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Default price-quality paths for electricity distribution businesses from 1 April 2020 – Updated draft models

Companion paper

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Associated documents

Publication date	Reference	Title
31 January 2019	ISSN 1178-2560	Electricity Distribution Services Input Methodologies Determination 2012 – Consolidated as of 31 January 2019
28 November 2014	ISBN 978-1-869454-12-8	Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy paper
28 November 2014	[2014] NZCC 33	Electricity Distribution Services Default Price-Quality Path Determination 2015
9 November 2017		Our priorities for the electricity distribution sector for 2017/18 and beyond
14 June 2018	ISBN 978-1-869456-42-9	Default price-quality paths for electricity distribution businesses from 1 April 2020 – Proposed Process
23 August 2018	ISBN 978-1-869456-53-5	Proposed amendments to Electricity Distribution Services Input Methodologies Determination in relation to accelerated depreciation – Draft reasons paper
6 September 2018		Default price-quality paths for electricity distribution businesses from 1 April 2020 – Process Update Paper
8 November 2018	[2018] NZCC 19	Amendment to Electricity Distribution Services Input Methodologies Determination in relation to accelerated depreciation
15 November 2018	ISBN 978-1-869456-70-2	Default price-quality paths for electricity distribution businesses from 1 April 2020 – Issues Paper
29 May 2019	ISBN 978-1-869457-00-6	[DRAFT] Electricity Distribution Services Default Price-Quality Path Determination 2020
29 May 2019	ISBN 978-1-869456-98-6	Proposed amendments to Input Methodologies for electricity distributors and Transpower New Zealand Limited: Reasons paper
29 May 2019	ISBN 978-1-869456-99-3	[DRAFT] Electricity Distribution Services Input Methodologies Amendments Determination 2019
29 May 2019	ISBN 978-1-869457-05-1	Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision – Reasons Paper

Commerce Commission
Wellington, New Zealand

Contents

Chapter 1 Introduction

Purpose of this paper

1.1 The purpose of this paper, and the models published alongside it, is

1.1.1 to provide stakeholders with updated draft allowable revenues and quality standards for the default price-quality path (DPP) for electricity distribution businesses (distributors);

1.1.2 to provide an opportunity for technical feedback on these models; and

1.1.3 to seek feed back on targeted revised policy decisions.

1.2 We have taken the step of publishing this paper to provide stakeholders with a better reflection of our draft decision incorporating:

1.2.1 the most up-to-date data from 2019 Information Disclosures;

1.2.2 the final weighted-average cost of capital (WACC) determination; and

1.2.3 updated data from other sources (eg: NZIER forecasts).

1.3 We are seeking feedback from interested parties on:

1.3.1 the accuracy and workability of the models for allowable revenues and quality standards summarised in Chapter 2 and 3;

1.3.2 whether any alternate rates of change are necessary to prevent financial hardship to distributors or price-shocks for consumers;

1.3.3 the updated approach to system growth capex;

1.3.4 the proposed new approach to normalisation.

1.4 We welcome your views on these matters within the timeframes below:

1.4.1 submissions by 5pm on **Wednesday 9 October 2019**; and

1.4.2 cross-submissions by 5pm on **Wednesday 16 October 2019.**

Status of this modelling update

1.5 This paper is not a full update to our draft decision. On 18 July 2019, we received submissions on our draft DPP decision, and cross-submissions on 12 August 2019. We are still considering these submissions, and will include our response to the full range of issues raised in our final decision.[1]

Changes to incorporate treatment of operating leases

1.6 The models published alongside this paper incorporate structural changes to allow for our proposed treatment of operating leases. However, given timing and data-quality constraints, we have not included the necessary operating lease data. For the purposes of this updated draft model, all numeric values have been set to zero.

1.7 Businesses wishing to assess the expected impact of the change in treatment of operating leases on their DPP3 opex and capex forecasts as used in the financial and IRIS models should insert the s 53ZD data they have provided to the Commission into the input sheet of the operating lease model. The table headers in the input sheet for the operating lease model correspond to headers that appear in the Excel template issued with the section 53ZD notice. These should then be linked to the opex projections model and the capex projections and capex projections feeder models.

1.8 We intend to replace the contents of the input table in the operating lease model with aggregate pivot table data, collating the responses to our section 53ZD notice for operating lease information that we issued to non-exempt EDBs on 19 July 2019. Information from the responses needs to be clarified in some cases and adjustments made where necessary. We note that several distributors have advised they do not intend to capitalise the value of any leases.

Issues relating to SAIFI data

1.9 Due to issues identified during the process of distributors' providing updated section 53ZD responses on quality of service, most distributors have not been able to provide audited responses to this information. As a result, SAIFI components of the quality standards discussed in this paper may change significantly between now and the final decision.

1.10 The issue relates to the treatment of 'subsequent outages'; where supply is temporarily restored to customers for a period of time, before being interrupted again.

[1] Details of our draft decision, and the submissions we received in response can be found on our website at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-price-quality-paths/electricity-lines-default-price-quality-path/2020-2025-default-price-quality-path

1.11 We intend to consult with interested parties on this issue shortly, and are continuing to engage with distributors and their auditors to resolve these issues.

How we have structured this paper

1.12 Chapter 2 of this paper sets out the updated draft allowable revenues for each distributor, and briefly explains:

1.12.1 what has changed since our draft decision; and

1.12.2 the factors driving changes in those allowable revenues, relative to current revenues.

1.13 Chapter 3 does the same for our proposed quality standards and incentives.

1.14 Chapter 4 sets out our new proposed approach to scrutinising system growth capex forecasts, having considered submissions we received on our draft decision about this issue.

1.15 Chapter 5 sets out a proposed new approach to normalisation for quality standards and incentives (note that these changes have not been incorporated in the models published alongside this paper).

1.16 The Attachment to this paper provides technical details of the changes we have made to the allowable revenue and quality models since the draft decisions, and changes in the data they rely on.

Material published alongside this paper

1.17 Alongside this paper, we have published;

1.17.1 an updated suite of financial and expenditure models used to determine allowable revenues; and

1.17.2 updated quality of service models used to determine quality standards and incentives.

1.18 The Commission has also published the WACC determination for the DPP and for customised price-quality paths (CPPs) today. This cost of capital will apply for determining allowable revenue for distributors on both the DPP and on CPPs.

Process we are following

1.19 This section explains the process we intend to follow in advance of the final decision, and how you can provide your views.

Process from here to the final decision

Next steps before our final decision

1.20 We are seeking submissions on this paper and the associated models within the timeframes and process discussed further below. The scope of this consultation is our updated approach to system growth capex discussed in Chapter 4, the approach to normalisation in Chapter 5, and the application of any alternate rates of change.

1.21 We may also engage with some distributors directly to resolve any issues identified with the data used in our modelling.

1.22 Distributors who have sought an extension for providing audited reliability data in response to our 28 June 2019 section 53ZD request must provide this information before 25 October 2019. This data will be used in determining our final decision.

Final decisions on the DPP and related Input Methodology amendments

1.23 We intend to publish final amendments to the Input Methodologies (IMs) necessary to implement our DPP decisions by 26 November 2019. The final DPP decision will be published on 27 November 2019.

1.24 Following the publication of the final decision, we propose issuing guidance to aid distributors in understanding their compliance obligations under the DPP. This may include publishing demonstration models to aid in understanding the revenue cap with wash-up and the normalisation process for reliability standards.

How you can provide your views

Timeframe for submissions

1.25 We welcome your views on the matters raised in this paper and on the accompanying models, within the timeframes below:

1.25.1 submissions by 5pm on **Wednesday 9 October 2019**; and

1.25.2 cross-submissions by 5pm on **Wednesday 16 October 2019**.

1.26 Due to time constraints, we will not be able to offer any extensions to these timeframes, or consider late submissions.

Matters outside the scope of this consultation

1.27 We are not seeking submissions on the full range of decisions proposed in our draft decision (such as our approach to expenditure forecasting, uncertainty mechanisms, or quality standards). We received submissions and cross-submissions on these decisions in response to our draft decision. We are still considering these submissions, and will include our response to the full range of issues raised in our final decision.

Address for submissions

1.28 Responses should be addressed to:

Dane Gunnell (Manager, Price-Quality regulation)
c/o regulation.branch@comcom.govt.nz

1.29 Please include "EDB DPP3 reset" in the subject line of your email. We prefer submissions in both a format suitable for word processing (such as a Microsoft Word document) as well as a 'locked' format (such as a PDF) for publication on our website.

Confidential submissions

1.30 While we discourage requests for non-disclosure of submissions so that all information can be tested in an open and transparent manner, we recognise that there may be cases where parties that make submissions wish to provide information in confidence.

1.31 We offer the following guidance:

1.31.1 If it is necessary to include confidential material in a submission, the information should be clearly marked, with reasons why that information is confidential.

1.31.2 Where commercial sensitivity is asserted, submitters must explain why publication of the information would be likely to unreasonably prejudice their commercial position or that of another person who is the subject of the information.

1.31.3 Both confidential and public versions of the submission should be provided.

1.31.4 The responsibility for ensuring that confidential information is not included in a public version of a submission rests entirely with the party making the submission.[2]

[2] Parties can also request that we make orders under section 100 of the Act in respect of information that should not be made public. Any request for a section 100 order must be made when the relevant information is supplied to us, and must identify the reasons why the relevant information should not be made public. We will provide further information on section 100 orders if requested by parties. A key benefit of such orders is to enable confidential information to be shared with specified parties on a restricted basis for the purpose of making submissions. Any section 100 order will apply for a limited time only as specified in the order. Once an order expires, we will follow our usual process in response to any request for information under the Official Information Act 1982.

1.32 We request that you provide multiple versions of your submission if it contains confidential information or if you wish for the published electronic copies to be 'locked'. This is because we intend to publish all submissions on our website. Where relevant, please provide both an 'unlocked' electronic copy of your submission, and a clearly labelled 'public version'.

Chapter 2 Updated draft revenue and expenditure allowances

Purpose of this chapter

2.1 This chapter sets out and briefly explains updates to our proposed draft:

2.1.1 allowable revenue in the first year of the DPP3 period (starting prices);

2.1.2 opex allowances;

2.1.3 capex allowances; and

2.1.4 other inputs to the financial model.

2.2 For each of these components, we discuss:

2.2.1 how they have changed since our draft decision;

2.2.2 the factors driving these changes; and

2.2.3 factors that may change between now and the publication of the final decision.

Proposed allowable revenue

'Prices' versus revenues—our terminology

2.3 The price path for DPP3 will apply to distributors as a 'revenue cap'. A revenue cap limits the maximum revenues a distributor can earn, rather than the maximum prices that it can charge.[3] For this reason, while the terminology in the Act refers to a 'price path' and 'starting prices', in this paper we generally refer to the 'allowable revenues' a distributor can earn.[4]

2.4 The price path is expressed 'net of pass-through and recoverable costs.' Generally in this paper, where we discuss 'revenue' or 'allowable revenue', this means 'net' revenue (excluding pass-through and recoverable costs, such as Transpower's transmission charges). Where we are discussing 'gross' revenue, we have indicated as such.

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3 The decision to move distributors from a price cap to a revenue cap was made as part of the IM review in 2016. Commerce Commission "Input methodologies review decisions – Topic paper 1 – Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016).

4 The definition of "price" for the purposes of Part 4 includes "individual prices, aggregate prices, or revenues". When setting a price-quality path, we must specify prices as either or both of prices or total revenues; Commerce Act 1986, ss 52C and 53M.

2.5 The updated draft revenue allowances we propose for each distributor in the first year of the DPP3 period are listed in Table 2.1 below, alongside the revenue allowances we proposed in our draft decision. Updated draft revenues over the whole DPP3 period are set out in Table 2.2.

Table 2.1 Updated draft net allowable revenues for 2020/21 ($m) [5]

Distributor	Allowable revenue in 2020/21 ($m)	Draft allowable revenue 2020/21 ($m)	Change ($m)	Change (%)
Alpine Energy	42.61	45.36	-2.75	-6.06%
Aurora Energy	73.18	72.03	1.15	1.59%
Centralines	9.21	9.40	-0.19	-2.02%
EA Networks	34.16	37.70	-3.53	-9.37%
Eastland Network	23.89	25.06	-1.16	-4.64%
Electricity Invercargill	12.18	12.29	-0.11	-0.87%
Horizon Energy	23.95	25.01	-1.06	-4.23%
Nelson Electricity	5.52	5.59	-0.07	-1.17%
Network Tasman	26.04	28.78	-2.74	-9.53%
Orion NZ	158.31	161.17	-2.86	-1.77%
OtagoNet	25.75	25.08	0.66	2.63%
The Lines Company	34.70	33.94	0.75	2.22%
Top Energy	38.23	42.19	-3.96	-9.38%
Unison Networks	100.07	102.25	-2.18	-2.14%
Vector Lines	393.42	403.35	-9.92	-2.46%
Industry total	**1,001.23**	**1,029.20**	**-27.97**	**-2.72%**

[5] Starting prices are expressed as maximum allowable revenue (MAR) in the first year of the DPP3 period, in nominal millions of dollars. Prices for Wellington Electricity and Powerco have not been included, as we do not propose setting starting prices for these distributors until their current CPPs end.

Table 2.2 Net allowable revenue in each year of the regulatory period ($m)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25	PV
Alpine Energy	42.61	43.44	44.32	45.21	46.11	197.47
Aurora Energy	73.18	81.24	90.27	100.27	111.37	403.39
Centralines	9.21	9.39	9.58	9.77	9.96	42.67
EA Networks	34.16	34.83	35.54	36.25	36.97	158.33
Eastland Network	23.89	24.36	24.85	25.35	25.86	110.73
Electricity Invercargill	12.18	12.42	12.67	12.93	13.19	56.47
Horizon Energy	23.95	24.42	24.91	25.41	25.92	110.99
Nelson Electricity	5.52	5.63	5.74	5.86	5.98	25.59
Network Tasman	26.04	26.54	27.08	27.62	28.18	120.66
Orion NZ	158.31	161.40	164.67	167.96	171.32	733.66
OtagoNet	25.75	26.25	26.78	27.31	27.86	119.31
The Lines Company	34.70	35.37	36.09	36.81	37.55	160.79
Top Energy	38.23	38.98	39.77	40.56	41.37	177.18
Unison Networks	100.07	102.02	104.09	106.17	108.29	463.74
Vector Lines	393.42	401.10	409.22	417.40	425.75	1,823.23

Changes in allowable revenue since the draft decision

2.6 In total for distributors on the DPP, proposed allowable revenues are lower overall than in our draft decision.[6] In the first year of the DPP3 regulatory period (2020/21), revenues are $28m or 2.7% lower than in the draft decision.

