TRANSPOWER

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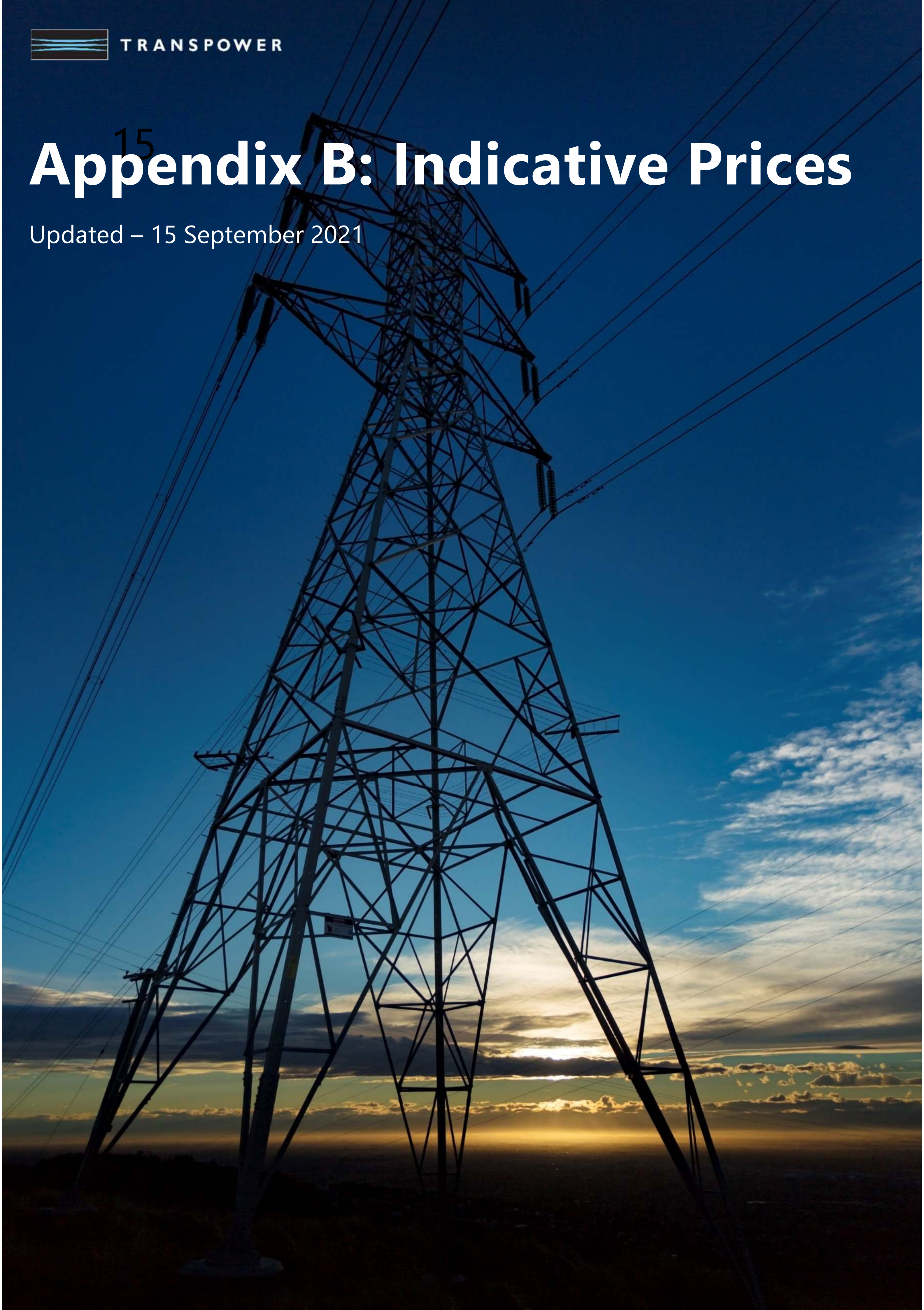
Appendix B: Indicative Prices

Updated – 15 September 2021



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1 Introduction

1. This appendix presents the indicative prices Transpower has modelled consistent with the proposed TPM, and explains the high-level approach and process followed to model them.
2. The indicative prices reflect modelling performed for the 2021/22 pricing year, to provide a comparison with prices under the current TPM. Charges under the proposed TPM are also projected out to the 2034/35 pricing year to indicate how charges may evolve under the TPM proposal. The prices are illustrative only and subject to change as part of TPM finalisation, ongoing verification of underlying data sets, and ongoing evolution of our customer and asset base.

2 Requirements of the Code and the Authority's process decision

3. Clause 12.89(2) of the Electricity Industry Participation Code (the **Code**) states the requirement for Transpower's Proposal to include indicative prices:

> **Form of proposed transmission pricing methodology**
>
> …
>
> (2) **Transpower's** proposed **transmission pricing methodology** must include indicative prices to allow the **Authority** and interested parties to understand the impact of the methodology on **designated transmission customers**.

4. Clause 12.83 of the Code requires the Authority, when publishing new TPM Guidelines, to also publish the process Transpower must follow in developing a TPM consistent with those Guidelines:

> **Authority must publish process and guidelines for development of transmission pricing methodology**
>
> After consideration of submissions in clause 12.82(3), the **Authority** must, as soon as reasonably practicable, **publish**—
>
> (a) the process for the development of the **transmission pricing methodology**; and
>
> (b) any guidelines that **Transpower** must follow in developing the **transmission pricing methodology**.

5. The Authority's process decision under clause 12.83 requires that Transpower's *"proposed TPM must include indicative prices to allow its impacts to be understood"*, and *"Transpower's development of the proposed new TPM must include [a step to] calculate indicative prices to show the impact of the proposed TPM on transmission customers."*[1]

3 Indicative Pricing Model

6. Transpower has developed a model to produce indicative pricing consistent with its proposed TPM. The model comprises a number of process steps, databases and Excel spreadsheets. The architecture of the Indicative Pricing Model (the **Model**) is shown in Appendix C of this paper. The Excel spreadsheet components of the Model are also provided as part of our TPM proposal package.
7. Our indicative pricing is for the 2021/22 pricing year. This allows our customers to see how their current charges compare (indicatively) to what their charges would have been under the proposed TPM. This approach also aligns with the Guidelines' requirement for all investments in the interconnected grid from July 2019 to be subject to the Benefit-Based Charge (**BBC**).
8. There are three core charge types under the proposed TPM: Connection charges, BBCs and Residual Charges.
9. ***Connection charges:*** The changes we have proposed to connection charges are technical - to fix errors, remove redundancy, reduce ambiguity and achieve better alignment. As such our proposal has no pricing impact on existing price outcomes for most customer level connection charges.[2] Connection charges have been calculated within Transpower's Pricing System (**TPS**) and are an input to the Model.

[1] Refer Part 12 Code, clause 12.83. The Authority's TPM development process decision, including the timeline, is specified in Box 1 of its 2020 Decision (reference document #3), pages 111-112.

[2] Chapter 5 of the TPM Proposal Reasons paper explains the reasons for our proposals for the connection charge. Our indicative pricing for the 2021/22 pricing year has not required any application of our proposals in relation to first mover disadvantage.

