TRANSPOWER

HVDC Link Upgrade Programme Major Capex Proposal (Stage 1)

Attachment 9: TPM and Indicative Pricing Impacts

September 2025

Purpose

Under the transmission pricing methodology (**TPM**),[1] the covered costs[2] of post-2019 investments in interconnection assets and interconnection transmission alternatives (post-2019 benefit-based investments or **BBIs**) are recovered from customers identified as beneficiaries. These allocations are based on each customer's expected positive net private benefit (**NPB**) from those investments. The charges through which the covered costs are recovered are called benefit-based charges or **BBCs**. The TPM contains the methods for calculating BBCs.

This document presents information to the Commerce Commission (**Commission**) and other stakeholders about the indicative increase in transmission charges (specifically indicative BBCs) due to the proposed Stage 1 investment for the HVDC Link Upgrade Programme. This document includes indicative starting allocations and indicative covered costs for the HVDC Link Upgrade Stage 1 BBI, from which we have calculated indicative BBCs.

Following the Commission's final decision, we will undertake a formal consultation on the proposed starting allocations for the BBI, which will be a high-value BBI,[3] as required by the TPM.

We have used the methodologies in the TPM and Assumptions Book[4] to produce the indicative allocations in this document. However, our calculations have not been at the level of detail we will apply when we calculate proposed starting allocations for the HVDC Link Upgrade Programme Stage 1 BBI for consultation under the TPM (as noted above, this will be after the Commission's final decision). Nevertheless, we consider the indicative starting allocations presented in this document provide a reasonable indication of the distribution of NPB from the BBI using the modelling inputs and assumptions set out in this document (which themselves are indicative only).

We emphasise that the indicative starting allocations, covered costs and BBCs in this document are not the proposed or final starting allocations, covered costs or BBCs for the HVDC Link Upgrade Stage 1 BBI. Transpower cannot, and does not, accept any liability for the accuracy or completeness of the information provided, nor for any consequences arising from any party's reliance on it. We strongly recommend that stakeholders review the TPM and Assumptions Book themselves and seek independent expert advice before relying on any information in this document.

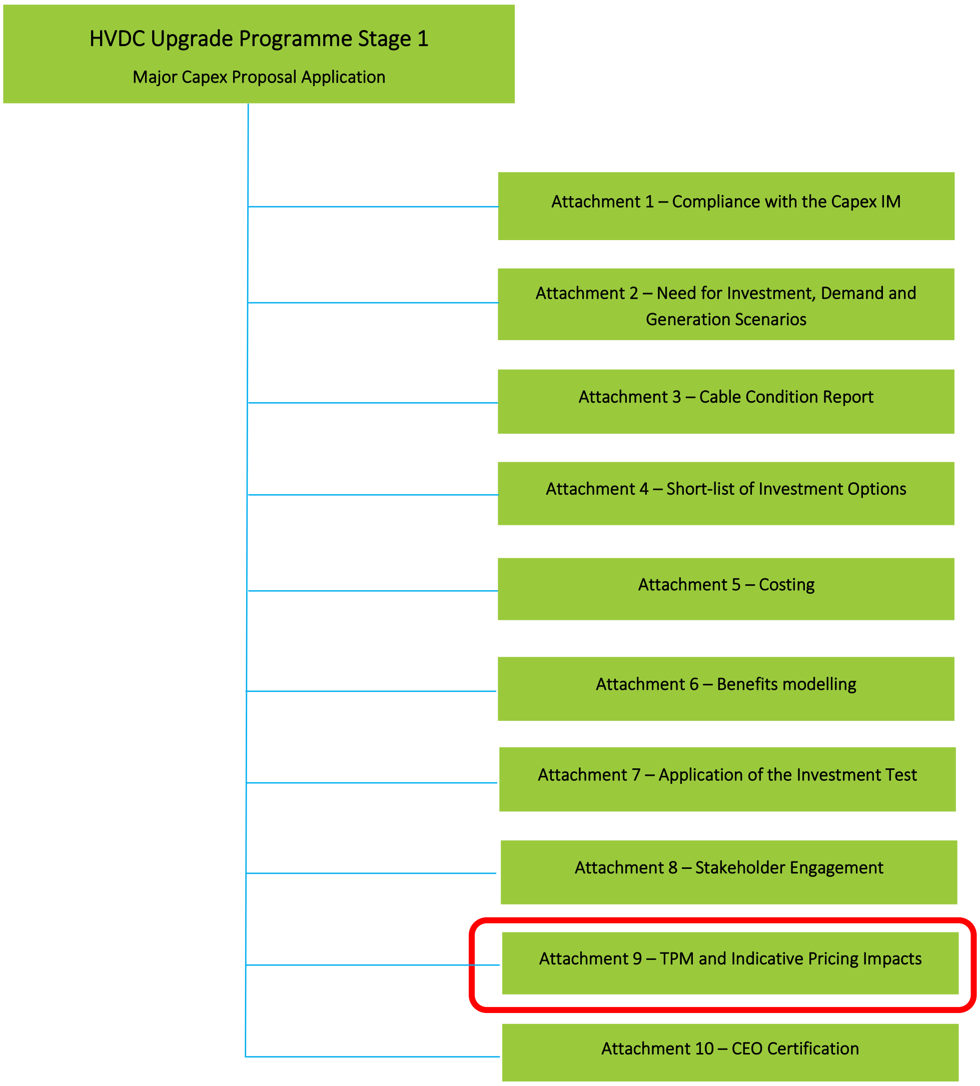
Unless otherwise stated, all clause references in this document refer to clauses within the TPM.