2.7 The main influences driving this 'draft to update' change are:

2.7.1 a lower WACC estimate (resulting in a -4.63% change in allowable revenue);

2.7.2 a lower opening regulatory asset base (RAB) for the 2019/20 year than was forecast in our draft decision (-1.76%);

2.7.3 an increase in capex allowances (+1.41%); and

2.7.4 and increase in opex allowances (+0.87%).

2.8 Other inputs to the financial model have lesser individual impacts, with a combined effect of increasing allowable revenues by 1.38%.

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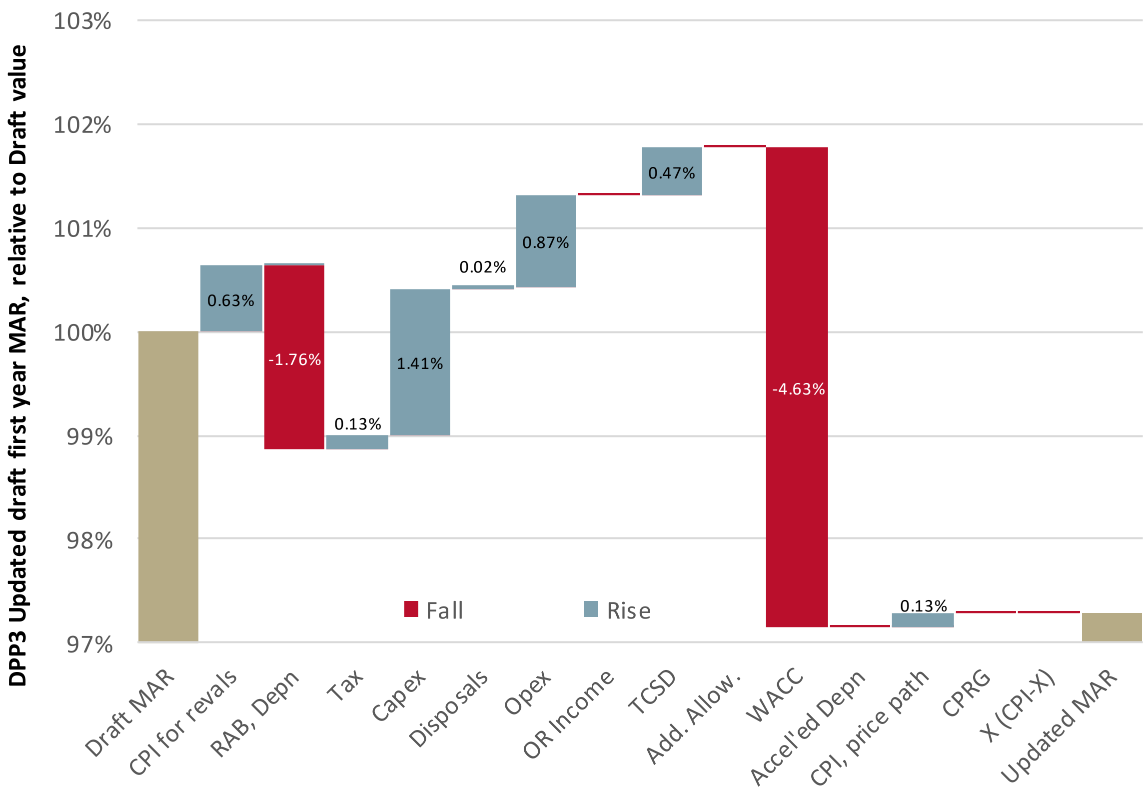
[6] Values calculated at "an industry-wide level" are from the summation of the values for 15 EDBs that will be subject to the DPP3 determination. These EDBs exclude Powerco and Wellington Electricity which will continue to be subject to their CPP determinations.

2.9 These drivers are presented in total for distributors on the DPP in Figure 2.1 below. Changes since the draft decision are not uniform across all distributors. In particular, changes in opex and capex allowances, and changes in the opening RAB for each distributor result in significant differences.

2.10 These changes are discussed in more detail in the following sections. A waterfall analysis of the changes for individual distributors can be found in in the "MAR Waterfall (draft to update)" model and the "MAR Waterfall (2015 to update)" model published alongside this paper.[7]

2.11 For businesses who see significant changes in allowable revenue (EA Networks, Network Tasman, and Top Energy) three factors – WACC, opex, and opening RAB – have all moved in the same direction (although in Network Tasman's case this is partially offset by an increase in capex).

Figure 2.1 Drivers of change in net allowable revenues since the draft decision for DPP distributors (axis truncated)



[7] These models are available on our website at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-price-quality-paths/electricity-lines-default-price-quality-path/2020-2025-default-price-quality-path

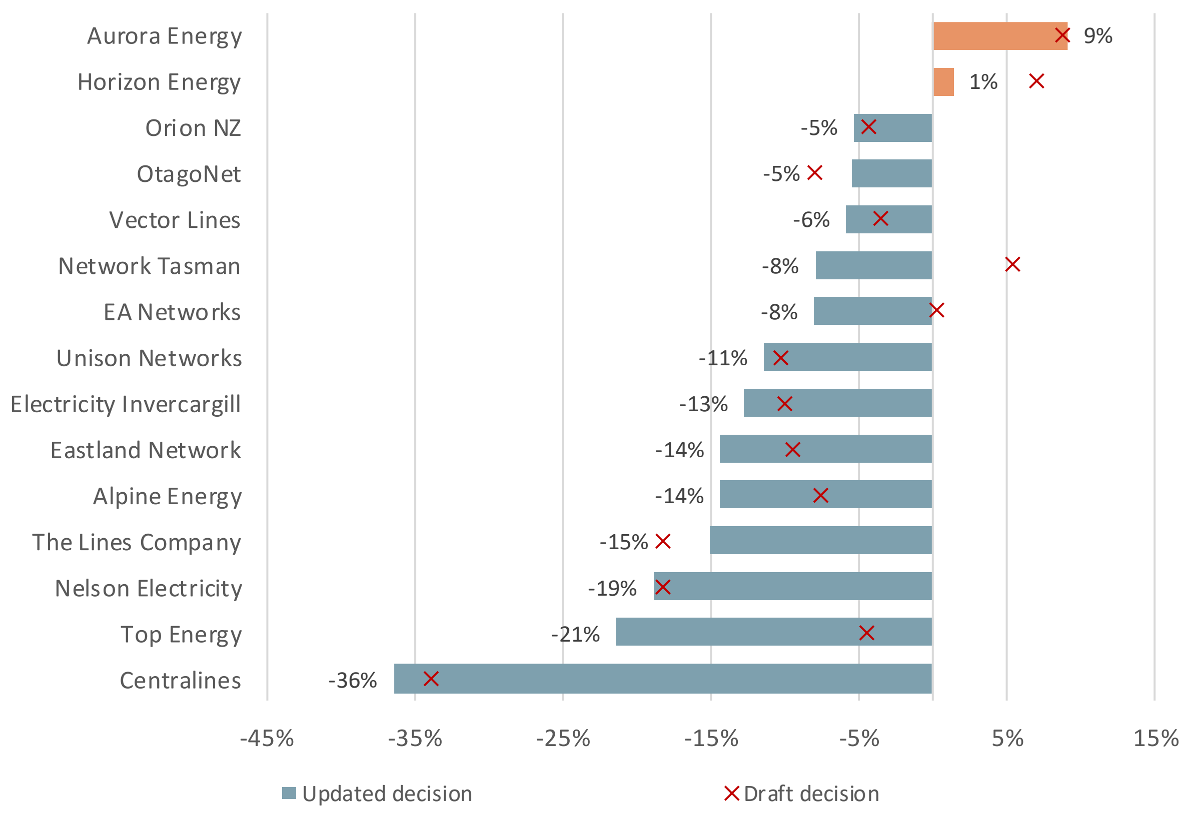
Changes in allowable revenue relative to DPP2 allowable revenue

2.12 We have set these updated draft DPP3 allowable revenues on the basis of the current and projected profitability of each distributor.[8] As a result of this approach, allowable revenues in 2020/21 (the first year of the DPP3 period) would change significantly relative to allowable revenues in 2019/20 (the final year of the DPP2 period).

2.13 The changes in allowable revenue between 2019/20 and 2020/21 for each distributor are set out in Figure 2.2 below. We have also included a comparison to the change in allowable revenue from the draft decision.

2.14 Note that this change in allowable revenue depends on an estimate of allowable revenue for 2019/20. This estimate was derived by projecting current allowable revenues (at the draft, for the 2017/18 year, for this update, the 2018/19 year) forward. The change in this estimate also affects the allowable revenue adjustment, and has had a particularly marked impact on Top Energy and Network Tasman.

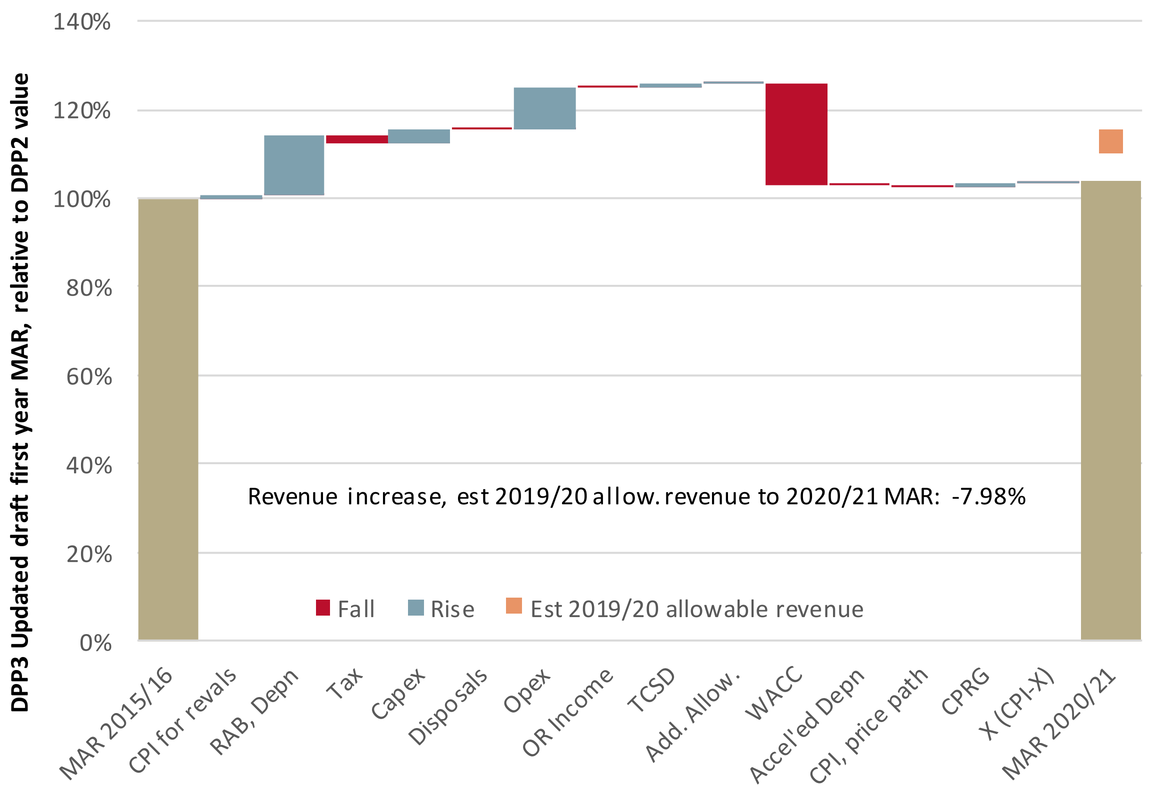
Figure 2.2 Change in allowable revenue 2019/20 to 2020/21 (%)



8 A fuller description of the 'building blocks' (BBAR) method we use can be found in: Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision – Reasons Paper" (29 May 2019), Chapter 5.

2.15 The factors that are driving this 'DPP2 to DPP3' change are set out in Figure 2.3, and are broadly the same set of factors present in the draft decision. The reduction in the WACC is the predominant driver of decreases in allowable revenues, partially offset by an increase in RAB over the DPP2 period and an increase in opex relative to 2013/14 base year levels.

Figure 2.3 Divers of change in allowable revenue for DPP distributors – relative to DPP2 (2016) allowances[9]



Factors that could change between now and the final decision

2.16 The revenue allowances we present in this paper are not the final allowances for DPP3. Key factors that could change include:

2.16.1 policy decisions about our approach to setting opex and capex allowances (discussed further below) and any other inputs to the financial model not determined by the IMs; and

2.16.2 resolution of any errors in the data we have used in determining allowable revenues.

9 Note that this excludes Orion NZ as well as Powerco and Wellington Electricity. As there is no DPP2 model for Orion NZ, we have no point of comparison to reconcile to.

Proposed opex allowances

2.17 To determine allowable revenues and for the purposes of the incremental rolling incentive scheme (IRIS) efficiency incentive, we forecast each distributor's operating expenditure allowances using a 'base-step-trend' approach. Updated draft opex allowances for each distributor are set out in Table 2.3 below.