10. ***Benefit-based charges:*** The BBC is a new component of the proposed TPM. The BBC applies to all benefit-based investments (**BBIs**). There are three categories of BBIs under the proposed TPM:[3]

    10.1 ***High-value post-2019 BBIs:*** any investment in the interconnected grid, made from July 2019 onwards, for which the capital cost is expected to exceed $20m.[4] The allocation of costs for these BBIs is calculated on a case-by-case basis under a standard method. There were no such BBIs for the 2019/20 period covered by our indicative pricing. We have instead developed case studies for two high-value post-2019 BBIs to help stakeholders better understand the potential impact of the standard methods on customer charges.[5]

    10.2 ***Low-value post-2019 BBIs:*** any investment in the interconnected grid, made from July 2019 onwards, that is not high-value (that is, it is not expected the capital cost will exceed $20m). The allocation of costs for these BBIs is calculated under the simple method.

    10.3 ***Schedule 1 BBIs:*** seven historic (pre-July 2019), high value investments in the interconnected grid. Schedule 1 of the Guidelines (and Appendix A of the proposed TPM) specify the BBC allocations that apply for recovery of the remaining costs of these 7 BBIs.[6]

11. ***Residual charges:*** the balance of the revenue Transpower (as the grid owner) can recover from its customers in each pricing year is allocated to the residual charge based on the remaining residual revenue after amounts recovered via other transmission charges have been deducted from Transpower's recoverable revenue.

12. The Model also calculates the effect on prices from the ***Transitional Cap***. The transitional cap limits load customers' transmission charge increases due to BBCs for Schedule 1 BBIs and residual charges, relative to their interconnection charge under the current TPM for the pricing year ending 30 April 2020. Transitional cap recovery charges are then calculated based on how much customers pay by way of BBCs for Schedule 1 BBIs and residual charges

13. Our indicative pricing assumes that the two existing prudent discount agreements (Waipori and Aniwhenua/Matahina) and existing notional embedding contract (BlackPoint) have no effect under the proposed TPM.

4 Process to apply the proposed TPM

14. This section describes the key process steps and calculations applied to determine indicative prices. The descriptions are not exhaustive, and are intended to provide a high-level

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[3] Our proposals for determining the revenue amount to be recovered for each benefit-based investment (BBI), its "covered cost", are explained in Chapter 6 of the TPM Proposal Reasons paper, and the proposed approach to allocation of BBCs to the customers expected to benefit from them in Chapter 7.

[4] The Guidelines (reference document #4) set the threshold for application of a BBC standard method, which apply to high-value post-2019 BBIs, by reference to the **base capex threshold** defined in Transpower Capex IM (reference document # 71). The **base capex threshold** is currently $20m.

[5] The indicative pricing effect of the BBC Standard method is shown via case studies. Refer Appendix D: *BBC Price-quantity method case study - CUWLP* and Appendix E: *BBC Resiliency method case study - WUNIWM Waikato dynamic reactive device*.

[6] Adjustments have been made to Schedule 1 allocations to provide for new customer connections and disconnections, and to correct for errors immaterial to indicative prices. These changes are captured in the allocations provided in Appendix A of the proposed TPM.

overview. The section also shows the results of each main process step that make up the indicative price that Transpower's customers would pay under the proposed TPM.

4.1 Recoverable Revenue under the TPM

15. The Commerce Commission (**Commission**) determined that Transpower (as the grid owner) is allowed to recover a maximum allowable revenue (MAR) of **$798.8m** from its customers in pricing year 2021/22. The MAR translates to recoverable revenue under the proposed TPM.

4.2 Calculate the Connection charge

16. The changes to the existing connection charge are technical and as such there would be no impact on existing price outcomes for most customers for connection charges. Therefore, Transpower's indicative pricing for the connection charge is the same as the actual 2021/22 connection charge for most customers.[7]
17. Total connection charges are **$121.3m or 15%** of total charges for the 2021/22 pricing year.

4.3 Calculate the BBCs

Calculate covered costs

18. The covered cost of a BBI is the share of our recoverable revenue, that is recovered from the beneficiary customers of the BBI through its BBC. Chapter 6 (BBC Covered Cost) explains our proposal for determining the covered cost for each BBI.
19. The components comprising the covered cost of BBIs (or, how the total BBC for each BBI is determined each pricing year) are:
    19.1 Accounting depreciation;
    19.2 Capital charge;
    19.3 Attributed opex; and
    19.4 Tax.
20. For the 2021/22 pricing year, the total covered cost of BBCs is **$228.4m or 29%** of our recoverable revenue.
21. The below table shows BBCs contributing to our indicative prices for the 2021/22 pricing year. The Schedule 1 BBIs make up 95% of total BBCs. The remaining 5% of BBCs recover the cost of many low-value BBIs whose costs are allocated using the simple method (referred to in the table as Simple Method BBIs).[8]

[7] Adjustments have been made to connection charges for the two existing prudent discount agreements (Waipori and Aniwhenua/Matahina) and existing notional embedding contract (BlackPoint).

[8] For Simple Method BBIs, 'Low Voltage' refers to BBI assets operating at 110kV or lower.

Table 1 Covered cost and its components, for Schedule 1 BBIs and Simple Method BBIs

	Benefit Based Investment	Accounting Depreciation ($000)	Capital charge ($000)	Attributed opex component ($000)	Depreciation tax loss/gain & income tax on the capital charge ($000)	Covered Cost ($000)
Schedule 1	BPE-HAY A&B Reconductoring	1,745	3,256	1,763	(1,196)	**5,568**
	HVDC	39,150	26,184	49,334	8,225	**122,893**
	LSI Reliability	712	1,506	720	(78)	**2,860**
	LSI Renewables	633	1,754	640	(165)	**2,862**
	North Island Grid Upgrade Project (NIGUP)	13,902	35,739	14,049	4,422	**68,112**
	WRK-WKM C (Wairakei Ring)	2,035	5,778	2,057	88	**9,957**
	Upper North Island Dynamic Reactive Support (UNIDRS)	1,436	1,748	1,451	239	**4,873**
Simple Method	Bay of Plenty Low Voltage	113	78	114	(77)	**228**
	Cromwell Low Voltage	-	-	-	-	**-**
	Central North Island Low Voltage	517	485	522	(160)	**1,364**
	Central South Island High Voltage	27	23	27	(11)	**67**
	HVDC link	281	124	284	(135)	**554**
	Hawkes Bay High Voltage	26	8	27	(6)	**55**
	Hawkes Bay Low Voltage	164	74	166	(25)	**378**
	Lower North Island High Voltage	940	375	950	124	**2,389**
	Lower South Island High Voltage	216	130	218	19	**583**
	Northland High Voltage	150	70	152	(10)	**362**
	Northland Low Voltage	48	23	49	8	**128**
	Nelson Marlborough Low Voltage	104	107	105	(59)	**257**
	Southland Low Voltage	105	82	107	(70)	**225**
	Timaru Low Voltage	2	1	2	(1)	**3**
	Upper North Island High Voltage	268	116	271	46	**701**
	Upper North Island Low Voltage	514	306	520	88	**1,428**
	Upper South Island High Voltage	141	104	142	(10)	**378**
	Upper South Island Low Voltage	163	70	165	(69)	**329**
	Waitaki Low Voltage	2	1	2	(2)	**4**
	Wellington Low Voltage	576	330	582	64	**1,552**
	Waikato Low Voltage	124	69	125	(57)	**260**
	Total	**64,096**	**78,540**	**74,543**	**11,190**	**228,369**

22. Figure 1 below shows the contribution to total BBCs of each component comprising the covered cost, on average across all BBIs.
23. The majority of covered cost is made up of three similarly sized cost components:
    23.1 Capital charge (34%),
    23.2 Attributed opex component (33%) and
    23.3 Accounting depreciation (28%).
24. The remaining 5% of covered cost is attributable to direct tax implications, stemming from depreciation tax losses/gains and income tax on the capital charge.