1 The TPM is in Schedule 12.4 of Part 12 of the Electricity Industry Participation code 2010.

2 The cost recovered through the benefit-based charges for a benefit-based investment is referred to in the TPM as the 'covered cost'.

3 A high-value BBI is a BBI that is expected to involve capital expenditure and/or transmission alternative operating expenditure of more than the base capex threshold under the Capex IM, which is $30m for projects notified to the Commission after 1 April 2025.

4 The Assumptions Book contains detail about how the methodologies in the TPM for calculating and adjusting BBC allocations are applied.


HVDC Upgrade Programme Stage 1
Major Capex Proposal Application
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Contents

1 Background

1.1 Investments comprising the proposed Stage 1 investment

The investments that comprise the proposed Stage 1 investment for the HVDC Link Upgrade Programme are:

i. Supply and installation of submarine cables to support 1400 MW ($760.4m)

ii. Cable termination station replacement ($134.5m)

iii. Benmore filter bank upgrade to enable 1400 MW ($19.7m)

iv. Pole 2 overload scheme ($12.7m)

v. Establishment of new submarine cable storage facility ($11.6m).

The proposed Stage 1 investment, which has an expected cost of $978.1 million,[5] will be a high-value post-2019 BBI because it is an interconnection investment, will be commissioned after 23 July 2019,[6] and is forecast to cost more than $30m (being the base capex threshold under the *Transpower Capital Expenditure Input Methodology Determination* (**Capex IM**)). The proposed Stage 1 investment is expected to be completed and commissioned by December 2031.

The Assumptions Book, at paragraph 259, describes when it may be necessary to break a project into more than one BBI. We have assessed the individual investments that comprise the proposed Stage 1 investment against the criteria in paragraph 259 of the Assumptions Book and determined they should be treated as a single BBI because the investments are occurring in the same area of the grid and address a single need, namely replacing key components of the HVDC due to them becoming end of life. In this document we call this BBI the **HVDC Link Upgrade Stage 1 BBI**.

The HVDC Link Upgrade Stage 1 BBI is a high-value post-2019 BBI. Under the TPM, Transpower must use a standard method under the TPM to determine its beneficiary customers and calculate their starting allocations.

We have used the price-quantity method[7] for the HVDC Link Upgrade Stage 1 BBI. The price-quantity method must be used for all high-value post-2019 BBIs that are not resiliency BBIs. There are no material resiliency risks being mitigated by the proposed Stage 1 investment.

Within the price-quantity method there are four types of regional net private benefit (**NPB**) that may be calculated – market regional NPB, ancillary service regional NPB, reliability regional NPB and other regional NPB.

For the HVDC Link Upgrade Stage 1 BBI, we have calculated market regional NPB only (regional NPB relating to changes in quantities and prices in the wholesale electricity market). This is

5 This value includes project investigation costs ($19.5m) and Stage 2 preparatory costs ($19.6m).
6 23 July 2019 is the date the TPM uses to distinguish between pre- and post-2019.
7 The price-quantity method is detailed in clauses 44 to 55 of the TPM.

because we expect most of the benefits of the HVDC Link Upgrade Stage 1 BBI to be derived from market benefit.

