transmission charges – any smoothing of Transpower's revenue is a matter for the IPP and transmission pricing methodology).

4.73 **Decision R2.1** is to specify the RSL with reference to the sum of forecast net allowable revenue for the current year and forecast recoverable costs for the previous year, with adjustments to preserve the revenue path for forecast net allowable revenue and for CPI. This is consistent with our decision to allow EDBs the opportunity to recover DPP4 net allowable revenue and any wash-ups already accrued over DPP3 within the DPP4 period and aligns with decisions in the 2023 IM Review on the treatment of inflation.

4.74 **Decision R2.2** is to set the revenue smoothing limit at 10% over and above the X-factor and CPI adjustments. In effect, this will only apply to changes in revenue caused by changes in recoverable costs.

[174] See Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), paragraph 7.5, p. 79 and, for more detail: Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), Attachment D.

4.75 Defining the limit relative to each year's forecast net allowable revenue and recoverable costs means that in most cases, an EDB should be able to recover its full revenue entitlement over the regulatory period. The 10% limit was informed by analysing historical volatility in EDB revenue and recoverable costs.[175] As shown in Table 4.2, this differs from the 'limit on the annual maximum percentage increase in forecast revenue from prices (FRP)' under DPP3.

Table 4.2 Revenue smoothing limit decisions vs DPP3 limit on increase in FRP

DPP4 decisions: Revenue smoothing limit	DPP3: Limit on increase in FRP
In effect, applies only to increases in revenue caused by increases in recoverable costs.	Applied to total forecast revenue from prices, including transmission charges and pass-through costs.
Preserves EDBs' expectation of recovering NPV of BBAR within the regulatory period.	In extreme cases, potential for some deferral of BBAR into the following regulatory period.
Applied on a real (CPI-adjusted) basis; EDBs do not bear inflation risk.	Applied on a nominal basis; EDBs bear inflation risk.

4.76 We consider this approach meets the need for revenue smoothing to protect consumers from mid-period price shocks arising from volatility in recoverable costs, while also ensuring that suppliers can expect full recovery of revenue during the DPP regulatory period under most circumstances.

Decision R1.3 – undercharging limit

4.77 Finally, in addition to the revenue smoothing we require EDBs to undertake via alternative rates of change and the revenue smoothing limit, EDBs have the ability to under-recover their allowable revenue on a temporary basis via undercharging.

4.78 To enable this, where an EDB considers it in their customers' interests and has the financial capacity to do so, we have specified an undercharging limit (the point at which voluntary under-recovery does not accrue to the wash-up account) at 90% of forecast allowable revenue. As with DPP3, we have specified this limit to allow EDBs some flexibility to smooth their revenue recovery, while at the same time minimising the risk of future price shocks.

[175] See **Attachment F** for more detail on the analysis supporting our draft decisions on the RSL.

4.79 Some submissions on our draft decision considered that 90% of forecast allowable revenue did not provide EDBs with sufficient flexibility to mitigate the full range of scenarios that a business might wish to utilise the ability to undercharge, and considered that 80% was a more appropriate level.[176] In the 2023 IM Review, changes were made to allow an EDB discretion about when to draw down its wash-up balance as it becomes available. We consider this change, and the 90% voluntary undercharging limit, provide an EDB flexibility to shape a revenue path that best suits its specific circumstances and mitigates the risk to consumers associated with greater discretion. As such we are retaining our draft decision.

Decisions on other aspects of the revenue path

4.80 We are implementing amendments to the wash-up from the 2023 IM Review. The revenue path includes a 'wash-up' mechanism that manages defined uncertainties by making consumers or EDBs whole in present-value terms for differences between forecasts and actual.[177] As part of the 2023 IM Review, we made a number of changes to the wash-up mechanism, with the intent of improving the mechanism's functionality.

4.81 We included a wash-up for differences between forecast and actual CPI in year one of a regulatory period. We also made a number of other changes to the mechanism to improve the speed that an EDB can draw down on any wash-up balance that may accrue over the course of the regulatory period.

4.82 Schedules 1.7 and 1.8 of the DPP4 final determination implement the changes arising from the 2023 IM Review (**decision R3.1**).

4.83 The revised IMs provide for the following specific matters to be decided in setting DPP determinations (see **Attachment F** for further discussion):

4.83.1 **Decision R3.2** (calculation of the year-one inflation wash-up) is that, for the purpose of calculating the new wash-up for inflation in the first year of a regulatory period:

4.83.1.1 'forecast CPI change' is 2.27%; and

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[176] Top Energy "Submission on EDB DPP4 draft decisions" (11 July 2024), pp. 1-2 ; The Lines Company (TLC) "Submission on EDB DPP4 draft decisions" (12 July 2024), pp. 4-5.

[177] The list of what is covered by the wash-up is defined in clause 3.1.4 of the EDB IMs, Commerce Commission, "Electricity Distribution Services Input Methodologies Determination 2012" – (consolidated as of 23 April 2024).

4.83.1.2 'actual CPI change' is specified in accordance with the formula:

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

Where: $\boldsymbol{CPI_{q,t-n}}$ is the CPI for the quarter year ending $\boldsymbol{q}$ in the 12-month period $\boldsymbol{n}$ years prior to the year $\boldsymbol{t}$; and $\boldsymbol{t}$ is the year 2026.

4.83.2 **Decision R3.3** (base wash-up drawdown) is not to specify a base wash-up drawdown amount for non-exempt EDBs, in DPP4.

4.83.3 **Decision R1.4** (LCC compliance) is to include an LCC wash-up term in the wash-up accrual formula, to avoid recovery of LCC under-recovered revenue from other consumers and correct over-allocation to LCC revenue from non-qualifying LCCs.

Decisions on other inputs to the financial model

4.84 In addition to forecasts of expenditure and decisions on revenue smoothing, we need to make a number of decisions about other inputs to the DPP financial model:

4.84.1 **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;

4.84.2 **decision M1:** the weighted average cost of capital (WACC) in the final financial model is 7.10%;[178]

4.84.3 **decision M2:** to include an allowance for disposed assets, based on historical levels;

4.84.4 **decision M3:** forecast depreciation on existing assets based on information provided by each EDB;

4.84.5 **decision M4:** use base year data from 2024 information disclosures in our final decisions; and

[178] Commerce Commission, " Cost of capital determination for electricity distribution businesses' default price-quality path commencing 2025 and Transpower New Zealand Limited's 2025-2030 individual price-quality path [2024] NZCC 21" (25 September 2024)

4.84.6 **decision M5:** for CPI forecasts, use the most recently available Reserve Bank of New Zealand monetary policy statement forecasts from when the WACC was determined.[179]

4.85 We discuss these decisions in more detail in **Attachment I**.

[179] The DPP4 final decision was prepared on the basis of Reserve Bank inflation forecasts from the August 2024 Monetary Policy Statement.