Table 2.3 Updated draft opex allowances ($m)

Distributor	Updated total opex allowance	Draft total opex allowance	Change ($m)	Change (%)
Alpine Energy	102.89	100.51	2.38	2.37%
Aurora Energy	245.35	216.50	28.85	13.33%
Centralines	21.65	19.67	1.99	10.11%
EA Networks	67.81	72.29	-4.48	-6.20%
Eastland Network	55.87	57.14	-1.27	-2.23%
Electricity Invercargill	27.22	26.22	0.99	3.79%
Horizon Energy	52.71	59.44	-6.73	-11.32%
Nelson Electricity	12.09	11.27	0.82	7.27%
Network Tasman	59.13	64.16	-5.03	-7.83%
Orion NZ	343.54	327.43	16.10	4.92%
OtagoNet	48.23	42.19	6.03	14.30%
The Lines Company	78.45	70.37	8.08	11.48%
Top Energy	86.31	93.52	-7.21	-7.71%
Unison Networks	221.76	225.81	-4.05	-1.79%
Vector Lines	707.89	693.18	14.71	2.12%
Wellington Electricity	191.47	195.31	-3.84	-1.97%
Industry total	**2,322.37**	**2,275.01**	**47.36**	**2.08%**

2.18 Updated draft opex allowances over the DPP3 period as a whole are set out in Table 2.4 below.

Table 2.4 Updated draft opex allowances over DPP3 ($m, nominal)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	19.42	19.98	20.57	21.17	21.75
Aurora Energy	45.87	47.43	49.08	50.70	52.27
Centralines	4.18	4.25	4.33	4.41	4.48
EA Networks	12.72	13.13	13.55	13.99	14.41
Eastland Network	10.62	10.89	11.17	11.46	11.73
Electricity Invercargill	5.19	5.31	5.44	5.57	5.70
Horizon Energy	10.00	10.26	10.54	10.82	11.08
Nelson Electricity	2.28	2.35	2.42	2.49	2.56
Network Tasman	11.16	11.48	11.82	12.17	12.50
Orion NZ	64.12	66.38	68.74	71.04	73.27
OtagoNet	9.15	9.40	9.65	9.90	10.13
The Lines Company	14.93	15.31	15.70	16.08	16.43
Top Energy	16.32	16.78	17.26	17.74	18.20
Unison Networks	41.85	43.07	44.34	45.64	46.87
Vector Lines	131.56	136.48	141.62	146.67	151.56
Wellington Electricity	n/a	37.19	38.29	39.40	40.46

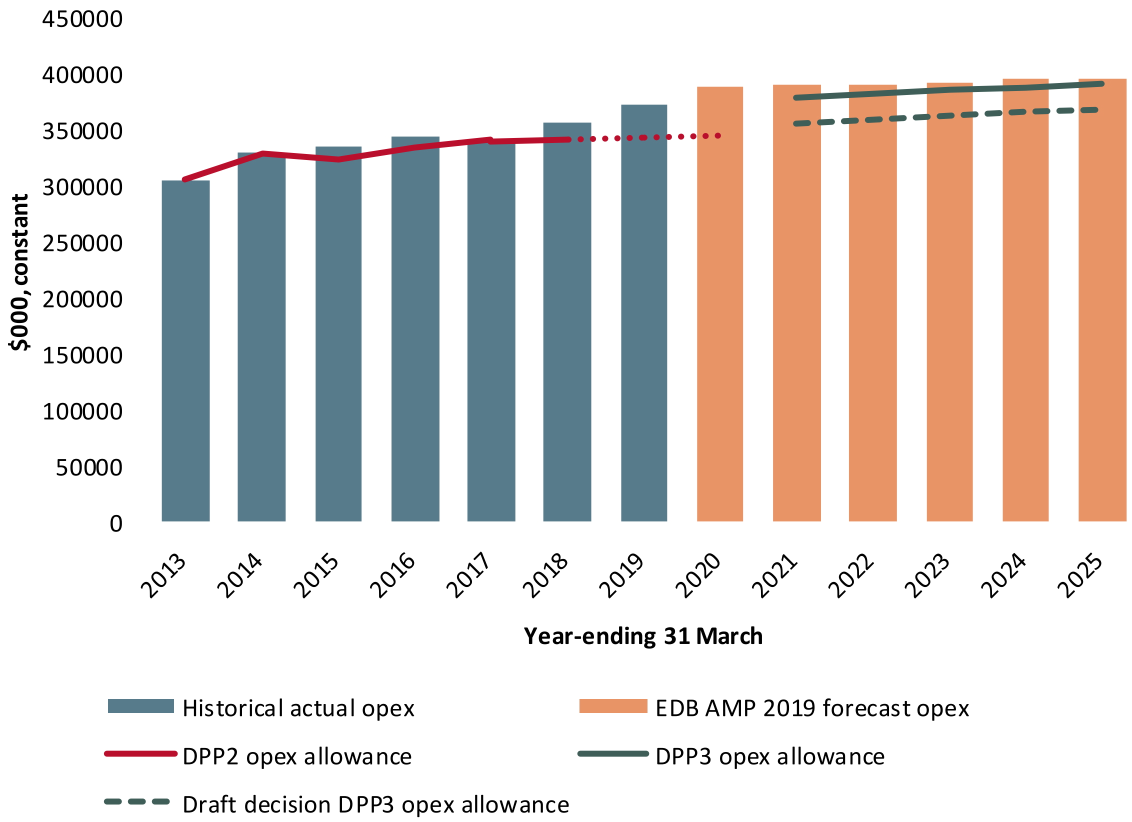
Changes in opex allowances compared to the draft decision

2.19 At an industry-wide level, opex allowances are 2.1% higher than those we proposed in the draft decision. The main changes since the draft that affect opex allowances are that we use 2019 ID disclosures to calculate the circuit length growth rate and for the base year. We also use an updated release of NZIER's forecasts of LCI (labour cost index) and PPI (produce price index) inflation. See Attachment A for a summary of these changes.

2.20 Figure 2.4 compares (in constant price terms) updated draft opex allowances at an industry level to historic levels of opex, the draft decision allowances, and distributors 2019 asset management plans (AMPs) forecasts. In general, updated draft opex allowances are now broadly in line with distributors' forecasts in their 2019 AMPs.

2.21 Changes in other key parameters in our opex forecasts, such as scale growth and input cost trend factors have not had a material impact on changes in updated draft opex allowance.

Figure 2.4 Industry-wide opex series ($000)



Changes in base year opex are offset by IRIS adjustments

2.22 It is worth noting that while increases or decreases in the opex base year affect the net allowable revenue we determine at the start of the DPP period, due to the IRIS mechanism (specifically the base year adjustment term), they will have a reduced impact on the gross allowable revenue distributors can recover over the DPP3 period. Any increase or decrease in opex in the base year will be shared between consumers and distributors at the opex retention rate.

Updated opex parameters for individual distributors

2.23 The changes discussed above do not impact all distributors' opex allowances in the same way, as key inputs depend on data from individual ID disclosures. Total opex base varies due to differing levels of actual opex in 2019 and, the aggregate trend varies due to different levels of population and circuit length growth. The updated parameters of our opex approach for each distributor are set out in Table 2.5.

2.24 Significant increases for individual distributors include:

2.24.1 Aurora Energy (13% increase) has seen a sharp increase in their opex base costs, and a moderate increase in circuit length growth. In large part, this base increase is driven by CPP preparation costs and Aurora's ongoing investment programme.

2.24.2 Centralines (10% increase) now see a less negative trend in circuit length growth, which has a material impact on DPP3 allowances. This is combined with a higher base year.

2.24.3 OtagoNet (14% increase) have an increase that is again driven by an increase in base year opex.

2.24.4 The Lines Company (11% increase) have a significant increase in their base year, but this is partially offset by a lower trend in circuit length growth.

2.25 Only Horizon Energy have seen a significant (-11%) negative change. This is primarily driven by a drop in base year opex, partially offset by higher circuit length growth.

Table 2.5 Updated opex parameters for each distributor

Distributor	Total opex base	Step factors	Aggregate trend 2019-2023 (CAGR, %)	Aggregate trend 2023-2025 (CAGR, %)
Alpine Energy	18.30	0.00	2.97%	2.83%
Aurora Energy	42.77	0.00	3.50%	3.21%
Centralines	4.02	0.00	1.89%	1.67%
EA Networks	11.91	0.00	3.28%	3.13%
Eastland Network	10.08	0.00	2.61%	2.45%
Electricity Invercargill	4.94	0.00	2.46%	2.33%
Horizon Energy	9.47	0.00	2.72%	2.55%
Nelson Electricity	2.15	0.00	3.03%	2.83%
Network Tasman	10.50	0.00	3.00%	2.82%
Orion NZ	59.68	0.00	3.60%	3.24%
OtagoNet	8.66	0.00	2.75%	2.43%
The Lines Company	14.17	0.00	2.60%	2.28%
Top Energy	15.41	0.00	2.87%	2.70%
Unison Networks	39.41	0.00	2.99%	2.81%
Vector Lines	121.96	0.00	3.81%	3.45%
Wellington Electricity	34.02	0.00	3.00%	2.80%

Opex factors that could change between now and the final decision

2.26 The updated draft opex allowances and the parameters used to determine them are not the final allowances we propose. While they have been updated for the most recent data available, changes in policy decisions could have a significant impact on the final decision.

2.27 These changes may include:

2.27.1 our approach to partial productivity;

2.27.2 the forecasts of input cost inflation we use;

2.27.3 inclusion of any 'non-scale' step changes;

2.27.4 our econometric model of scale growth; or

2.27.5 the removal of operating lease costs which are now capitalised.

2.28 We also intend to remove Fire and Emergency New Zealand (FENZ) levies and pecuniary penalties from the base year, as proposed in our draft decision (assuming this decision is retained for the final).

2.29 Finally, we may make changes to resolve any identified errors in the input data our opex forecasts rely on.

Proposed capex allowances

2.30 To determine allowable revenues and for the purposes of the IRIS efficiency incentive, we forecast each distributor's capex allowances by applying a series of scrutiny tests to each distributor's AMP forecasts.

2.31 Updated draft capex allowances for each distributor are set out in Table 2.6 below, with a comparison to the allowances we proposed in our draft decision.

Table 2.6 Updated draft capex allowances ($m)

Distributor	Updated capex allowance	Draft capex allowance	Change ($m)	Change (%)
Alpine Energy	77.84	71.70	6.14	8.56%
Aurora Energy	191.42	147.99	43.43	29.34%
Centralines	17.17	14.76	2.40	16.29%
EA Networks	84.90	88.48	-3.58	-4.05%
Eastland Network	43.69	40.90	2.79	6.81%
Electricity Invercargill	23.37	20.80	2.56	12.32%
Horizon Energy	40.03	36.84	3.19	8.65%
Nelson Electricity	8.19	8.27	-0.09	-1.04%
Network Tasman	36.25	27.68	8.57	30.97%
Orion NZ	389.95	340.15	49.79	14.64%
OtagoNet	82.35	79.82	2.53	3.17%
The Lines Company	82.86	60.35	22.51	37.30%
Top Energy	79.53	90.26	-10.73	-11.89%
Unison Networks	244.68	232.94	11.73	5.04%
Vector Lines	1,078.70	953.59	125.12	13.12%
Wellington Electricity	172.68	181.52	-8.84	-4.87%

Industry total	2,653.60	2,396.08	257.52	10.75%

2.32 Updated draft capex allowances over the DPP3 period as a whole are set out in Table 2.7.

Table 2.7 Updated draft capex allowances over the DPP3 period ($m, nominal)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	16.66	16.98	15.38	14.67	14.15
Aurora Energy	39.69	42.89	40.75	31.75	36.33
Centralines	5.11	2.64	3.88	2.72	2.81
EA Networks	18.17	18.07	17.95	15.85	14.86
Eastland Network	8.76	9.21	8.09	8.46	9.17
Electricity Invercargill	4.21	4.37	4.79	5.35	4.65
Horizon Energy	8.15	6.70	8.11	8.54	8.53
Nelson Electricity	1.55	1.63	1.66	1.67	1.67
Network Tasman	7.76	8.34	6.68	7.19	6.28
Orion NZ	72.17	63.78	89.62	79.93	84.44
OtagoNet	14.20	14.12	17.68	21.82	14.53
The Lines Company	18.31	16.91	15.86	16.54	15.24
Top Energy	14.64	15.17	16.62	16.38	16.72
Unison Networks	46.74	52.52	50.53	46.85	48.04
Vector Lines	218.22	217.47	221.44	217.38	204.20
Wellington Electricity	n/a	31.59	33.88	35.09	37.88

Changes in capex allowances since the draft decision

2.33 Overall, capex allowances have increased by 10.7% from the draft decision.

2.34 The most significant change affecting capex allowances is the use of distributors' 2019 AMP forecasts, which feature capex forecasts that are 12% higher in aggregate than the 2018 AMP forecasts used in the draft decision.

2.35 Additionally, the inclusion of actual ID data for the year ending 31 March 2019 in the historical reference period has changed the baselines we use as part of our scrutiny framework. Actual expenditure in 2019 was 12% higher than in 2018, and 29% higher than the 2013-2018 average in nominal terms across all relevant distributors.

Significant changes for individual distributors

2.36 In terms of distributors who have seen a significant change in their capex forecasts:

2.36.1 The Lines Company (37% increase) is a result of passing the historic forecast accuracy test with the addition on 2019 actual ID data;

2.36.2 Aurora Energy (29% increase) is partly due to the addition of 2019 actual expenditure to the historic reference dataset, and partly due to our updated approach to system growth.

2.37 Only Top Energy has seen a significant decrease in their capex allowance (-12%). This reflects changes between its 2018 and 2019 AMP forecasts. These changes appear to be a result of expenditure being brought forward from 2020/21 to 2019/20.

Impact of our updated approach to system growth

2.38 As discussed in Chapter 4, we have proposed changing our approach to scrutinising system growth capex. The revised approach has been incorporated into the updated models, which show that:

2.38.1 Twelve distributors fail one of the two tests that we now propose to use to scrutinise system growth capex. No distributors fail both tests.

2.38.2 Four of these distributors are forecasting increases in system growth capex (when considered net of capital contributions), and hence see their expenditure scaled back to their historic average. These are Network Tasman, OtagoNet, Vector and Wellington Electricity.

2.38.3 Of these four distributors, three (Network Tasman, OtagoNet and Wellington Electricity) are forecasting to more than double their system growth capex compared to their historic expenditure.