Within the price-quantity method there are two options for calculating market regional NPB arising from changes in the wholesale market for electricity. The default option is to calculate market regional NPB based on quantities during periods of benefit (clause 51). The alternative option uses both quantities and prices to calculate market regional NPB (clause 52).

We have used the quantity and price-based option (clause 52) to calculate the indicative starting allocations and BBCs for the HVDC Link Upgrade Stage 1 BBI because using the clause 51 method would not produce allocations that are broadly proportionate to positive NPB from the BBI without introducing a subjective price differential threshold to identify periods of benefit.

1.2 Interaction with the Capex IM

The combined investment value of the HVDC Link Upgrade Programme is estimated at $1475.5 million, to be delivered in stages, and the overall nature of the investment is enhancement. This means the investment is a major capex project (staged) under the Capex IM, and Transpower must submit an MCP to the Commission for each stage seeking approval to recover the costs from Transpower customers. The proposed Stage 1 investment is the first stage of the HVDC Link Upgrade Programme.

Under the Capex IM, an MCP must include information about the expected increase in transmission charges due to the proposed expenditure. We have included this for the proposed Stage 1 investment and explained our methodology in section 4.

The MCP also includes the generation and demand scenarios and other modelling assumptions and parameters we use to apply the Capex IM investment test (**Investment Test**). Clause 43(5) of the TPM generally requires consistency in approach with the Investment Test when we calculate starting allocations for a high-value post-2019 BBI. We may depart from the Investment Test approach if we determine that approach would not produce allocations that are broadly proportionate to NPB from the BBI. Refer to section 3.1 for more details.

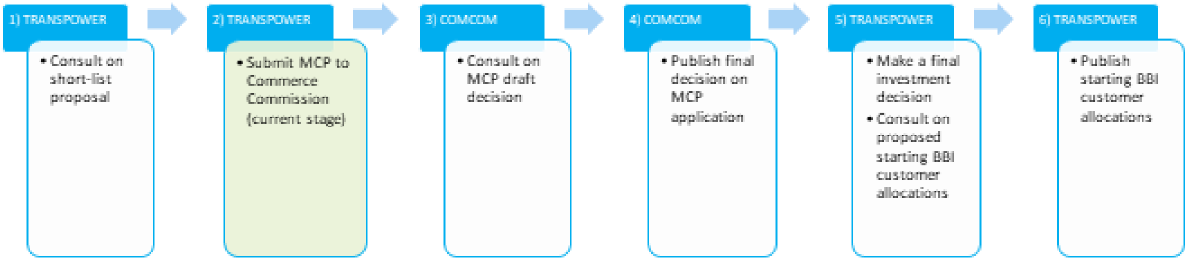
1.3 What happens next?

Under clause 15 of the TPM, Transpower must consult on the proposed starting allocations for each high-value post-2019 BBI.

Assuming the Commission approves the proposed Stage 1 investment, Transpower will make its final investment decision – whether to proceed with the investment. If we decide to proceed, we will consult on the proposed starting allocations for the HVDC Link Upgrade Stage 1 BBI under the TPM. After considering submissions in response to that consultation, we will finalise the starting allocations and publish them.

These planned stages are illustrated in Figure 1 below.

Figure 1: Planned stages up to publishing starting allocations



2 Indicative covered costs of the HVDC Upgrade Stage 1 BBI

This section summarises the assumptions used in calculating the indicative covered costs for the HVDC Link Upgrade Stage 1 BBI and provides the results of those calculations.

2.1 TPM requirements for calculating covered cost

The cost recovered through the BBCs for a BBI is referred to in the TPM as the BBI's 'covered cost'.[8]

Under the TPM, a BBI's covered cost is calculated annually based on the values of certain capex and opex inputs for the relevant pricing year. A BBI's covered cost is made up of:

- costs that are directly attributable to the BBI or have a verifiable causal relationship with it. This captures capex costs (depreciation and a return on investment using our regulated WACC) and some types of opex; and
- a portion of our "overhead" opex, which does not have a direct or causal relationship with the BBI but is reasonably attributable to it. This type of opex is attributed to all BBIs in proportion to their depreciation (depreciation multiplied by an attributed opex ratio).