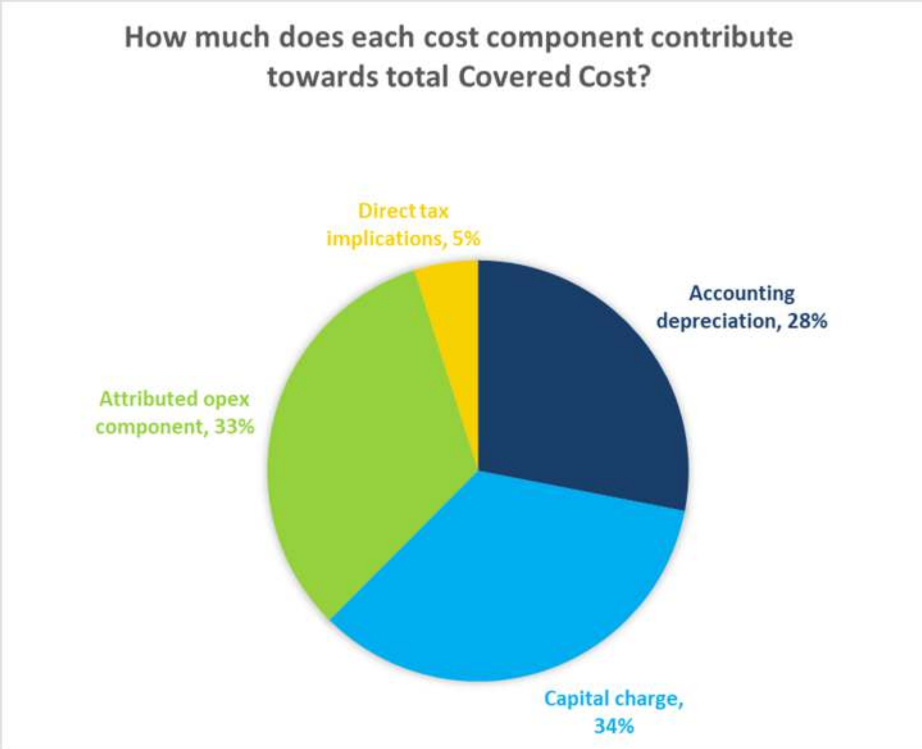

Figure 1 Pie chart to show the contribution of each cost component to covered cost

Calculate the BBCs for Schedule 1 BBIs

25. Transpower's proposal does not change the methodology that the Authority has used to calculate indicative prices for the Schedule 1 BBIs. The only adjustments to indicative prices for these BBIs we have made are:

    25.1 to update the covered cost to reflect our proposed approach for attributing opex to BBIs;

    25.2 to incorporate additional assets into the Bunnythorpe-Haywards reconductoring project BBI, to recognise the stage of this project that was commissioned during the 2019/20 financial year **($28.4m)**; [9]

    25.3 adjusting allocations to allow for the disconnection of one customer and three new customer connections that occurred over the year to April 2021 and therefore were not considered in the Schedule 1 allocations; and

    25.4 creating allocations for new customers based on comparable customers' allocations, applying the benefit factor method in clause 84(5) of the proposed TPM.

26. The total of BBCs for Schedule 1 BBIs is **$217.1m or 27%** of our recoverable revenue for the 2021/22 pricing year. These charges are allocated to customers on the basis of the customer allocations provided in Appendix A of the proposed TPM.

Calculate the BBCs for high-value post-2019 BBIs

27. There are no post-2019 BBIs that are >$20m for the 2021/2022 pricing year (i.e. no high-value post-2019 BBIs). Two case studies, provided in Appendix D (Clutha and Upper Waitaki

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[9] BPE-HAY was still inflight as at 30 June 2019 with work progressing on the final two sections. The Waikanae section was completed in the 2020/21 Financial Year noting that Indicative Pricing only includes commissioned assets to 30 June 2020.

Lines Project aka CUWLP) and Appendix E (Waikato and Upper North Island Voltage Management aka WUNIVM), have been developed to support understanding of how prices will be determined under the standard methods.

28. Once the new TPM is finalised we will be required to determine allocations and charges for any high-value post-2019 BBIs commissioned after July 2019. At the time of writing we have committed to the following high-value post-2019 BBIs: CUWLP and the Waikato dynamic reactive device (discussed in our case studies), the substation works for the Bombay-Otahuhu major capex project[10], and the HVDC Pole 2 converter transformer refurbishment project.[11]

Calculate the BBCs for low-value post-2019 BBIs

29. The proposed TPM would allocate covered costs associated with low-value post-2019 BBIs (<$20m) by applying the simple method.

30. The proposed simple method is explained in Chapter 7 (BBC Allocations). The simple method is necessarily a mechanical exercise because it is applicable to large number of lower value investments.

31. There are two key steps to calculating the simple method allocations once the regions have been determined. These are:

32. ***Regional Allocations:*** calculating regional net private benefit (**NPB**) for each connection region in respect of each investment region based on injection and offtake in the connection regions and electricity flows between the connection regions (clause 63 of the proposed TPM). This is performed by running five years of historical market generation, load and branch flow data based on circa 87,000 points in time. Total percentage allocation per region, split by customer group (injection and offtake), is shown in the Indicative Pricing workbook that accompanies the Proposal.

33. ***Customer Allocations:*** calculating individual customer NPBs by multiplying the relevant regional NPB by the customers' simple method factors for the relevant connection region, which are calculated from customers' intra-regional allocators for the connection region (clauses 62, 66(10) and 66(11) of the proposed TPM). The individual customer NPBs are then used to calculate customers' BBI customer allocations for the relevant BBI (clause 43(1) of the proposed TPM). Total percentage allocation by customer is broken down in Section 7 of this appendix.

34. Customers' BBCs for the low-value post-2019 BBI are then calculated by multiplying the covered cost of the BBI by the customers' BBC customer allocations (clause 36(2) of the proposed TPM).

4.4 Calculate the Residual charge

35. The residual charge is determined using recoverable revenue less other transmission charges to determine a residual revenue requirement.

36. The Anytime Maximum Demand (Residual) (**AMDR**) for each load customer at each location is determined based on historical meter data and aggregated across that Customer's points of connection.

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10 Bombay-Otahuhu Regional Investigation

11 HVDC Pole 2 Converter Transformer Refurbishment project

37. The residual charge rate is then determined by dividing the residual revenue requirement by the aggregated AMDR for all customers.
38. The residual charge rate is then applied to each load customer as the product of their individual AMDR and the residual charge rate.
39. Total indicative residual charges are **$449.2m or 56%** of total charges for the 2021/22 pricing year.