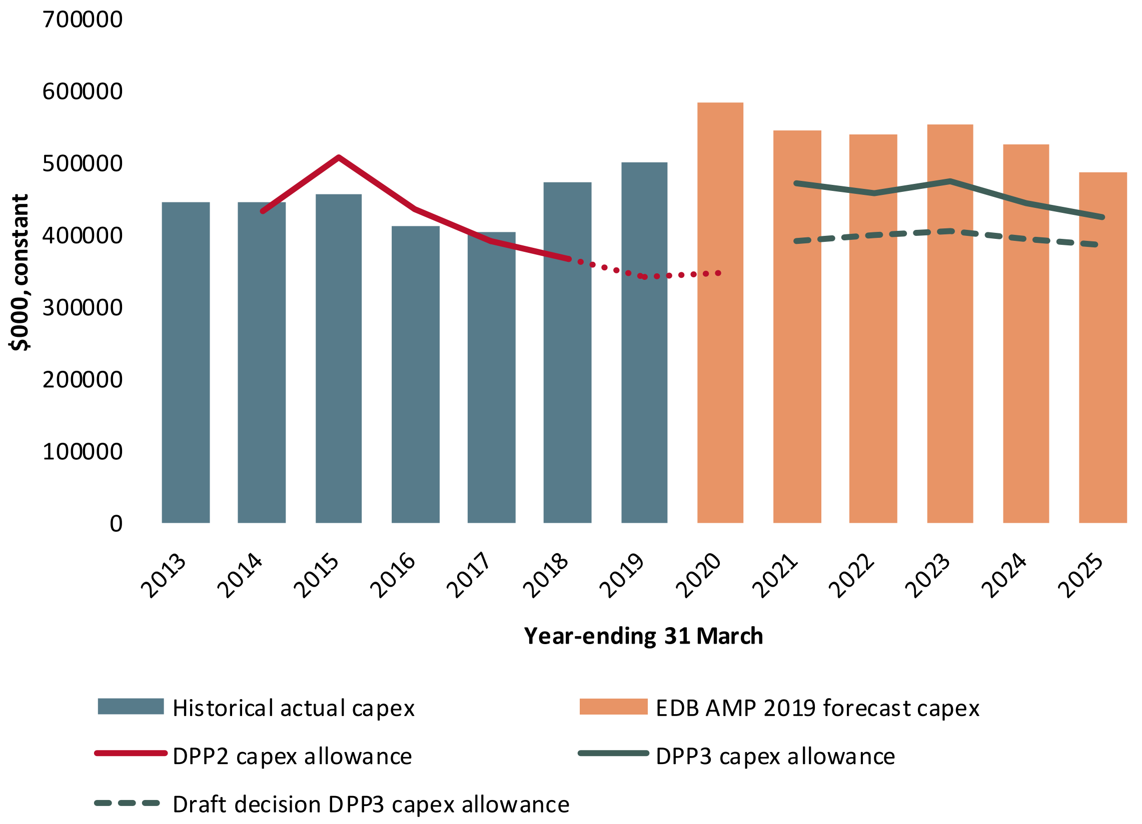
2.38.4 One distributor (Aurora Energy) would have had its system growth capex scaled back under the approach to scrutinising system growth that was included in the draft decision, but does not under the revised proposal.

2.39 We note that these results should be considered in the context of other changes we may make to how we set capex forecasts in our final decision, having considered all the feedback from submitters.

2.40 Finally, we have updated the capital goods price index (CGPI) forecast we use to project input cost inflation. This affects allowable revenues across the period by +0.3%.

2.41 Figure 2.5 compares our updated draft capex allowances at an industry level to historic levels of capex, the draft decision allowances, and distributors 2019 AMP forecasts.

Figure 2.5 Industry-wide capex time series (2019 constant $000)



Capex acceptance rates for individual distributors

2.42 The use of updated ID and AMP data does not impact all distributors in the same way. Our overall capex forecasts as a percentage of distributors' 2019 AMP forecasts are presented in Figure 2.6 below.

2.43 Acceptance rates at a category level are set out in Table 2.8. Note that these rates are presented net of capital contributions.

Figure 2.6 Capex acceptance rates

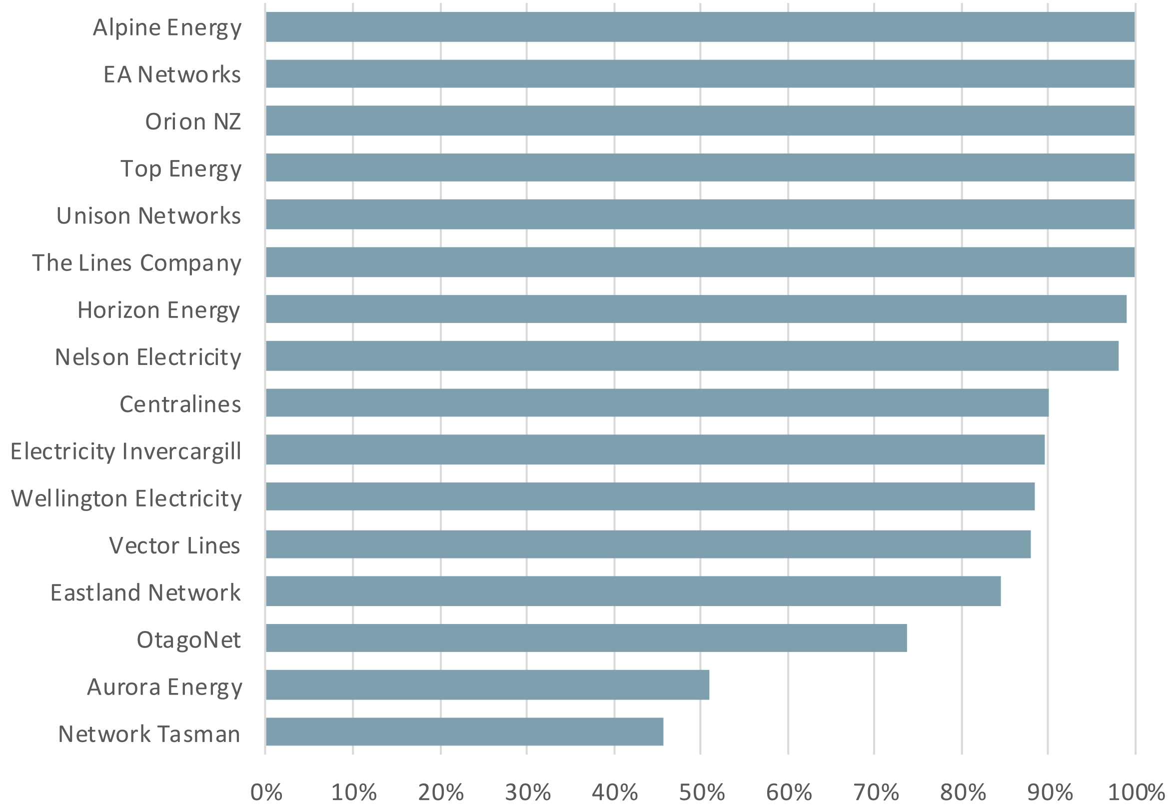


Table 2.8 Capex acceptance rate by category

Distributor	Total capex	Asset replacement & renewal	Consumer connections	System growth	Reliability, safety and environment	Other capex
Alpine Energy	100%	100%	100%	100%	100%	100%
Aurora Energy	51%	41%	100%	100%	100%	23%
Centralines	90%	100%	100%	100%	100%	68%
EA Networks	100%	100%	100%	100%	100%	100%
Eastland Network	85%	81%	100%	100%	86%	79%
Electricity Invercargill	90%	100%	30%	100%	100%	100%
Horizon Energy	99%	100%	100%	100%	100%	73%
Nelson Electricity	98%	100%	17%	100%	100%	100%
Network Tasman	46%	50%	100%	24%	100%	87%
Orion NZ	100%	100%	100%	100%	100%	100%
OtagoNet	74%	100%	55%	40%	100%	55%
The Lines Company	100%	100%	100%	100%	100%	98%
Top Energy	100%	100%	100%	100%	100%	100%
Unison Networks	100%	100%	100%	100%	100%	100%
Vector Lines	88%	100%	100%	96%	100%	77%
Wellington Electricity	88%	100%	100%	42%	100%	100%

Distributors with significant declined capex

2.44 Network Tasman still failed the historic accuracy test, which resulted in scaling back across most categories. We note that we are considering whether to retain this test as part of the final decision.

2.45 Aurora Energy have again seen their very substantial increase in asset replacement and renewal capex scaled back to historic levels. We anticipate further assessment of this capex as part of Aurora's CPP application.

2.46 OtagoNet's consumer connection capex has been scaled back because of the test relating to forecast increase in ICP numbers. As we have proposed applying this test to system growth (see Chapter 4), this now affects system growth as well.

Capex factors that could change between now and the final decision

2.47 As with our forecasts of operating expenditure, these updated draft capex forecasts do not represent the final allowances we propose. While they have been updated for the most recent data available, changes in policy decisions could have a significant impact. These changes may include:

2.47.1 changes to our approach to system growth based on submissions on this paper;

2.47.2 the scrutiny tests we apply to other sub-categories of expenditure, and at a category level; and

2.47.3 the 'fall-back' forecasts we use where a test is failed.

2.48 We may also make changes to resolve any identified errors in the input data our capex forecasts rely on.

Other inputs to the financial model

2.49 Forecasts of operating and capital expenditure are the main issues we must make decisions about when determining allowable revenue in a DPP. However, there are several other factors which can have a significant impact on allowable revenues. These include:

2.49.1 the WACC estimate;

2.49.2 forecasts of CPI; and

2.49.3 the initial conditions for the base year.

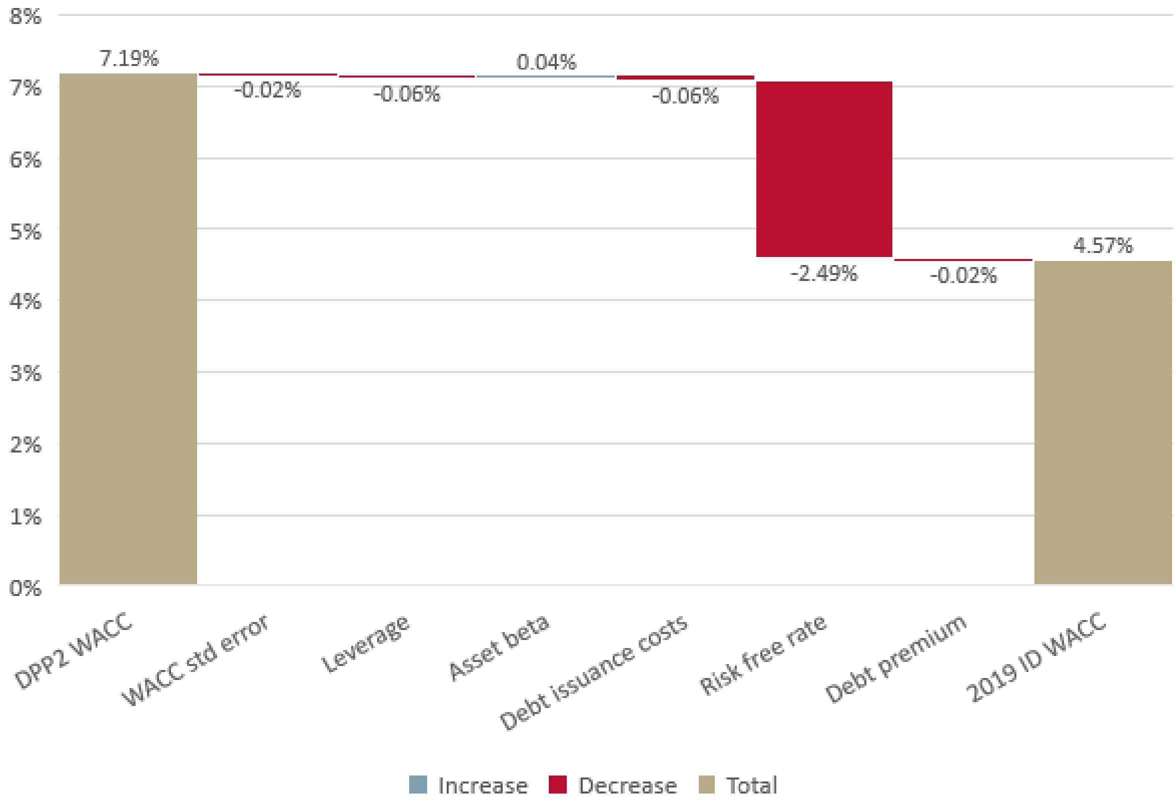
2.50 These parameters have all changed since the draft decision. This section discussed the impact of each of these factors.

WACC estimate

2.51 For the draft decision, we used the 2019 estimate of vanilla WACC determined for ID purposes to when setting proposed allowable revenue; a rate of 5.13%. For this update, we have used the final vanilla WACC estimate; a rate of 4.57%.

2.52 As shown in Figure 2.7 below sets out the drivers of change from the DPP2 WACC of 7.19%. Almost all of this change is accounted for by changes in the risk-free rate (-2.49%) with -0.55% of that change occurring since the WACC used in the draft decision was determined.

Figure 2.7 Drivers of change in WACC (relative to DPP2)



Forecasts of CPI

2.53 We have updated the forecasts of CPI we have used so that they are consistent with the forecast WACC, as required by the IMs. We forecast CPI for two purposes:

2.53.1 to calculate the rate at which assets are revalued (which uses a 31 March year-end growth rate); and

2.53.2 as an element of the price path when forecasting how revenue will grow over the DPP3 period (which uses an average of four quarters' growth rate).

2.54 CPI forecasts for revaluations and as an element in the price path are set out in Table 2.9 below.

Table 2.9 CPI forecasts

Pricing year ending	Updated CPI used for revaluations	Updated CPI for the price path	Draft CPI used for revaluations	Draft CPI for the price path
31 March 2019	1.48%	1.69%	1.60%	1.72%
31 March 2020	1.70%	1.52%	1.70%	1.45%
31 March 2021	1.90%	1.75%	2.10%	1.98%
31 March 2022	2.00%	1.95%	2.10%	2.07%
31 March 2023	2.00%	2.02%	2.07%	2.07%
31 March 2024	2.00%	2.00%	2.03%	2.03%
31 March 2025	2.00%	2.00%	2.00%	2.00%

Closing RAB for the base year

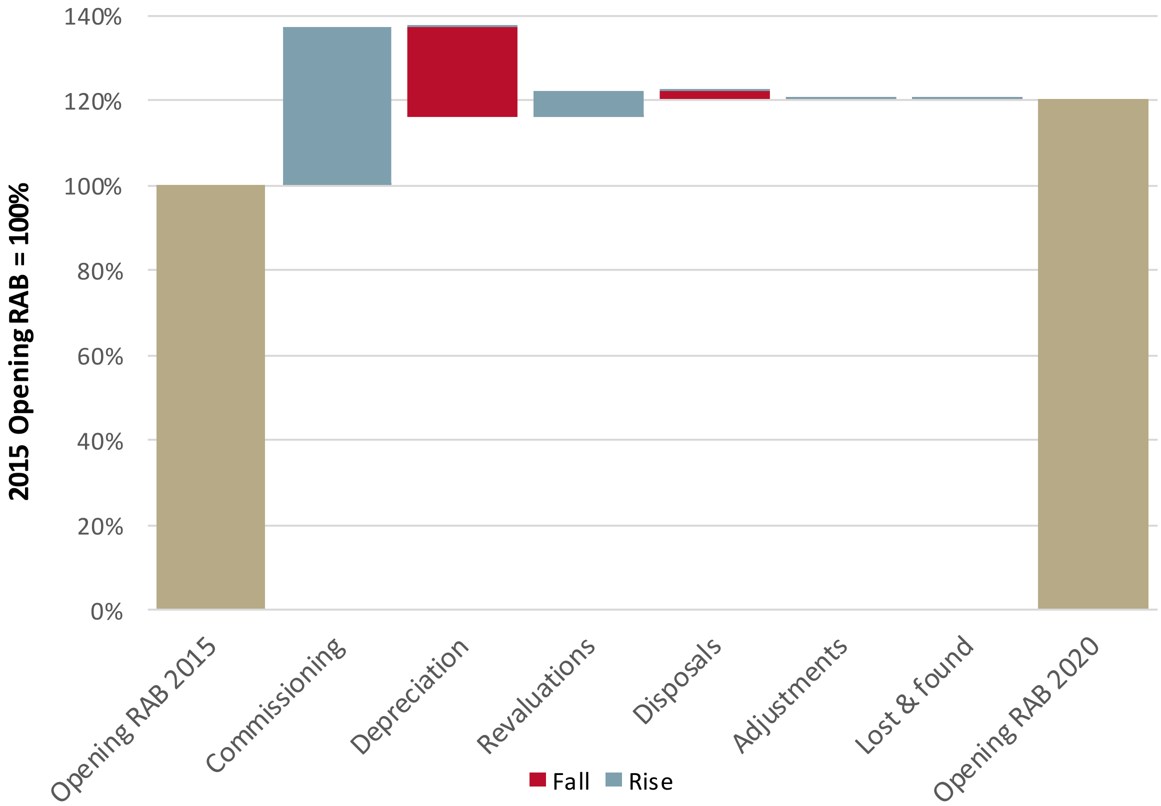
2.55 The financial model we use to set the DPP depends on a set of 'initial conditions' for the base year. These are taken from distributors' ID disclosures, and have been updated for 2019 data.