2.2 Indicative covered costs

We have used the same cost estimates as in Attachment 5 to calculate the indicative covered costs for the HVDC Link Upgrade Stage 1 BBI.

The annual covered cost of a BBI is confirmed as part of calculating transmission charges for each pricing year after the BBI is commissioned. Our calculation of the HVDC Link Upgrade Stage 1 BBI's indicative covered cost relies on a number of estimates including final asset composition and asset values, which we will not know until after the BBI is fully commissioned.

While this MCP does not seek approval for operating and maintenance expenditure, we have estimated the opex reasonably attributable to the investment as part of our indicative covered cost. This opex will be recovered through our base expenditure allowances approved for each regulatory control period (**RCP**) and allocated under the TPM as appropriate.

8 For more information see also Transpower's TPM Information Sheet - BBC Covered Cost v2.pdf.

Figure 2: HVDC Link Upgrade Stage 1 BBI indicative covered costs

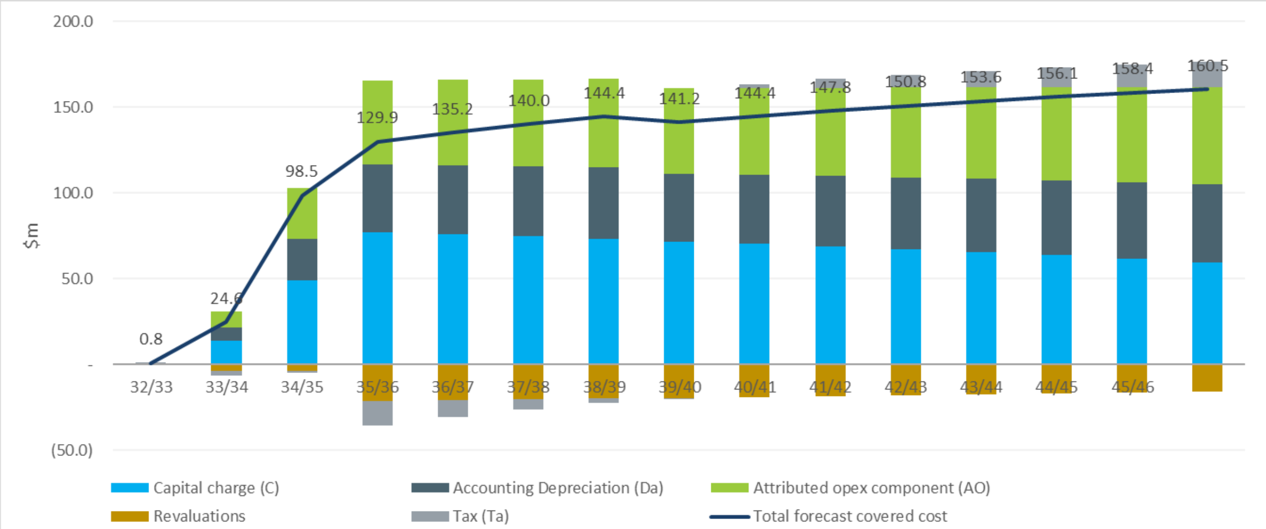


Table 1: HVDC Link Upgrade Stage 1 BBI indicative covered costs ($million, nominal)

Pricing year, PY (starting 1 April)	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39	39/40	40/41	41/42	42/43	43/44	44/45	45/46
Accounting Depreciation (Da)	-	7.6	24.0	39.1	39.9	40.7	41.5	39.7	40.3	41.1	41.9	42.8	43.6	44.5	45.4
Capital charge (C)	0.6	14.0	49.2	77.3	76.0	74.6	73.2	71.6	70.2	68.7	67.1	65.4	63.6	61.7	59.7
Revaluations	-	(3.7)	(3.8)	(21.0)	(20.6)	(20.2)	(19.8)	(19.4)	(19.0)	(18.5)	(18.1)	(17.6)	(17.0)	(16.5)	(15.9)
Attributed opex component (AO)	-	9.4	29.9	48.9	49.9	50.9	51.9	49.6	50.4	51.4	52.4	53.4	54.5	55.6	56.7
Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	0.2	(2.8)	(0.7)	(14.4)	(9.9)	(6.0)	(2.4)	(0.2)	2.6	5.2	7.5	9.6	11.4	13.1	14.6
Total forecast covered cost	0.8	24.6	98.5	129.9	135.2	140.0	144.4	141.2	144.4	147.8	150.8	153.6	156.1	158.4	160.5