4.5 Calculate the Transitional Cap

40. The transitional cap is applied to certain load customers' residual charges and BBCs for the Schedule 1 BBIs.
41. The net impact of the transitional cap across all customers is nil as the reductions in some Customers' charges are funded by increased charges for other Customers (via transitional cap recovery charges).
42. The calculation used to determine the transitional cap and the associated explanations are detailed in Chapter 12 (Transitional Cap).
43. The total transitional cap adjustment by customer is broken down in Section 6 of this Appendix.

5 Indicative prices by charge type 2021/22

44. The chart below shows how the Model has indicatively apportioned Transpower's recoverable revenue under the proposed TPM- by charge type.

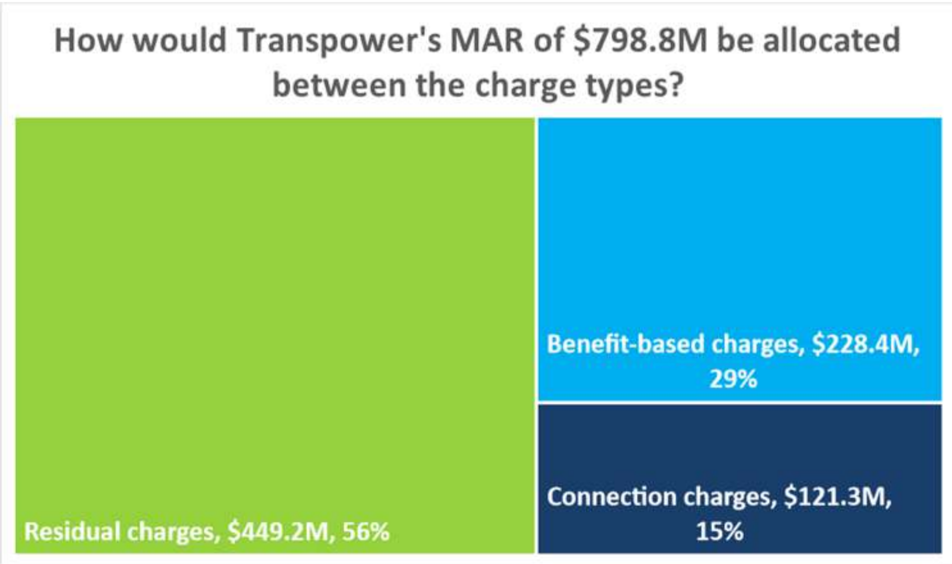


Figure 2 Allocation of Tranpsower's maximum allowable revenue (aka recoverable revenue) between charge types

45. The connection charge component is roughly the same as under current TPM and makes up 15% of recoverable revenue.
46. The BBC component makes up 29% of recoverable revenue.
47. The remaining 56% of recoverable revenue not captured by these charges is recovered using the residual charge.

48. Figure 3 below shows how the BBC component of the indicative pricing (shown above as 29% of recoverable revenue) is apportioned between different BBIs.

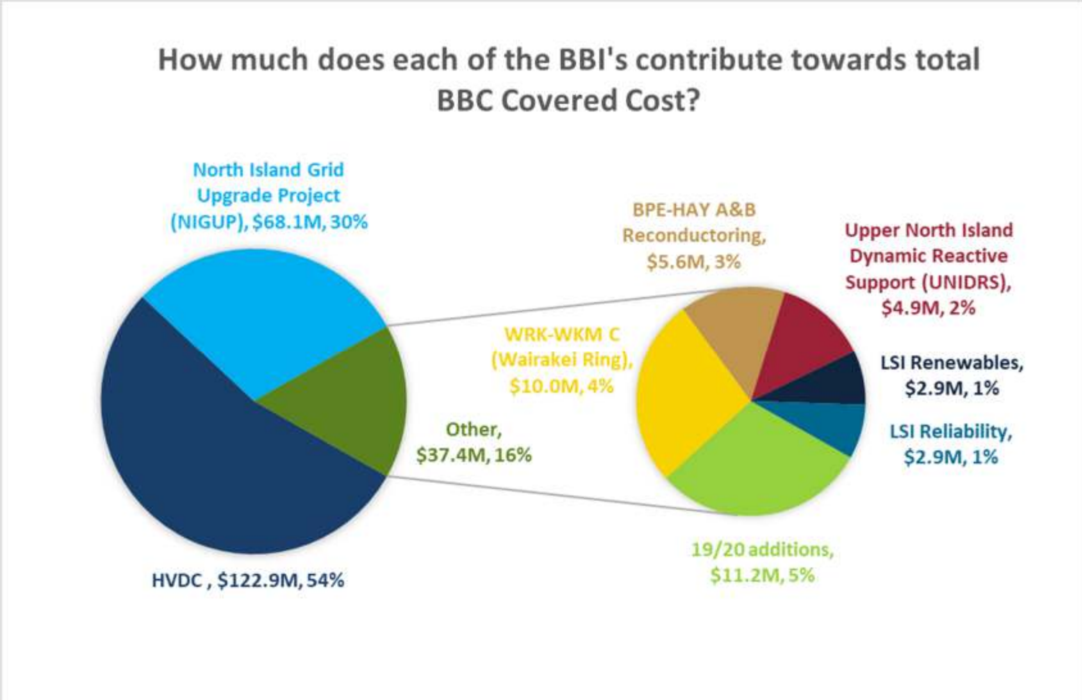


Figure 3 How the 29% of the MAR that comprises BBCs is allocated between BBIs

49. The BBC covered cost is attributed to a number of BBIs. Most of this cost is attributable to the HDVC (54%) and the North Island Grid Upgrade Project (30%). The remaining 16% is attributable to the other five Schedule 1 BBIs and the low-value post-2019 BBIs (referred to as the “19/20 additions”).

50. The 19/20 additions segment of the chart captures the BBC allocations made using the simple method and makes up 5% of the total BBC covered cost or only 1.4% of recoverable revenue. This result is due to the simple method applying only to post-2019 investments.

6 Indicative prices per customer 2021/22 by charge type

51. Table 2 below shows how Transpower's recoverable revenue is apportioned to each customer by charge type.

Table 2 Transpower's recoverable revenue apportioned to each customer by charge type