2.56 Of the various inputs, the only significant driver of change is the closing RAB value. Overall, differences between the forecasts we used at the draft and the actual data we now have available have caused a -1.76% decrease in allowable revenue.

2.57 For all distributors, this is partly due to CPI for the year ending 2019 being lower than forecast (1.48% versus 1.60%), leading to a lower level of revaluations. For specific distributors, the overall impact varies based on distributors commissioning more or less assets than forecast in 2019.

2.58 The overall impact of the roll-forward of the RAB from the RAB used to set prices for DPP2 is set out in Figure 2.8.

Figure 2.8 Roll-forward of RAB from 2015 to 2020



Chapter 3 Updated draft quality standards and incentives

Purpose of this chapter

3.1 This chapter explains the impact updated section 53ZD data (disclosed 15 August 2019) has had on the quality standards and incentives we propose for DPP3.

3.2 It is important to note at the outset that due to difficulties some distributors have faced when applying the current definition of SAIFI, the data used in this update has not generally been subject to audit, and may change significantly following the disclosure of final section 53ZD data in October 2019.

Factors influencing all quality parameters

3.3 Most changes in the quality parameters set out below are due to an updated reference period which removes the 2009 disclosure year and adds the 2019 disclosure year.

3.4 Horizon Energy has seen significant changes in its quality parameters. This is due to the purchase of the Te Kaha spur asset from Transpower in 2018, that is included in Horizon's 2019 dataset, but that was not included in the 2018 dataset, as this was prior to the purchase.

3.5 Powerco specifically has seen significant changes across all the parameters discussed in this chapter, as its updated section 53ZD response provided significant revisions to its interruption dataset.[10]

Updated draft major event boundary values

3.6 Our approach to normalisation underpins both quality unplanned standards and incentive parameters. Updated draft unplanned SAIDI and SAIFI boundary values for each distributor are set out in Table 3.1.

3.7 We have made a correction to the boundary values of Electricity Invercargill and Nelson Electricity to accurately reflect the policy intent of the reduced frequency of major events for small networks (as outlined in paragraphs K57 to K61 of the draft reasons paper). This has a flow-on impact for the unplanned standards and incentives outlined below.

[10] Powerco provided a 'normalised' dataset in December 2018 which was used for the draft decision. It provided a 'non-normalised' or raw interruption dataset in August 2019.

Table 3.1 Major event boundary values

Distributor	SAIDI boundary	SAIFI boundary
Alpine Energy	9.25	0.0605
Aurora Energy	4.49	0.0567
Centralines	6.45	0.0985
EA Networks	5.82	0.0680
Eastland Network	14.08	0.2135
Electricity Invercargill	3.68	0.0782
Horizon Energy	13.01	0.0841
Nelson Electricity	6.79	0.1410
Network Tasman	6.82	0.0667
Orion NZ	6.79	0.0601
OtagoNet	9.61	0.1365
Powerco	6.47	0.0373
The Lines Company	8.96	0.1340
Top Energy	25.09	0.1920
Unison Networks	6.30	0.0679
Vector Lines	4.25	0.0259
Wellington Electricity	1.75	0.0292

Updated draft quality standards

3.8 This section sets out and briefly explains our updated draft quality standards. The standards for each distributor are set out in Table 3.2. Significant changes in each standard for specific distributors are then discussed in the remainder of this section.

Unplanned standards

3.9 Three distributors have seen significant changes in unplanned SAIDI and SAIFI standards:

3.9.1 Nelson Electricity and Electricity Invercargill, due to an error with the way boundary values were calculated in the draft decision; and

3.9.2 Powerco, due to significant revisions in its section 53ZD data.

Table 3.2 Updated draft quality standards

Distributor	Unplanned SAIDI (1-year)	Unplanned SAIFI (1-year)	Planned SAIDI (5-year)	Planned SAIFI (5-year)	Extreme outage SAIDI
Alpine Energy	128.60	1.2055	822.99	3.4862	27.74
Aurora Energy	81.26	1.3802	974.24	5.6431	13.48
Centralines	83.76	3.2538	542.07	2.7087	19.35
EA Networks	96.52	1.2906	1376.08	4.8939	17.46
Eastland Network	246.38	3.3119	1353.62	7.6071	42.25
Electricity Invercargill	26.76	0.7100	114.49	0.5183	11.03
Horizon Energy	192.35	2.3549	858.63	5.4415	39.04
Nelson Electricity	24.80	0.5276	180.11	2.3664	20.38
Network Tasman	100.13	1.2079	1129.14	4.9021	20.46
Orion NZ	90.40	1.0037	198.40	0.7481	20.38
OtagoNet	163.52	2.2529	2107.24	9.5537	28.82
Powerco	181.41	2.2257	773.45	4.1504	19.40
The Lines Company	184.96	3.1741	1343.40	8.7544	26.87
Top Energy	402.12	5.1596	1905.36	7.7526	75.28
Unison Networks	88.79	1.8240	630.63	4.4111	18.91
Vector Lines	104.84	1.3261	585.38	2.8783	12.75
Wellington Electricity	40.11	0.6180	69.70	0.5536	5.24

3.10 We have made an adjustment to the way we cap the inter-regulatory period change for unplanned reliability to better reflect the 5% limit in increases and decreases of parameters between regulatory periods (as outlined in paragraphs J27 to J38 of the draft reasons paper).[11] The impact of this amendment results in an minor increase to the limits for all those distributors impacted.

Planned standards

3.11 As some distributors have seen significant increases in planned interruptions over the last ten years, the addition of 2019 data and the removal of 2009 data from the reference period has had a significant impact on their planned standards.

3.12 Distributors affected by this include Powerco, Aurora Energy, Vector Lines and Wellington Electricity.

[11] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision – Reasons Paper" (29 May 2019).

3.13 As noted above, Horizon's standard has increased by 60% largely due to the Te Kaha spur asset purchase.

Extreme SAIDI standard

3.14 In our draft decision, we linked the extreme SAIDI standard to the major event boundary value. As boundary values for some distributors have shifted materially, this has had a flow-on impact to extreme event SAIDI standards. This change affects Powerco, Electricity Invercargill, and Nelson Electricity.

Updated draft quality incentive parameters

3.15 The updated draft quality incentive scheme parameters for each distributor are set out in Table 3.3 on the following page.

Changes in targets and caps

3.16 As targets and caps are – in the draft decision – linked to the unplanned and planned SAIDI standards, changes (discussed above) in these standards have an impact on these parameters.

No change in collars

3.17 As the proposed collar for all distributors was set at zero, no distributors have seen a change in their proposed collar.

Changes in incentive rates

3.18 As incentive rates are determined with reference to the value of lost load (VoLL), distributors have seen only modest changes in incentive rates due to updated 53ZD data. However, as the VoLL is reduced in line with the IRIS retention factor, the change in the WACC (which has reduced the retention factor from 26% to 23%) has led to an approximate 10% reduction in the incentive rate across all distributors.

3.19 Only EA Networks materially deviates from this 10% change, due to a relatively large decrease in the quantity of electricity delivered in their 2019 ID data, which is used to convert the per-MWh VoLL figure into a per-SAIDI minute figure.

Table 3.3 Quality incentive scheme parameters

Unplanned SAIDI (mins)	Unplanned collar	Unplanned target	Unplanned cap	Incentive rate ($/min)	Maximum loss (%)	Maximum gain (%)
Alpine Energy	0.00	104.39	128.60	7,004	0.38%	1.65%
Aurora Energy	0.00	70.50	81.26	11,694	0.14%	0.90%
Centralines	0.00	65.92	83.76	952	0.18%	0.65%
EA Networks	0.00	81.26	96.52	4,795	0.21%	1.10%
Eastland Network	0.00	209.79	246.38	2,486	0.37%	2.10%
Electricity Invercargill	0.00	18.07	26.76	2,262	0.16%	0.32%
Horizon Energy	0.00	155.79	192.35	4,797	0.70%	3.00%
Nelson Electricity	0.00	13.27	24.80	1,260	0.25%	0.29%
Network Tasman	0.00	81.07	100.13	5,564	0.39%	1.67%
Orion NZ	0.00	77.84	90.40	28,165	0.21%	1.33%
OtagoNet	0.00	134.69	163.52	3,857	0.42%	1.94%
Powerco	0.00	166.62	181.41	42,585	0.21%	2.39%
The Lines Company	0.00	158.93	184.96	3,402	0.25%	1.50%
Top Energy	0.00	343.70	402.12	2,918	0.43%	2.52%
Unison Networks	0.00	77.67	88.79	14,387	0.15%	1.07%
Vector Lines	0.00	96.49	104.84	75,128	0.15%	1.77%
Wellington Electricity	0.00	34.01	40.11	20,635	0.13%	0.74%
Planned SAIDI (mins)	**Planned collar**	**Planned target**	**Planned cap**	**Incentive rate ($/min)**	**Maximum loss (%)**	**Maximum gain (%)**
Alpine Energy	0.00	54.87	164.60	3,502	1.30%	0.43%
Aurora Energy	0.00	64.95	194.85	5,847	1.25%	0.42%
Centralines	0.00	36.14	108.41	476	0.54%	0.18%
EA Networks	0.00	91.74	275.22	2,397	1.86%	0.62%
Eastland Network	0.00	90.24	270.72	1,243	1.35%	0.45%
Electricity Invercargill	0.00	7.63	22.90	1,131	0.20%	0.07%
Horizon Energy	0.00	57.24	171.73	2,398	1.65%	0.55%
Nelson Electricity	0.00	12.01	36.02	630	0.39%	0.13%
Network Tasman	0.00	75.28	225.83	2,782	2.32%	0.77%
Orion NZ	0.00	13.23	39.68	14,083	0.34%	0.11%
OtagoNet	0.00	140.48	421.45	1,928	3.03%	1.01%
Powerco	0.00	51.56	154.69	21,293	1.11%	0.37%
The Lines Company	0.00	89.56	268.68	1,701	1.27%	0.42%
Top Energy	0.00	127.02	381.07	1,459	1.40%	0.47%
Unison Networks	0.00	42.04	126.13	7,193	0.87%	0.29%
Vector Lines	0.00	39.03	117.08	37,564	1.07%	0.36%
Wellington Electricity	0.00	4.65	13.94	10,318	0.15%	0.05%

Chapter 4 Proposed changes to system growth capex

Purpose of this chapter

4.1 In our draft decision we proposed using the forecasts within distributors' AMPs as the starting point for setting capex allowances. However, we proposed using a series of tests to assess the reasonableness of the forecasts. This included a potential approach to scrutinising system growth expenditure.

4.2 We received useful feedback from submitters on the approach to scrutinising system growth expenditure. Having considered the feedback, we are now proposing a different approach, whereby we would treat system growth expenditure together with consumer connections expenditure. We are seeking feedback on this proposal.

4.3 Submitters provided feedback on several other aspects of our draft decisions regarding capex allowances – including some that will interact with our revised proposal for scrutinising system growth. We are still considering all the feedback we received, which will be reflected in our final decision.

4.4 Any changes likely to come out of that consideration have been reasonably signalled by the draft decision or were contemplated by submitters and cross-submitters. Therefore, we are not seeking further feedback on any other aspects of our approach to setting capex forecasts.

Submitters identified issues with the approach to scrutinising system growth expenditure that was included in the draft decision

4.5 The test of system growth expenditure that we outlined in the draft decision utilised the supporting information in Schedule 12(b) of AMPs. It sought to identify whether each distributor's forecast expenditure for zone substations for system growth implied cost increases for additional zone substation capacity of more than 20%. However, we were not confident of the results of the test, and sought stakeholder input as to whether the test would identify inconsistencies in forecast system growth expenditure, or was affected by flawed assumptions and/or inadequacies in the Schedule 12(b) data. We also sought suggestions of other ways we could assess system growth expenditure.

4.6 We received a lot of feedback from stakeholders on the system growth test. Most significantly, submitters commented that:[12]

4.6.1 The relationship between zone substation expenditure and capacity is weak, as not all expenditure on zone substations will result in a change in capacity. For example, comments included;[13]

> Firstly, not all system growth spending increases a zone substation's capacity, only expenditure on transformers increases zone substation capacity. Expenditure on items such as switchgear have no effect on zone substation capacity. Secondly, the cost of building a new zone substation is much more expensive than the cost of upgrading the transformer of an existing zone substation by the same capacity. In the Commission's test, these two activities are assumed to be comparable. – Network Tasman[14]

> Zone substation capex does not reflect system growth capex in its entirety. Zone substation capex is just one component of system growth capex that, on average, makes up about 30% of total system growth expenditure. However, there is substantial variance from year-to-year (and between distributors) in zone substations' share of total system growth expenditure… It is not clear how such a volatile component of system growth capex can be used to provide a good indicator of the internal consistency of the AMP forecasts for total system growth capex. - Aurora[15]

> Zone substation growth is only one way a network can grow. If zone subs have enough capacity new growth may come from increasing the capacity of the distribution feeders.
> The test doesn't recognise non-traditional system growth, like the investment needed to support DERs. – Wellington Electricity[16]

4.6.2 The data in Schedule 12(b) does not require disclosure of new zone substations. Comments included:[17]

> Finally, the Commission's accounts for all forecast expenditure, including the cost of new zone substations, but the total increase in zone substation capacity only accounts for changes in capacity for existing zone substations, it doesn't account for new zone substations. – Network Tasman[18]

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12 Submitters also raised issues arising from the quality of the data in ID. However, these concerns are not relevant if we change the approach as proposed.