Some key assumptions and inputs we have applied to calculate the BBI's indicative covered cost are as follows:

- The accounting and tax depreciation rates used are the weighted average of forecast assets commissioned;
- Vanilla WACC (7.10%), cost of debt (5.74%) and leverage (41%) approved for RCP4[9] are used in the calculation for all later RCPs;
- The attributable opex ratio for RCP4 is used in the calculation for all later RCPs;

The BBCs for the HVDC Link Upgrade Stage 1 BBI will continue after pricing year 2045/46. Figure 2 and Table 1 stop at pricing year 2045/46 because we expect the BBI's covered cost to peak in that pricing year.

9 RCP4 is Transpower's fourth regulatory control period under Part 4 of the Commerce Act 1986. RCP4 is the period from 1 April 2025 to 31 March 2030.

3 Indicative starting allocations

This section summarises our application of the price-quantity method in the TPM to calculate indicative starting allocations for the HVDC Link Upgrade Stage 1 BBI.

3.1 Market scenarios and other key modelling assumptions

These indicative starting allocations primarily use the modelling assumptions and inputs from the HVDC Link Upgrade Programme Investment Test, which are generally consistent with chapter 2 of our Assumptions Book.

The counterfactual and factual scenarios are as follows:

- The counterfactual is no investment being made, i.e. the Base Case (Option 1) which assumes that the HVDC is decommissioned in 2038 without any of the HVDC investments implemented;
- The factual is the proposed Stage 1 investment which involves upgrades of the HVDC and the HVDC north transfer capacity being increased to 1400 MW.

3.2 Modelled regions and market regional NPB

3.2.1 Modelled regions

Following the process in section 3.3.6.9 of the Assumptions Book, we define the following modelled regions for our indicative starting allocations:

a. North Island (NI),

b. South Island (SI).

Modelled regions are identified by grouping GXP/GIPs that experience similar changes in price or quantity due to the alleviation of system constraints.

3.2.2 Market regional NPB

We have calculated market regional NPB based on the modelled change in consumer and producer benefit in the wholesale market for electricity.

At this stage we have not included the modelled change in loss and constraint excess received by customers as required under clauses 52(3) and 52(4) of the TPM. We will consider including this when we consult on the proposed starting allocations following Commission approval of the investment.

For customers with injection and offtake at the same connection location, we net off the customer's expected market disbenefit from its injection or offtake at the connection location against the customer's expected market benefit from its offtake or injection at the connection location.

Without the HVDC Link Upgrade Stage 1 BBI, energy flow between the North Island and South Island would be reduced, and cease completely following decommissioning of the HVDC link. Without the investment there would be significant constraints on the export of energy out of the South Island and on the import of energy into the South Island, depending on the climate and season.

This HVDC Link Upgrade Stage 1 BBI is expected to deliver market benefits primarily to load in the North Island and generation in the South Island. This is because North Island load does not have to pay elevated energy prices due to the inability to transfer energy from the South Island, and upstream generation in the South Island does not get paid suppressed energy prices.

The HVDC Link Upgrade Stage 1 BBI also offers small benefits to North Island generators. Without the HVDC some North Island wind would receive reduced prices due to a high regional concentration and coincident generation output.

Note that South Island load benefits when the HVDC flow is north to south, such as during a dry period. However, the indicative starting allocations are based on <u>*net*</u> private benefits; South Island load *dis*benefits (from south to north flows) outweigh the north to south flow benefits, so the allocation is made to South Island generators and North Island load.

We have grouped regional customer groups in accordance with the approach to finalising regional customer groups in section 3.3.6.13 of the Assumptions Book.

The following table shows the indicative allocations of regional NPB to regional customer groups for the HVDC Link Upgrade Stage 1 BBI.

Table 2: Indicative allocations of positive regional NPB to regional customer groups

Indicative regional customer group	Indicative regional NPB share
South Island Hydro Generation[10]	53%
North Island Non-Industrial Load (EDBs)	45%
North Island Industrial Load	1%
North Island Load with Generation[11]	1%
NI Wind, NI Commitment Thermal, and NI Cogen Generation	Less than 0.1%

Generator groups and South Island load customers not listed in Table 2 have a negative (indicative) NPB from the investment and therefore are not allocated any costs in this estimation.