Customer name	Indicative prices ($m)	% of total charges	% of total charges (cum)	Connection charges	Benefit-based charges	Residual charges	Transitional cap adjustments	Schedule 1 Benefit-based charges	Simple Benefit-based charges
Vector Limited	179.9	22.5%	22.5%	13.2	55.7	108.2	2.9	54.1	1.6
Powerco Limited	81.3	10.2%	32.7%	16.0	10.9	53.2	1.1	10.1	0.8
Meridian Energy Limited	66.6	8.3%	41.0%	16.6	47.8	1.4	0.9	46.5	1.3
Orion New Zealand Limited	53.5	6.7%	47.7%	4.1	8.9	39.7	0.9	8.6	0.3
Wellington Electricity Lines Limited	46.3	5.8%	53.5%	8.2	7.6	29.8	0.7	6.8	0.9
NZ Aluminium Smelters Limited	44.7	5.6%	59.1%	1.3	12.4	30.3	0.8	12.2	0.2
Contact Energy Limited	29.8	3.7%	62.9%	4.2	23.8	1.4	0.4	22.7	1.1
Unison Networks Limited	27.0	3.4%	66.2%	5.6	2.2	18.8	0.4	1.9	0.3
Aurora Energy Limited	25.4	3.2%	69.4%	4.3	2.7	18.1	0.4	2.6	0.0
Powernet Ltd	22.3	2.8%	72.2%	3.8	2.9	15.3	0.3	2.8	0.1
WEL Networks Limited	20.0	2.5%	74.7%	1.7	2.7	15.3	0.3	2.6	0.1
Northpower Limited	18.3	2.3%	77.0%	2.5	6.5	9.0	0.3	6.2	0.4
Genesis Energy Ltd	14.5	1.8%	78.8%	5.0	8.7	0.7	0.1	7.5	1.2
Alpine Energy Ltd	12.6	1.6%	80.4%	2.6	1.6	8.2	0.2	1.6	0.0
Mainpower New Zealand Limited	12.1	1.5%	81.9%	2.9	1.6	7.5	0.2	1.6	0.1
Mercury NZ Limited	12.1	1.5%	83.4%	3.5	6.7	1.8	0.1	6.1	0.6
Counties Power Ltd	11.3	1.4%	84.8%	1.0	3.5	6.7	0.2	3.4	0.1
Network Tasman Limited	10.7	1.3%	86.2%	1.5	1.4	7.7	0.2	1.3	0.1
EA Networks	10.7	1.3%	87.5%	0.3	1.0	9.2	0.2	1.0	0.0
New Zealand Steel Limited	10.0	1.2%	88.8%	2.3	2.7	8.8	(3.8)	2.6	0.0
Electra Limited	9.0	1.1%	89.9%	1.6	1.5	5.8	0.1	1.4	0.1
Horizon Energy Distribution Ltd	7.7	1.0%	90.8%	2.4	0.4	4.8	0.1	0.4	0.0
Waipa Networks Limited	6.3	0.8%	91.6%	1.2	1.2	3.9	0.1	1.1	0.1
The Lines Company Ltd	6.1	0.8%	92.4%	1.4	0.7	3.9	0.1	0.7	0.0
Top Energy Ltd	5.9	0.7%	93.1%	1.0	1.2	3.6	0.1	1.1	0.1
Marlborough Lines Limited	5.4	0.7%	93.8%	0.6	1.0	3.8	0.1	0.9	0.1
Network Waitaki Limited	5.3	0.7%	94.5%	0.9	0.7	3.6	0.1	0.7	0.0
Pan Pac Forest Product Limited	4.2	0.5%	95.0%	1.0	0.8	4.1	(1.7)	0.7	0.0
Eastland Network Limited	4.0	0.5%	95.5%	0.3	0.6	3.1	0.1	0.2	0.4
Westpower Limited	4.1	0.5%	96.0%	0.7	0.2	3.1	0.1	0.5	(0.3)
Norske Skog Tasman Limited	3.8	0.5%	96.5%	1.2	0.5	6.4	(4.2)	0.4	0.1
Winstone Pulp International	3.5	0.4%	96.9%	1.1	0.5	1.9	0.0	0.3	0.2
KiwiRail Holdings Limited	3.5	0.4%	97.4%	2.0	0.3	2.2	(0.9)	0.4	(0.2)
Nga Awa Purua Joint Venture	2.5	0.3%	97.7%	0.4	1.7	0.3	0.0	1.5	0.2
Centralines Limited	2.2	0.3%	98.0%	0.8	0.4	1.1	0.0	0.3	0.1
Trustpower Limited	2.0	0.2%	98.2%	0.8	1.1	0.0	0.0	1.0	0.1
Scanpower Limited	1.7	0.2%	98.4%	0.6	0.3	0.8	0.0	0.2	0.0
Ngatamariki Geothermal Ltd	1.4	0.2%	98.6%	0.3	1.0	0.0	0.0	0.1	0.9
Buller Electricity Ltd	1.6	0.2%	98.8%	0.5	0.1	1.0	0.0	0.9	(0.8)
OMV New Zealand Production Ltd	1.1	0.1%	98.9%	0.3	0.2	0.6	0.0	0.2	0.0
Todd Generation Taranaki Limited	1.0	0.1%	99.1%	0.1	0.8	0.1	0.0	0.6	0.2
Nelson Electricity Ltd	0.9	0.1%	99.2%	0.1	0.1	0.7	0.0	0.1	0.0
Whareroa Cogeneration Limited	0.9	0.1%	99.3%	0.2	0.1	1.6	(0.9)	0.1	0.0
Methanex New Zealand Ltd	0.9	0.1%	99.4%	0.2	0.1	0.5	0.0	0.1	0.0
Daiken Southland Limited	0.8	0.1%	99.5%	0.2	0.2	0.5	0.0	0.2	0.0
Nova Energy Limited	0.7	0.1%	99.6%	0.3	0.1	0.4	0.0	0.0	0.0
Beach Energy Resources NZ (Holdings) Ltd	0.7	0.1%	99.7%	0.1	0.2	0.5	0.0	0.1	0.0
Southern Generation GP Limited	0.2	0.0%	99.7%	0.2	0.0	-	-	0.2	(0.2)
MEL (West Wind) Limited	0.6	0.1%	99.8%	0.1	0.4	0.1	0.0	0.2	0.2
Mercury SPV Limited	0.6	0.1%	99.9%	0.1	0.4	0.1	0.0	0.1	0.2
Waverley Wind Farm	0.4	0.0%	99.9%	0.1	0.2	0.1	0.0	0.1	0.1
Tararua Wind Power	0.3	0.0%	99.9%	0.1	0.2	0.1	0.0	0.1	0.1
MEL (Te Apiti) Limited	0.3	0.0%	100.0%	0.1	0.2	0.0	0.0	-	0.2
Southdown Cogeneration Ltd	0.2	0.0%	100.0%	0.0	0.0	0.1	0.0	0.0	0.0
Southpark Utilities Limited	0.0	0.0%	100.0%	0.0	0.0	0.0	0.0	-	0.0
GTL Energy New Zealand Ltd	0.0	0.0%	100.0%	0.0	0.0	0.0	(0.0)	0.0	0.0
Total	**798.9**			**121.3**	**228.4**	**449.2**	**0.0**	**217.1**	**11.2**
Lines Business	591.5	74.0%	74.0%	79.7	117.4	385.5	8.9	112.1	6.2
Generator	133.1	16.7%	90.7%	31.8	93.2	6.5	1.7	87.8	4.5
Direct Connect	74.2	9.3%	100.0%	9.8	17.8	57.2	(10.6)	17.2	0.5
Total	**798.9**			**121.3**	**228.4**	**449.2**	**0.0**	**217.1**	**11.2**

52. The three graphs in figure 4 below show the total indicative charge each customer would pay under the proposed TPM for the 2021/2022 period. A customer's total charge is shown by the number to the right.

53. Customers are grouped by the quantum of their total charge:

    53.1 charges totalling >$ 40m;

    53.2 charges between $5m – $40m, and

    53.3 charges< $5m.