13 Similar comments were made by Vector and Orion.

14 Network Tasman "Network Tasman DPP3 Draft reasons paper submission" (18 July 2019), p7

15 Aurora "Aurora Submission - DPP3 Draft Decision FINAL 2019" (18 July 2019), p11

16 Wellington Electricity "Wellington Electricity's response to DPP3 Draft Decision" (18 July 2019), p14

17 This point was also raised by ENA

18 Network Tasman "Network Tasman DPP3 Draft reasons paper submission" (18 July 2019), p7

4.7 We accept the points raised by submitters about the lumpiness of zone substation expenditure, and the variability of its effect in terms of increasing zone substation capacity. Furthermore, because distributors are not required to include planned new zone substations in Schedule 12(b) of ID and this data would be necessary for a full assessment, we would have to obtain it from detailed examination of AMPs, which would not be consistent with a relatively low-cost DPP.

4.8 For these reasons, we consider the draft system growth test must be removed or replaced.

4.9 The only alternative approach that submitters put forward for assessing system growth expenditure was to qualitatively assess the information provided in AMPs. Comments included:

> We were unable to identify a test that would address the different kinds of investments to address system growth issues due to the lumpy nature of these kinds of expenditures and the different types of expenditure requirements (e.g., new sub-station or upgrade of existing sub-station has very different cost characteristics). At this point we can only suggest that the Commission review the expenditure plans, or potentially allow the proposed expenditures with a wash-up to apply in the event the expenditure does not materialise. - Unison[19]

> …WELL supports using the next DPP3 period to collect better information through the Information Disclosures, to support a more robust test. However, given the potential under-investment in the network that applying the proposed test on EDBs could result in, WELL recommends using an EDB's systems growth forecast until better tests are developed. The Commission will have comfort that an EDB is delivering their overall capex programmes from the initial capex test which scrutinises past forecast performance. – Wellington Electricity[20]

4.10 We do not consider that accepting distributors' full system growth expenditure forecasts, as suggested by Wellington Electricity is a reasonable alternative to our draft test. System growth is an expenditure category that is consistently over-forecast by distributors.

4.11 A key reason for this is the ability for distributors to defer projects. Deferring projects is beneficial for consumers in the long term if it represents a genuine effort to achieve efficiencies. We also acknowledge that there can be significant uncertainty about future demand making system growth expenditure difficult to forecast. However, the potential to gain IRIS benefits from deferring projects means there is a clear incentive for distributors to make conservative assumptions (resulting in a higher forecast) when forecasting expenditure in this category.

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[19] Unison "Unison Submission on the DPP3 Draft Decision - 18 July" (18 July 2019), p18

[20] Wellington Electricity "DPP3 Draft Decision Cross Submission" (12 August 2019), p16

4.12 We also do not prefer an approach that relies on examining distributors' AMPs in detail, as suggested by Unison, as this is inconsistent with a relatively low-cost DPP. Further, while an expenditure wash-up is conceptually appealing, it could have implications for the IRIS mechanism and add undesirable complexity.

4.13 We therefore considered other analytical options for scrutinising distributors' system growth expenditure.

We considered a range of alternative approaches

4.14 We identified several factors that correlate with system growth expenditure that could theoretically be used to assess the reasonableness of the forecast expenditure. These can be thought of as:

4.14.1 primary factors – being the physical assets that forecast system growth expenditure would provide;

4.14.2 secondary factors – being the demand that drives the need for improvements or additions to assets; and

4.14.3 tertiary factors – being the consumers that create the demand.

4.15 We have been unable to identify reasonable tests using either primary or secondary factors affecting system growth expenditure. The main challenges are that:

4.15.1 We do not have adequate data about the assets that are the subject of the forecast investments, or the intended effects on system capability. For example, the zone substation capacity information in 12(b) is incomplete (as discussed), and we have no such information on future distribution substation capacity.

4.15.2 EDBs provide us with forecasts of their network peak demand. However, as identified by Aurora in its submission, this information is more relevant at a sub-network level. Aurora stated:

> We agree with the conclusion that maximum coincident system demand is not an appropriate indicator of the reasonableness of forecast system growth capex. However, we disagree with the assertion that system growth capex should be driven by maximum coincident system demand. Maximum coincident system demand is a poor indicator of system growth capex when distributors have subnetworks or when coincident GXP demand is growing quicker in some parts of the network than others.[21]

[21] Aurora "Aurora Submission - DPP3 Draft Decision FINAL 2019" (18 July 2019), p11

4.15.3 Without an independent touch-stone, using the available demand data can only test for the internal consistency of the distributors' forecasts. We do not have independent assessments of peak demand against which to scrutinise the peak demand forecasts. Further, in many cases, it appears that distributors' expenditure forecasts may be more considered than their demand forecasts.

4.16 We consider that consumer connections represent our best option for scrutinising system growth expenditure. Using connections is conceptually appealing, because we have Statistics New Zealand (StatsNZ) data as an external driver that we can anchor the forecasts against.

4.17 The draft decision included two tests to scrutinise consumer connection expenditure:

4.17.1 Assessing whether the forecast number of connections is proportionate to either historic annual connections or StatsNZ forecasts of population growth.

4.17.2 Assessing whether the average per-connection cost implied by forecast connection numbers and total expenditure (excluding identifiable major connections) were within 150% of historic average per-connection costs.

4.18 Submitters were broadly supportive of these tests as a way to scrutinise consumer connections expenditure. Specifically, comments included:

> We support the proposed scrutiny of consumer connection capex forecasts. When forecasts of population growth and historical ICP growth are combined with the per-connection expenditure test, a reasonably balanced view of the adequacy of the consumer connection capex forecast is obtained. - Aurora[22]

> By using two reference points – historical connection growth and forecast population growth – the test builds in some flexibility. This helps accommodate demand changes over time. - Vector[23]

> WELL supports the Commission's approach of assessing per-connection expenditure. The 150% cap takes into account cost differences between different connection types. - WELL[24]

We propose treating system growth and consumer connections expenditure together

4.19 We are now proposing to treat system growth and consumer connections expenditure together when scrutinising distributors' expenditure forecasts.

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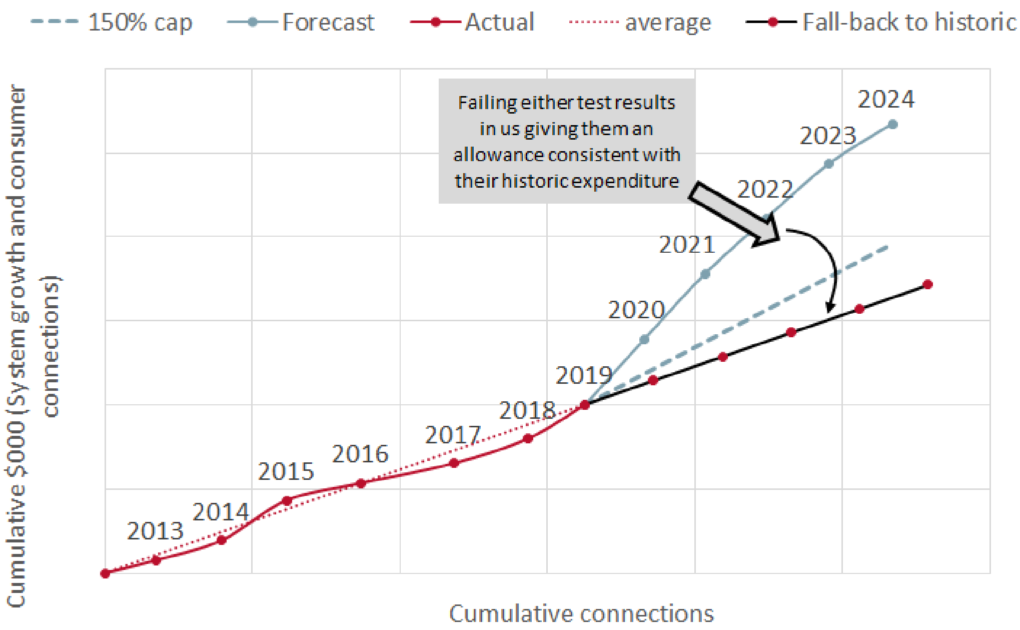
[22] Aurora "Aurora Submission - DPP3 Draft Decision FINAL 2019" (18 July 2019), p 10

[23] Vector "Vector Submission draft DPP final" (18 July 2019), p 24

[24] Wellington Electricity "Wellington Electricity's response to DPP3 Draft Decision" (18 July 2019), p 14

4.20 Figure 4.1 demonstrates the effect of these tests for an example distributor, assuming no other changes are made from the draft decision. It shows the distributor's cumulative spend on system growth and new connections since 2013—actual and forecast—against their cumulative new connections over the same period. The distributor is forecasting new connections similar to what they have seen historically, but cost growth well beyond 150% of their historic actual. Because they fail the per-connection cost test, they would be scaled back to an amount consistent with their historic expenditure.

Figure 4.1 Cumulative growth capex versus connections since 2013, for an example distributor



4.21 We consider that treating system growth and consumer connections expenditure together is appropriate because:

4.22 **There is a reasonable correlation between system growth capex and the number of connections over time.** The existence of a relationship is not surprising. However, the variability of investment in system growth requires a long data series for that relationship to be apparent—particularly for smaller distributors. Further, the relationship will be different for each distributor depending on the number, location and type of new customers connecting to the network.

4.23 Our analysis suggests that we have a sufficiently long data series that the relationship is leverageable in scrutinising system growth expenditure. This is demonstrated by Figure 4.2. It shows each distributor's combined system growth and consumer connections expenditure (including capital contributions) for the period 2013-2019 (y axis), compared with their growth in consumer connections over that same period (x-axis). The r-squared value of 0.89 indicates a meaningful relationship. The gradient of the trend line suggests an average long-run per-connection cost of $11,000.

4.24 Figure 4.3a and b show this same information for consumer connection expenditure and system growth expenditure separately. This demonstrates that the relationship between consumer connection expenditure and connections is stronger than for system growth expenditure. However, a meaningful relationship is evident for both, and indeed strongest when the two categories are combined.

Figure 4.2 Combined consumer connection and system growth expenditure on assets versus ICP growth for 29 distributors over 2013-19

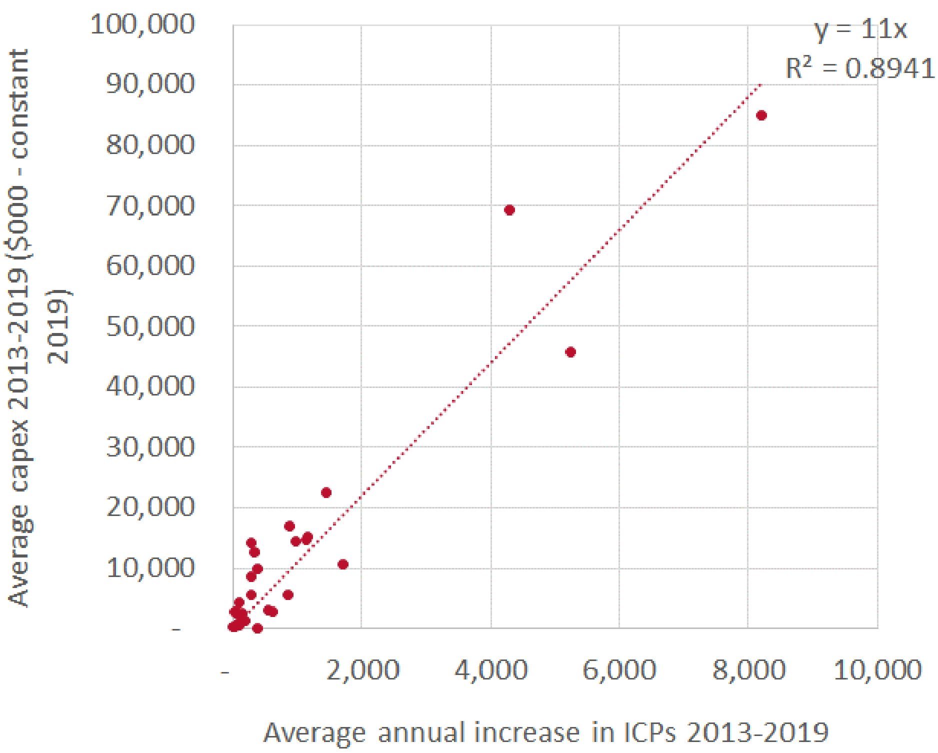
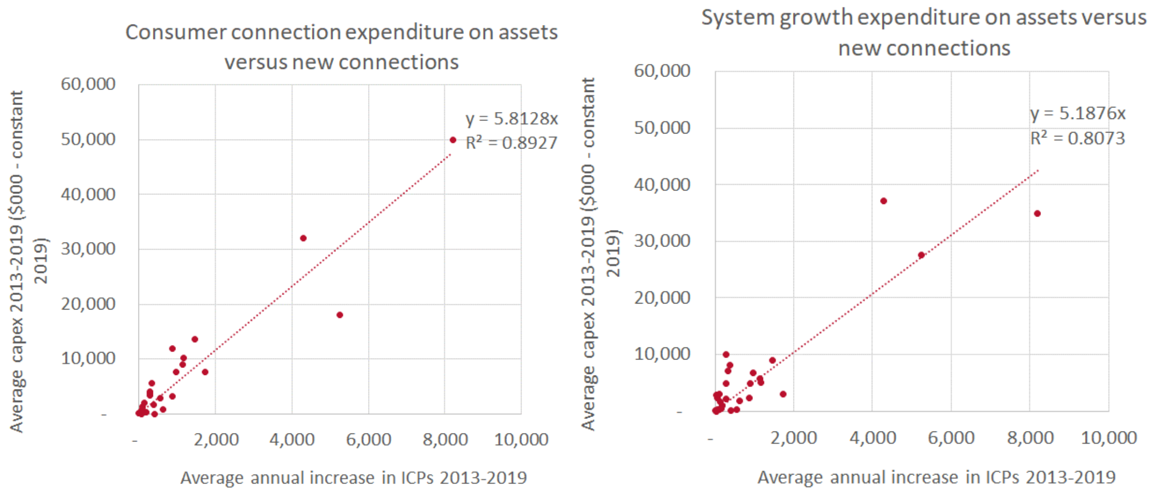


Figure 4.3 Figure 3a and b: Consumer connection and system growth expenditure on assets versus ICP growth for 29 distributors over 2013-19



4.25 **There is a blurred line between consumer connections and system growth expenditure**, as connecting single consumers can cause a need to reinforce the network to accommodate the change in demand, and the point of delineation is not always clear. This means there are inconsistencies in how different distributors classify the expenditure, and potentially inconsistencies in how individual distributors categorise the expenditure over time. For a similar reason, we bundled together expenditure for asset replacement and renewals and reliability, safety and environment when scrutinising this expenditure for our draft decision. Effectively, our proposed approach results in us recognising three broad expenditure categories – growth, renewals and 'other' (being asset relocations and non-network expenditure).