3.2.3 Individual NPB

To calculate individual NPBs for the purpose of indicative starting allocations we used the intra-regional allocators for each benefitting customer based on their mean historical annual injection and mean historical annual offtake (as appropriate) from 1 September 2019 to 31

10 The South Island Hydro Generation regional customer group is formed by the amalgamation of both storage and run-of-river customer groups. The process for finalising regional customer groups is described in section 3.3.6.13 of the Assumptions Book.

11 "Load with generation" and "generation with load" customer groups are formed when the NPB of customer/location's offtake and injection volumes have similar magnitude. As with all regional customer groups, the intent is to ensure that cost allocations remain proportionate to each customer's positive net private benefit (NPB).

August 2024. This calculation will be updated for more recent years' offtake and injection after there is a final investment decision date for the proposed Stage 1 investment and prior to consulting on the proposed starting allocations for the HVDC Link Upgrade Stage 1 BBI under the TPM.

3.2.4 Indicative starting allocations

As required under the TPM, we calculated each benefitting customer's indicative starting allocation for the HVDC Link Upgrade Stage 1 BBI as the customer's individual NPB divided by the sum of all benefitting customers' individual NPBs. This results in the following indicative starting allocations (to two decimal places).

Table 3: Indicative starting allocations

Customer Code	Customer Name	Indicative starting allocation (%)
MERI	Meridian Energy Ltd	37%
VECT	Vector Ltd	18%
CTCT	Contact Energy Ltd	11%
POCO	Powerco Ltd	10%
UNET	Wellington Electricity Lines Ltd	5%
GENE	Genesis Energy Ltd	3%
UNIS	Unison Networks Ltd	3%
WELE	WEL Networks Ltd	2%
NPOW	Northpower Ltd	2%
COUP	Counties Power Ltd	1%
TRUG	Manawa Energy Ltd	1%
WAIP	Waipa Networks Ltd	0.9%
PANP	Pan Pac Forest Product Ltd	0.8%
HORO	Electra Ltd	0.7%
EAST	Eastland Network Ltd	0.6%
NZST	New Zealand Steel Ltd	0.5%
WTOM	The Lines Company Ltd	0.5%
HRZE	Horizon Energy Distribution Ltd	0.4%
CHBP	Centralines Ltd	0.3%
KUPE	Beach Energy Resources NZ (Holdings) Ltd	0.2%
SCAN	Scanpower Ltd	0.2%
DUNE	Aurora Energy Ltd	0.2%
METH	Methanex New Zealand Ltd	0.1%
OMVP	OMV NZ Production Ltd	0.1%
WPOW	Westpower Ltd	0.1%
TRNZ	KiwiRail Holdings Ltd	0.1%
ALPE	Alpine Energy Ltd	< 0.05%
TASM	Network Tasman Ltd	< 0.05%
KIWI	Whareroa Cogeneration Ltd	< 0.05%
MELW	MEL (West Wind) Ltd	< 0.05%

Customer Code	Customer Name	Indicative starting allocation (%)
MSVP	Mercury SPV Ltd	< 0.05%
TARW	Tararua Wind Power	< 0.05%
WAV1	Waverly Wind Farm Ltd	< 0.05%
MRPL	Mercury NZ Ltd	< 0.005%
MELT	MEL (Te Apiti) Ltd	< 0.005%
SHPK	Southpark Utilities Ltd	< 0.005%
TBOP	Nova Energy Ltd	< 0.005%

4 Indicative increase in transmission charges

We have calculated the total indicative increase in transmission charges (specifically BBCs) for each affected GXP/GIP by multiplying the indicative covered cost of the HVDC Upgrade Stage 1 BBI by the indicative starting allocations from section 3.2.3 above.

Note that Tables 4 and 5 show the indicative increase in BBCs associated with the HVDC Link Upgrade Stage 1 BBI, but not the decrease in residual charges that will result from commissioning the BBI. This decrease will happen because the BBI's covered cost will include an attribution of some of Transpower's operating costs (in proportion to the BBI's depreciation), which will shift revenue from residual charges to the BBCs. The decrease in residual charges will be shared across all Transpower's load customers, not just those in the North Island.