54. Generally speaking, BBCs are a more significant proportion of generators' total charges compared to distributors and direct consumers.

55. The majority of customers have small, positive Transitional Cap adjustments while a few have relatively large negative Transitional Cap adjustments. These few customers' allocated charges under the proposed TPM would exceed the transitional cap so their charges are decreased by the amount in the yellow bar and these costs are then distributed amongst, and recovered from, the rest of Transpower's customers.

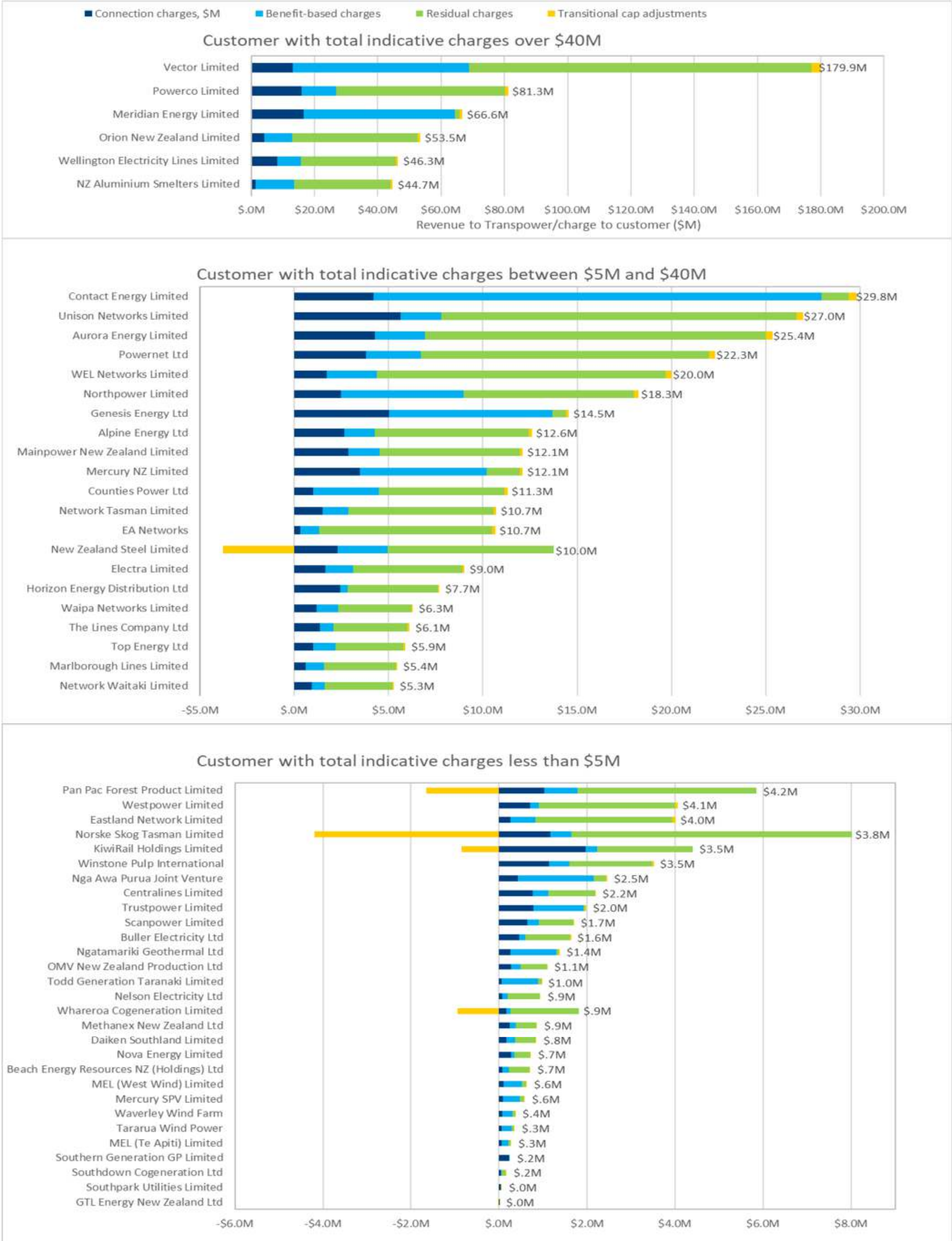


Figure 4 Customer charges by charge type, for charges totalling > 40m, between $5m – 40m, and < $5m.

7 Indicative total charges compared with status quo charges

56. Table 3 and figures 6 and 7 below show how the indicative charges for the 20/21 pricing year compare with the status quo i.e. the charges our customers have received for the current pricing year

Table 3 Indicative total charges compared with the status quo

Customer	Status Quo ($m pa)	Proposed ($m pa)	$ Change ($m pa)	% Change
Vector Limited	172.11	179.89	7.78	5%
Powerco Limited	92.21	81.28	-10.92	-12%
Meridian Energy Limited	80.94	66.63	-14.31	-18%
Orion New Zealand Limited	61.60	53.50	-8.10	-13%
Wellington Electricity Lines Limited	54.37	46.27	-8.11	-15%
NZ Aluminium Smelters Limited	58.32	44.70	-13.62	-23%
Contact Energy Limited	24.56	29.82	5.26	21%
Unison Networks Limited	29.84	26.98	-2.86	-10%
Aurora Energy Limited	22.12	25.37	3.26	15%
Powernet Ltd	24.32	22.32	-2.00	-8%
WEL Networks Limited	19.94	20.00	0.06	0%
Northpower Limited	16.34	18.25	1.92	12%
Genesis Energy Ltd	10.26	14.53	4.27	42%
Alpine Energy Ltd	12.31	12.61	0.31	2%
Mainpower New Zealand Limited	12.31	12.12	-0.20	-2%
Mercury NZ Limited	3.48	12.11	8.63	248%
Counties Power Ltd	10.96	11.31	0.34	3%
Network Tasman Limited	11.82	10.71	-1.11	-9%
EA Networks	4.56	10.65	6.10	134%
New Zealand Steel Limited	3.13	9.98	6.85	219%
Electra Limited	7.51	9.02	1.51	20%
Horizon Energy Distribution Ltd	3.49	7.69	4.20	120%
Waipa Networks Limited	7.69	6.29	-1.40	-18%
The Lines Company Ltd	4.74	6.09	1.35	28%
Top Energy Ltd	4.93	5.88	0.95	19%
Marlborough Lines Limited	6.66	5.45	-1.21	-18%
Network Waitaki Limited	4.23	5.28	1.05	25%
Pan Pac Forest Product Limited	2.77	4.20	1.42	51%
Eastland Network Limited	5.49	4.01	-1.49	-27%
Westpower Limited	2.04	4.06	2.01	99%
Norske Skog Tasman Limited	1.17	3.82	2.66	228%
Winstone Pulp International	3.35	3.52	0.18	5%
KiwiRail Holdings Limited	2.85	3.54	0.69	24%
Nga Awa Purua Joint Venture	0.43	2.47	2.04	478%
Centralines Limited	2.65	2.20	-0.45	-17%
Trustpower Limited	4.49	1.98	-2.51	-56%
Scanpower Limited	1.92	1.70	-0.21	-11%
Ngatamariki Geothermal Ltd	0.26	1.37	1.11	428%
Buller Electricity Ltd	0.55	1.64	1.09	197%
OMV New Zealand Production Ltd	1.25	1.10	-0.15	-12%
Todd Generation Taranaki Limited	0.06	0.98	0.91	1407%
Nelson Electricity Ltd	1.04	0.94	-0.10	-10%
Whareroa Cogeneration Limited	0.17	0.88	0.71	428%
Methanex New Zealand Ltd	0.75	0.86	0.11	15%
Daiken Southland Limited	0.79	0.84	0.05	7%
Nova Energy Limited	0.28	0.71	0.44	157%
Beach Energy Resources NZ (Holdings) Ltd	0.88	0.70	-0.18	-21%
Southern Generation GP Limited	0.24	0.23	-0.01	-5%
MEL (West Wind) Limited	0.12	0.62	0.51	439%
Mercury SPV Limited	0.08	0.57	0.49	616%
Waverley Wind Farm	0.07	0.36	0.29	394%
Tararua Wind Power	0.07	0.34	0.28	413%
MEL (Te Apiti) Limited	0.07	0.27	0.19	267%
Southdown Cogeneration Ltd	0.06	0.15	0.09	143%
Southpark Utilities Limited	0.04	0.05	0.00	9%
GTL Energy New Zealand Ltd	0.01	0.01	0.00	85%