4.26 **The tests we used to scrutinise consumer connections expenditure are simple.** This means we avoid an illusion of accuracy that we cannot practically achieve with the quality of data we have. We also avoid the need to undertake new and complicated analysis within the relatively low-cost constraints of the DPP. We considered several ways to assess system growth expenditure while accounting for things like demand density (e.g. km of line per customer), and average customer demand. However, these approaches tended to add complexity for little obvious and consistent benefit across the distributors.

4.27 **The tests appear to produce logical results**—identifying distributors that have forecast system growth expenditure that is out of step with their past expenditure and independent expectations of growth in their regions.

4.28 Treating system growth and consumer connections expenditure together is not a perfect solution. The main arguments against this approach are that:

4.28.1 It subjects a greater proportion of expenditure to the same test, which increases the risks from any single test being imperfect.

4.28.2 The tests were designed for, and may hence be better suited to scrutinising consumer connections than system growth. Specifically:

4.28.2.1 Connections are a less direct driver of system growth capex than consumer connections expenditure. Existing connections can also be a source of demand growth. Distributors themselves tend to rely on localised demand forecasts when forecasting system growth expenditure.

4.28.2.2 While there is clearly a relationship between system growth expenditure and connections, it is weaker over short timeframes than the relationship between consumer connections expenditure and connections, and to some extent will just reflect distributor scale.

4.28.2.3 System growth is a lumpier expenditure category than consumer connections. There will reasonably be periods where an distributor needs to invest significantly in system growth, followed by periods of relatively subdued system growth activity. Our tests – and a DPP more generally - cannot robustly account for this variability, which may ultimately need to be addressed through CPPs, or potential reopener mechanisms.

4.29 Despite these imperfections, we consider the approach remains appropriate. The per-connection cost test includes a 150% buffer, which is generous, with only one distributor affected by this test.

4.30 We also note that our proposal to scrutinise system growth and consumer connections together should be considered in the context of other changes we may make to how we set capex forecasts in our final decision, having considered all the feedback from submitters.

4.31 Further, in its submission on the draft decision, the Electricity Networks Association (ENA) submitted:

> "We consider that the capping approach does not deal with lumpy capital expenditure well, which may affect smaller EDBs more than larger ones. This issue could be improved by the Commission also considering evidence of committed expenditure for large capex projects." [25]

4.32 Despite proposing an improved test for system growth, we recognise that it has some constraints so we will still consider the ENA's suggestion above. In its submission on the draft decision, Wellington Electricity suggested expanding the connection reopener to other areas of capital expenditure like system growth, which would be one way to provide a mechanism for further scrutiny of system growth expenditure that does not meet the proposed system growth test.[26] So, we are considering this.

4.33 In the longer-term, we would like to improve the information that we seek from distributors under the ID requirements to facilitate improved scrutiny tests for DPP4.

[25] ENA "ENA submission on DPP3 Draft Decision - final" (18 July 2019), paragraph 79.

[26] Wellington Electricity "Wellington Electricity's response to DPP3 Draft Decision" (18 July 2019).

Chapter 5 Options for approaching normalisation of major events

Purpose of this chapter

5.1 This chapter discusses options for improving our approach to normalising major events for quality standards and incentives. Given the issues raised with our draft approach in submissions and in our targeted quality of service workshop, we consider it useful to test this proposal with stakeholders prior to our final decision.

5.2 We note that these changes have not been implemented in the quality models published alongside this paper.

Purpose of normalisation

5.3 Reliability and the metrics we use to measure it (SAIDI and SAIFI) are inherently volatile. Year-on-year volatility in total SAIDI or SAIFI may be the result of major events, rather than the result of underlying declines or improvements in network performance. Specifically, the size and number of major events a distributor experiences in a given year can have a material impact on its total SAIDI or SAIFI performance.

5.4 The purpose of normalisation is to limit the impact of these major events so that the standards we impose, and the incentives distributors face are not merely reflecting unpredictable events (such as severe weather events).

Proposed approach

5.5 We are considering moving to a 24-hour rolling assessment for identifying major events. Once identified as a major event, those half-hours within the major event that exceed 1/48th of the boundary value will be replaced with (capped at) 1/48th of the boundary value.

5.6 In terms of specific proposals:

5.6.1 **Assessment frequency (resolution):** major events would be assessed on a half-hourly basis – no change from the draft approach;

5.6.2 **Assessment length (rolling period):** major events would last for at least 24 hours – change from the draft approach;

5.6.3 **Major event threshold (boundary value):** would be defined in a way which creates an expectation of 23 major events in a ten-year period, specifically the 1104th highest rolled half-hour during the ten-year reference period (23 major event days x 48 half-hour rolling periods) – change from the draft approach; and

5.6.4 **Major event replacement:** any half-hour within a major event that exceeds 1/48th of the boundary value would be replaced with 1/48th of the boundary value.

5.7 In summary, for SAIDI and SAIFI, our updated proposal replaces 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 any 24-hour period that exceeds the boundary value.

5.8 When considering these alternatives, it is worth emphasising that their effect is symmetric. The same treatment is applied to the historic dataset to derive standards and targets, and to the assessment of compliance and incentives during the DPP3 period.

Alternatives considered

5.9 Alternatives for the different components of normalisation we have considered in arriving at this proposal are set out in Table 5.1. The following sections then discuss the advantages and disadvantages of different options in terms of their incentive properties and stakeholder views of them.

Table 5.1 Alternative approaches to normalisation

Component	DPP2 approach	Draft approach	ENA proposal[27]	Updated proposal
Assessment frequency	Daily	Half-hourly	Undefined	Half-hourly
Assessment length	Calendar day	3-hourly	24-hourly	24-hourly
Boundary value	23rd highest calendar day	150th highest half-hour	Equivalent of 23rd highest day	1104th highest half-hour (23 x 48)
Replacement value	Boundary value	1/8th of the boundary value for 3 hours leading up to major event	Zero or daily average	1/48th of the boundary value for each half-hour within the major event that exceeds 1/48th of the boundary value

5.10 The average impact of alternative normalisation methodologies for SAIDI and SAIFI during the reference period are outlined in Figure 5.1 and Figure 5.2 respectively. These figures represent the simple annual average of normalised SAIDI and SAIFI across distributors over the 1 April 2009 to 31 March 2019 reference period under alternative normalisation methodologies we have considered.

27 ENA "Follow Up letter on quality of service workshop" (22 August 2019).

Figure 5.1 SAIDI normalisation impact

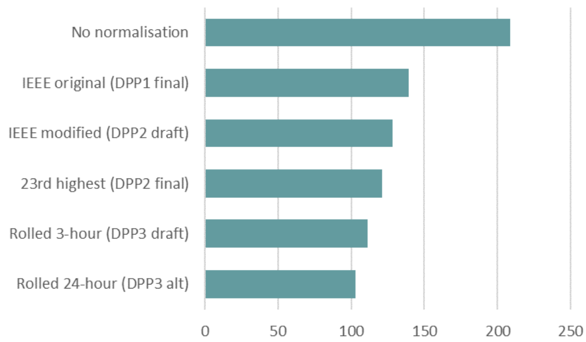
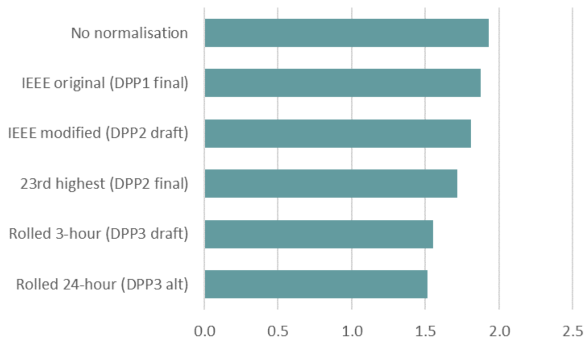


Figure 5.2 SAIFI normalisation impact



Analysis

DPP2 approach

Advantages

5.11 The DPP2 methodology is established and familiar to the industry. It was developed for consistency with the IEEE normalisation methodology, but in a way that is responsive to New Zealand's conditions (specifically, the number of 'zero interruption' days some distributors in New Zealand experience).

Disadvantages

5.12 The use of a fixed calendar day is somewhat arbitrary and means that significant events that span two calendar days may not be captured adequately.

5.13 We also considered that major events based on a full day would capture interruptions not part of a major event, for example on the most part, major events appeared much shorter than 24 hours.

5.14 Furthermore, as acknowledged in the draft reasons paper, annual compliance with quality standards and financial incentives are driven largely by the frequency of major events.[28]

Draft decision approach

Advantages

5.15 To resolve the issues above, in our draft decision, we proposed moving to an approach that worked on a three-hourly rolling basis, with replacement of major events with a pro-rated boundary value.

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[28] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision – Reasons Paper" (29 May 2019).

5.16 The move to a rolling window meant that all interruptions were treated equally regardless of the time of day they occurred. The implementation of a pro-rated boundary value meant that the frequency of major events had less impact on compliance and financial incentives, while not creating the same threshold effects that removing the entire impact of a major event has.

5.17 In general, submissions were supportive of the concept of a rolling approach,[29] although Eastland Network and ENA raised concerns that the extra complexity would require investment in outage recording systems.[30] Many distributors also supported reducing the impact the frequency of major events has on compliance and financial incentive outcomes, although some suggested it did not go far enough.[31]

Disadvantages

5.18 We acknowledge that the rolling methodology introduces additional complexity. However, we disagree with Eastland Network and ENA that this issue would require changes to outage reporting system given the required data should already be recorded. We will publish a model to assist distributors to comply with the normalisation approach we adopt.

5.19 Stakeholders also expressed concern that our draft decision deviated from the IEEE methodology in a way that would change the expected frequency of major events and create a risk of unforeseen outcomes.[32]

Ongoing impact of major events

5.20 In submissions, submitters noted that even though major events may often not last longer than three hours, their effects can continue for a longer period.[33] For example, a major storm causing widespread damage can continue to impair efforts to restore any subsequent interruptions after the storm is over – as crews cannot react to a ‘normal level’ of interruptions as they normally would.

5.21 We agree with this concern. For the reasons discussed below, we have proposed changing the assessment length to a 24-hour period.

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29 For example, refer Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 18-19; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 32.

30 Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

31 For example, refer ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 32-33.

32 For example, refer ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 31.

33 Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 18-19; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

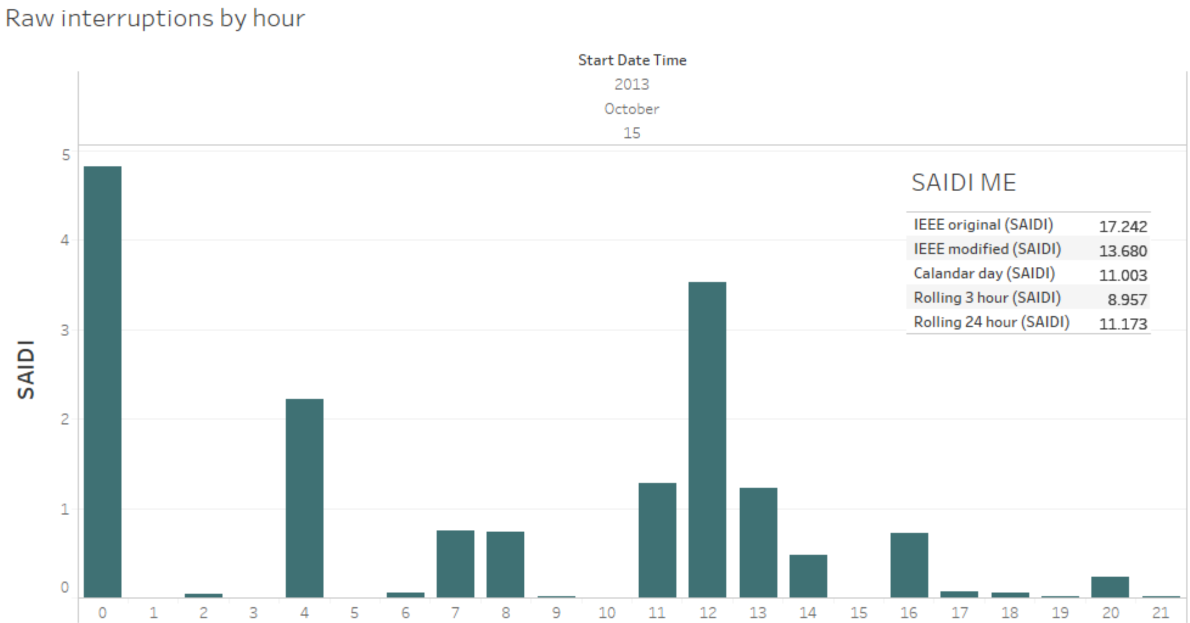
False negative and false positives

5.22 Submitters questioned whether the move to a three-hour window risked creating false positives and false negatives, highlighting that certain events that were major events under the calendar day DPP2 methodology were not captured under the draft methodology.[34] In discussions at the quality of service workshop, attendees highlighted that we should consider not only how many major events are triggered in a given period, but the properties of those major events.[35]

5.23 Over the reference period across all distributors, around 15% of major events captured by the DPP2 methodology were not captured by the draft methodology, and around 15% of the major events not captured by the DPP2 methodology were captured. Representative examples of these types of events are shown in Figure 5.3 and Figure 5.4.

5.24 However, we do not consider this difference alone is reason enough to move back to a 24-hour approach. While we acknowledge that the different methodologies do change the profile of what is considered a major event, we considered a longer window is more likely to trigger major events that are driven by the accumulation of multiple smaller events.

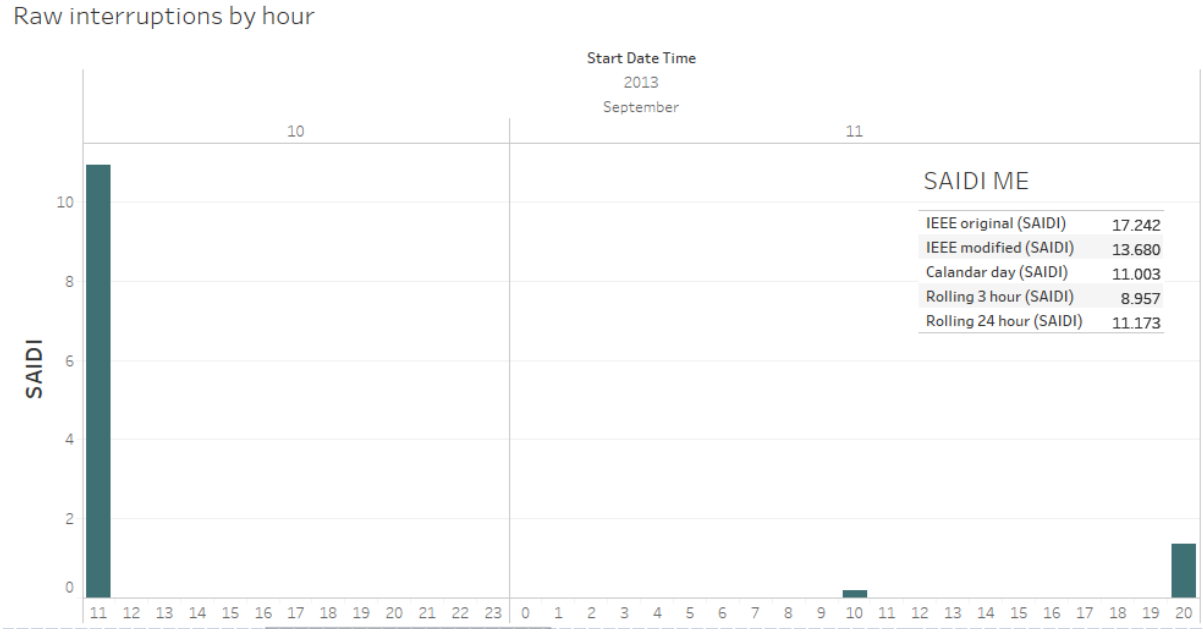
Figure 5.3 Example of major event calendar day NOT triggering a 3-hour major event



[34] As an example, Orion provided an example in which a snowstorm occurring over two days in August 2011 was normalised both days previously but not under the draft methodology. We note that with an updated reference period this event is not considered a major event under any of the methodologies we tested. Refer Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), pp. 10-11.

[35] Commerce Commission "EDB DPP3 – Targeted Workshop on Quality of Service" (16 August 2019).

Figure 5.4 Example of 3-hour major event NOT triggering a major event calendar day



Different normalisation depending on major event profile

5.25 Due to replacing all half-hours within a major event and the rolling nature of the draft methodology, the degree to which a major event is normalised depended on the profile of the major event. For example, a major event that is triggered in a single half-hour is normalised for 5.5 hours rather than 3.0 hours. So even though both events in Figure 5.5 and Figure 5.6 below had the same raw SAIDI, one was normalised to 1/8th of the boundary value with the other almost double that.

Figure 5.5 DPP3 draft normalisation (1)

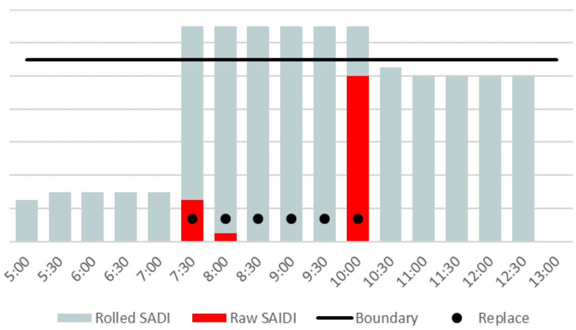
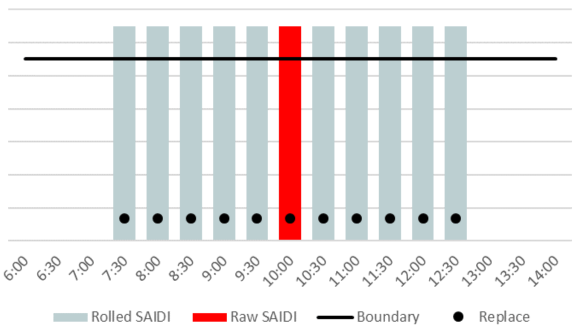


Figure 5.6 DPP3 draft normalisation (2)



Perverse incentives

5.26 Finally, submitters also noted that there is a potential perverse incentive where distributors could prioritise restoration work after a major event rather than on what best meets customer needs (reducing total outage duration) to optimise incentive/compliance performance.[36]

5.27 Extending the assessment length while normalising only the biggest half-hours (discussed below) can still achieve the original intention of reducing major events to three hours.

5.28 In the context of a three-hour window, distributors raised (via submissions and in the workshop) an incentive to prioritise the restoration of interruptions that occurred after the major event, rather than the major event itself.[37] This is because the major event will not be subject to additional SAIDI like subsequent interruptions will be. While we consider this incentive exists under any approach to normalisation, we agree that this is exacerbated by the shorter normalisation window.

ENA proposal

5.29 The ENA proposed an alternative methodology (summarised in Table 5.1 above) that it considered resolved the issues it raised with our draft methodology.[38]

5.30 Broadly speaking, we agree with the ENA's approach of rolling on a 24-hour, rather than 3-hour basis. However, we do not consider replacement of an entire major event with a zero or daily average appropriate. This approach exacerbates the threshold effect where a distributor is just below a major event boundary or just over it. This produces arbitrary outcomes, and penalises distributors who respond well to an event, keeping their SAIDI or SAIFI values below the boundary, and avoiding a major event.

5.31 Additionally, it is important to note that while the causes of major events will often be beyond a distributor's control; its responses to it are not. Prompt restoration of supply, even in the context of a major events, is still of value to consumers. As such, we consider there is significant benefit in retaining some incentive to avoid a major event being triggered.

[36] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 18-19; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

[37] Commerce Commission "EDB DPP3 – Targeted Workshop on Quality of Service" (16 August 2019).

[38] ENA "Follow Up letter on quality of service workshop" (22 August 2019).

Updated Commission approach

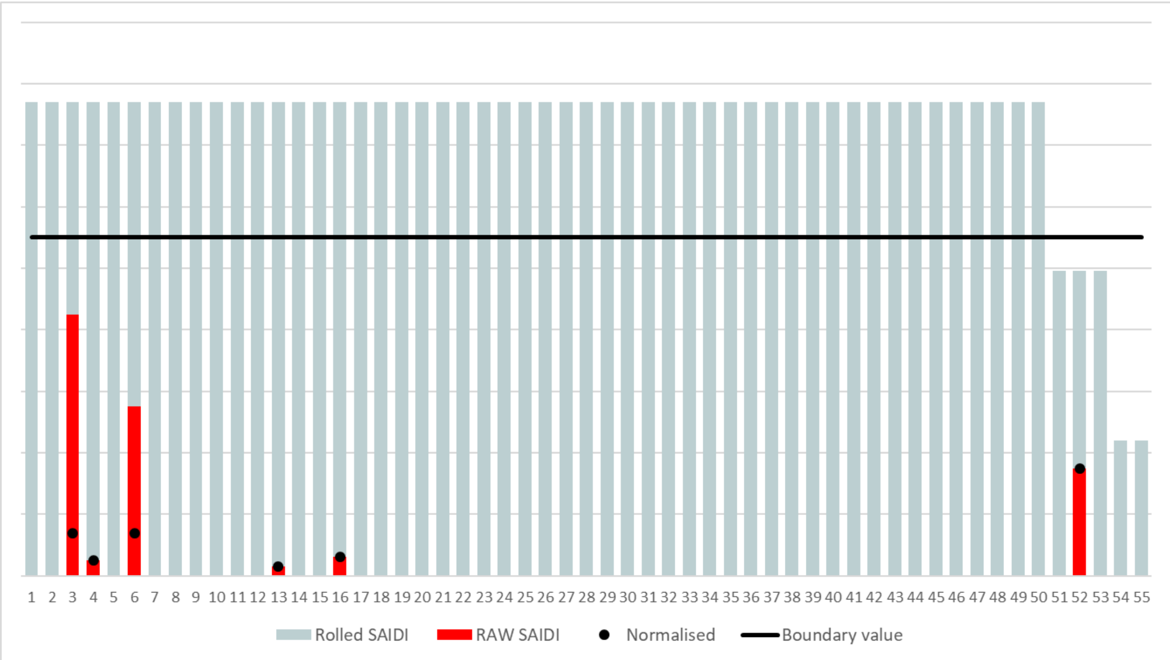
5.32 To remedy the difficulties with the ENA's approach, while maintaining the benefits of it, we propose identifying major events on a 24-hour rolling (and extending, where necessary) basis, but to only normalise the half-hour periods that exceeded 1/48th of the boundary value back to 1/48th of the boundary value.

5.33 This proposal is illustrated in Figure 5.7 below, where the raw half-hourly SAIDI (and similarly for SAIFI) is normalised to 1/48th (not to scale) of the boundary value if:

5.33.1 that half-hour is part of a 24-hour period that exceeds the SAIDI boundary value and;

5.33.2 1/48th of the raw half-hourly SAIDI is greater than 1/48th of the SAIDI boundary value.

Figure 5.7 Proposed approach – illustrative example



Advantages

5.34 As stated above the primary purpose of normalisation is to reduce volatility in reported reliability performance, and to focus compliance and incentive outcomes on instances of poor distributor performance.

5.35 We consider that the approach we have outlined in this paper better achieves this goal than the current DPP2 approach, while remedying the incentive difficulties created by our draft DPP3 approach.

5.36 Under any approach to normalisation, there may be a potential disincentive to reconnect customers in stages during a major event if they will need to be disconnected again. This is because, as it stands, the entire SAIDI and SAIFI impact of an interruption accrues to the start time of the interruption. Therefore, a 'new' interruption resulting from the staging will restart the SAIDI and SAIFI count at a new time.

5.37 Short of defining an interruption to include staged events, and defining what constitutes a staged event, this potential incentive will likely exist to some degree regardless of how we replace major events. However, we consider that replacing the SAIDI or SAIFI value for a half-hour with 1/48th of the boundary value significantly decreases any benefit of avoiding staged restoration.

Disadvantages

5.38 Under any approach to normalisation, distributors may have an incentive to 'trigger' a major event by increasing SAIDI or SAIFI. This difficulty persists with our proposed approach, although:

5.38.1 distributors have significant non-regulatory incentives to avoid this behaviour (reputational and professional factors);

5.38.2 major events are replaced with the pro-rated boundary value rather that a lower replacement value, making the incentive weaker; and

5.38.3 greater transparency in major event reporting will assist in mitigating this risk.

Attachment A Updates to draft DPP models and data

Model/input title	Draft models	Updated models
Vanilla WACC (67th percentile)		
Cost of Capital determination	April 2019	**September 2019**
Population growth model		
StatsNZ: Population projections (last update)	April 2019	April 2019
CPI model		
StatsNZ: Actual consumers price index	December 2018	**June 2019**
RBNZ: Forecast CPI inflation	February 2019	**August 2019**
Input cost inflators model		
NZIER: LCI, CGPI and PPI (historic & forecast)	April 2019	**August 2019**
Opex projections feeder circuit length model		
ID disclosure years	2015-2018	**2015-2019**
Capex projections feeder gating model		
AMP disclosure years	2014-2018	**2014-2019**
ID disclosure years	2012-2018	**2012-2019**
Operating lease assumptions	Not included	Not included
Capex projections model		
AMP disclosure years	2018	**2019**
ID disclosure years	2013-2018	**2013-2019**
Input cost inflators model: capex		**Updated**
Population growth model		Not updated
Operating lease assumptions	Not included	Not included
Spur asset purchase assumptions	Not included	Not included
Opex projections model		
ID disclosure years	2013-2018	**2013-2019**
Partial productivity factor		Not updated
Input cost inflators model: network & non-network		**August 2019**
Opex projections feeder circuit length model	2015-2018	**2015-2019**
Opex econometrics: elasticities		Not updated
Population growth model		Not updated
Operating lease assumptions	Not included	Not included
FENZ levies	Not included	Not included
Pecuniary penalties	Not included	Not included

Title	Draft models	Updated models
Disposals model		
Vanilla WACC (67th percentile)		**Updated**
ID disclosure years	2015-2018	**2015-2019**
CPI model		**Updated**
Financial model		
Vanilla WACC (67th percentile)		**Updated**
Cost of debt		**Updated**
ID disclosure years	2018	**2019**
CPI model		**Updated**
Capex projections model		**Updated**
Opex projections model		**Updated**
Disposals model		**Updated**
Constant price revenue growth model		
Compliance statements	2016-2018	**2016-2019**
ID disclosure years	2016-2018	**2016-2019**
CPI model		**Updated**
Revenue change model		
Vanilla WACC (67th percentile)		**Updated**
Constant price revenue growth model		**Updated**
Financial model: MAR data		**Updated**
Transpower forecast GXP charges	RCP3 proposal	Not updated
DPP2 X values		Not updated
MAR waterfall model (2015 to update)		
DPP2 financial model inputs	DPP2 final	DPP2 final
DPP3 financial model inputs	Draft model	**Updated**
Revenue change model: est. 2020 allowable revenue		**Updated**
MAR waterfall model (draft to update)		
DPP3 financial model inputs - Draft decision		Not updated
DPP3 financial model inputs	Draft model	**Updated**
Revenue change model: est. 2020 allowable revenue		**Updated**
RAB waterfall model		
ID disclosure years	2018	**2019**

Title	Draft models	Updated models
Reliability standards and incentives supporting data and intermediate calculations model		
Disclosure years "Energy delivered"	2016-2018	**2017-2019**
Disclosure years "ICPs"	2016-2018	**2017-2019**
MAR from DPP3 financial model	2021-2025	**Updated**
MAR for Powerco CPP	2021-2023	**Updated**
SAIDI incentive rates for DPP2 ($/SAIDI)		**Not updated**
Circuit length		**Updated**
Inputs from Stata model - all		**Updated**
Financial model		**Updated**
Operating lease model		
Model build	Did not exist	Model included (no data)