57. Figures 5 and figure 6 below show the above information in graph form, in dollar (figure 5) and percentage (figure 6) terms

Figure 5 Indicative charges v status quo in dollar terms, for pricing year 20/21 (the current pricing year)

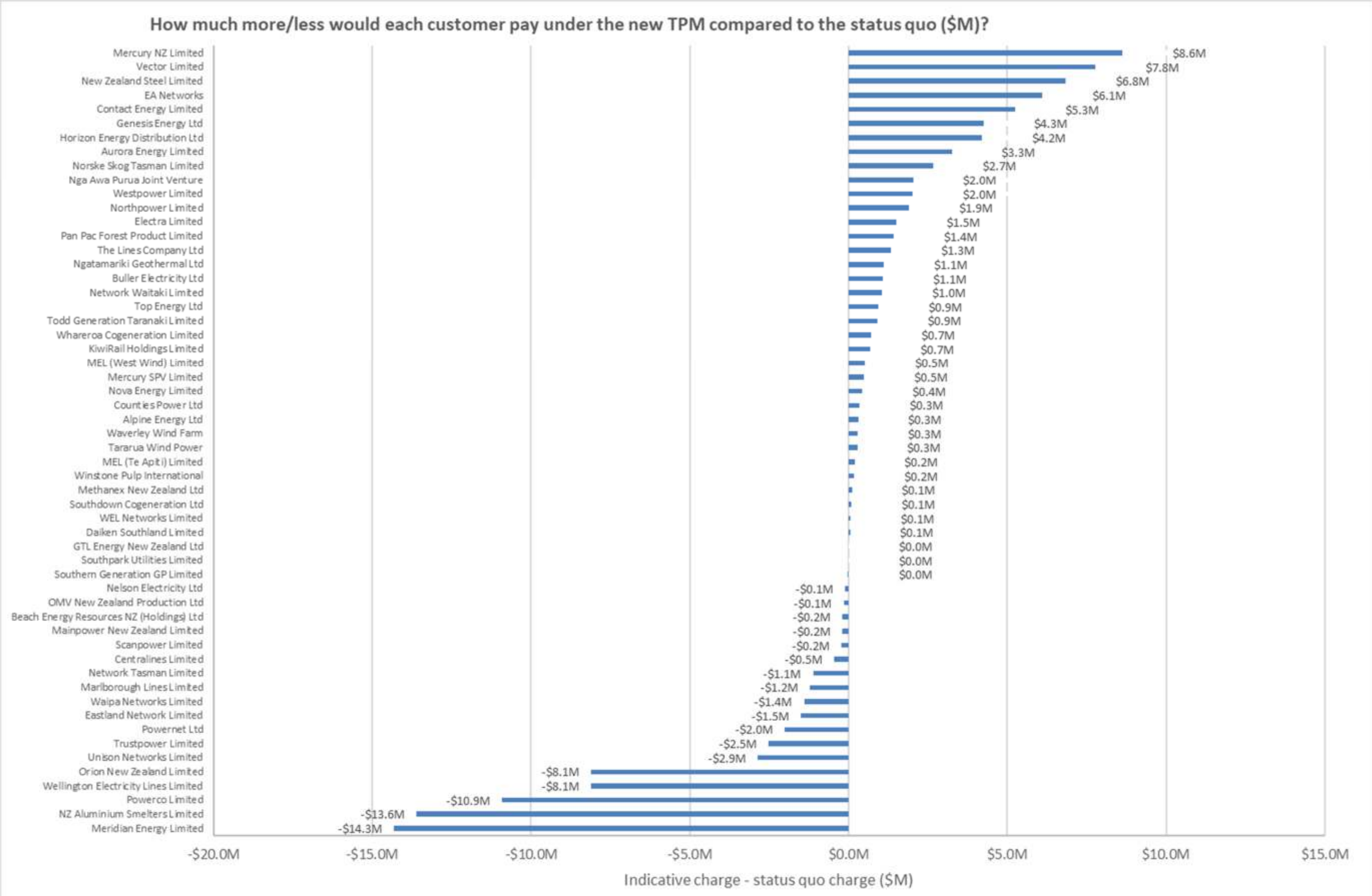
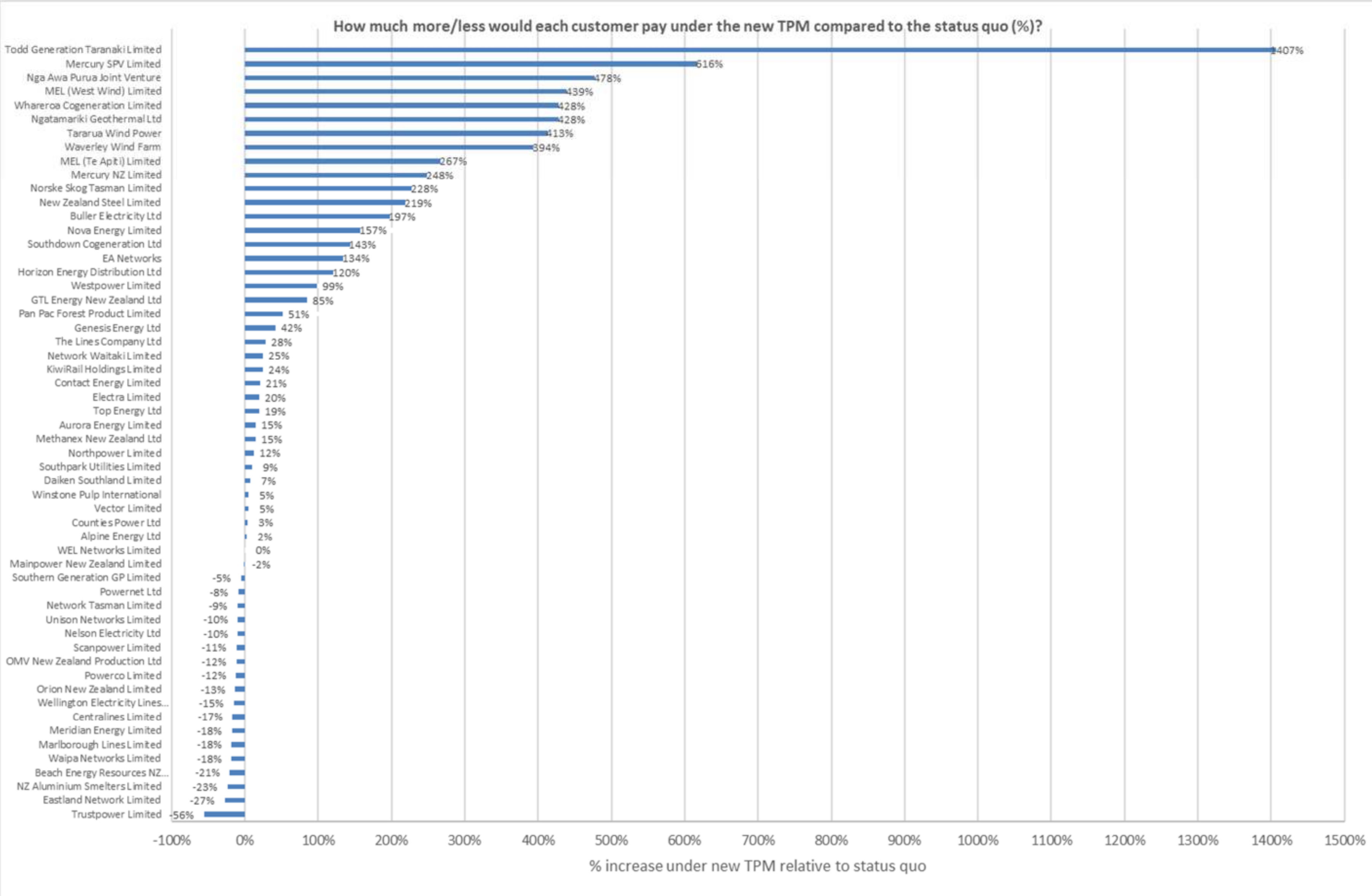


Figure 6 Indicative charges v status quo in percentage terms, for pricing year 20/21 (the current pricing year)



8 Projecting Indicative Prices to 2035

58. In this final section, we attempt to signal how charges may evolve under the TPM proposal. The period for our projection is arbitrary, but sufficient in length to signal the key implications of the proposed TPM, and is set to the 2034/2035 pricing year.
59. Indicative prices for 2021/22 alone cannot reveal the impact of the BBC over time.
60. All other existing investments in the interconnected grid are recovered over time from load customers via the residual charge. Eventually these investments will be decommissioned, fully depreciated or replaced with BBIs. The result will be a gradual reduction in the share of our recoverable revenue collected from load customers as residual charges, offset by a larger attribution to both load and generation customers as BBCs.
61. For the purposes of projecting charges under the proposed TPM, we have made the following assumptions:
    61.1 Investment forecasts are based on Transpower's high-level investment thinking; and
    61.2 Connection charges remain constant as a proportion of Recoverable Revenue.
62. For the purposes of projecting indicative prices out to 2034/2035 we have simplified our analysis and assumed post 2020/21 investments in the interconnected grid are depreciated using the same depreciation profile as the 2019/20 year. Actual pricing will be based on the relevant depreciation rate for each type of asset.
63. It is not practicable to project indicative prices to customer level given lack of granular forecast information and very high degrees of uncertainty over the timeline including where we will invest in what and to the benefit of which of our customers.
64. The following projected indicative prices (by charge type) for the period 2023/24 to 2034/35 pricing year are therefore highly uncertain and provided only to demonstrate the directional shift in how our recoverable revenue is likely to be allocated between charge types over time. This is shown in the chart (figure 7) below:
65. As more BBIs are made, a growing proportion of recoverable revenue will be recovered through BBCs. This is shown by the growth in the proportions attributed to Post 2020 investment BBC >$20M and <$20M over the forecast period
66. The proportion of recoverable revenue attributable to Schedule 1 BBIs will also decline over time as these assets depreciate.

67. As a result of a growing proportion of recoverable revenue being attributed to BBCs, the remaining pool of revenue to be recovered by the residual charge falls, leading to a decline in the proportion of the residual charge over the period.

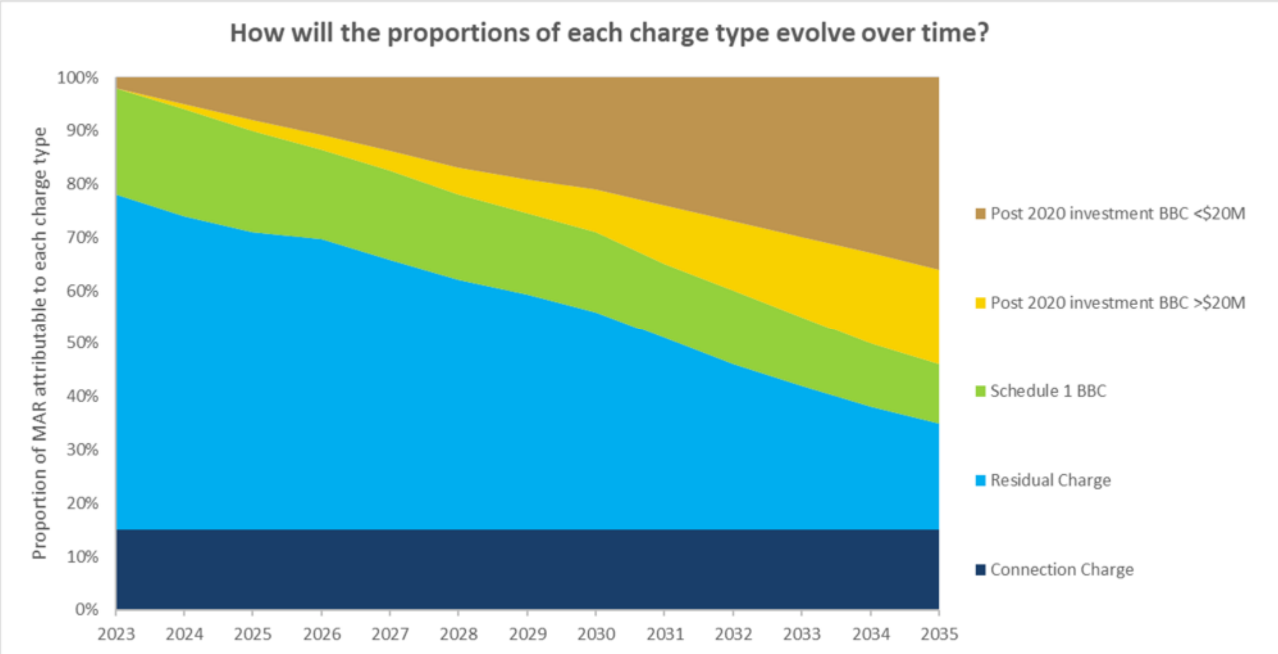


Figure 7 Projection to 2035 of how the proportion of each charge type to recoverable revenue might change