Table 4: Indicative increases in transmission charges – demand groups

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied (c/kWh)
Centralines Ltd	WPW	NI	401.7	0.34
Counties Power Ltd	BOB	NI	1,544.2	0.34
Counties Power Ltd	GLN	NI	562.7	0.34
Contact Energy Ltd	WHI	NI	4.6	0.34
Contact Energy Ltd	WRK	NI	0.1	0.34
Eastland Network Ltd	TUI	NI	1,000.5	0.34

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied (c/kWh)
Electra Ltd	MHO	NI	161.2	0.19
Electra Ltd	PRM	NI	898.4	0.34
Horizon Energy Distribution Ltd	EDG	NI	367.8	0.34
Horizon Energy Distribution Ltd	KAW	NI	8.2	0.19
Horizon Energy Distribution Ltd	WAI	NI	206.8	0.34
Beach Energy Resources NZ (Holdings) Ltd	HWA	NI	352.8	0.45
Methanex New Zealand Ltd	MNI	NI	222.7	0.45
Mercury NZ Ltd	SWN	NI	7.3	0.34
Northpower Ltd	BRB	NI	771.6	0.34
Northpower Ltd	MPE	NI	1,994.7	0.34
Northpower Ltd	MTO	NI	366.4	0.34
New Zealand Steel Ltd	GLN	NI	856.4	0.19
OMV NZ Production Ltd	MNI	NI	173.3	0.45
Pan Pac Forest Product Ltd	WHI	NI	1,246.4	0.45
Powerco Ltd	ARI	NI	215.2	0.34
Powerco Ltd	BPE	NI	1,160.3	0.34
Powerco Ltd	BRK	NI	425.4	0.34
Powerco Ltd	CST	NI	952.9	0.34
Powerco Ltd	GYT	NI	213.2	0.34

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied (c/kWh)
Powerco Ltd	HIN	NI	610.3	0.34
Powerco Ltd	HUI	NI	457.1	0.34
Powerco Ltd	HWA	NI	525.1	0.34
Powerco Ltd	KIN	NI	1,282.8	0.34
Powerco Ltd	KMO	NI	381.6	0.34
Powerco Ltd	KPU	NI	757.4	0.34
Powerco Ltd	LTN	NI	604.5	0.34
Powerco Ltd	MGM	NI	271.4	0.34
Powerco Ltd	MST	NI	757.7	0.34
Powerco Ltd	MTM	NI	980.6	0.34
Powerco Ltd	MTN	NI	299.3	0.34
Powerco Ltd	MTR	NI	113.0	0.34
Powerco Ltd	OKN	NI	28.0	0.34
Powerco Ltd	OPK	NI	165.2	0.34
Powerco Ltd	PAO	NI	694.8	0.34
Powerco Ltd	SFD	NI	436.1	0.34
Powerco Ltd	TGA	NI	1,320.5	0.34
Powerco Ltd	TMI	NI	774.9	0.34
Powerco Ltd	WGN	NI	519.4	0.34
Powerco Ltd	WHU	NI	574.1	0.34

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied (c/kWh)
Powerco Ltd	WKO	NI	626.6	0.34
Powerco Ltd	WVY	NI	75.0	0.34
Scanpower Ltd	DVK	NI	233.9	0.34
Scanpower Ltd	WDV	NI	44.7	0.34
Southpark Utilities Ltd	PEN	NI	2.0	0.45
Nova Energy Ltd	KPA	NI	0.2	0.34
KiwiRail Holdings Ltd	BPE	NI	6.5	0.45
KiwiRail Holdings Ltd	HAM	NI	5.3	0.45
KiwiRail Holdings Ltd	PEN	NI	69.6	0.45
KiwiRail Holdings Ltd	SWN	NI	68.8	0.45
KiwiRail Holdings Ltd	TMN	NI	6.9	0.45
KiwiRail Holdings Ltd	TNG	NI	7.2	0.45
Wellington Electricity Lines Ltd	CPK	NI	2,482.7	0.34
Wellington Electricity Lines Ltd	GFD	NI	934.4	0.34
Wellington Electricity Lines Ltd	HAY	NI	476.8	0.34
Wellington Electricity Lines Ltd	KWA	NI	454.8	0.34
Wellington Electricity Lines Ltd	MLG	NI	835.8	0.34
Wellington Electricity Lines Ltd	PNI	NI	234.5	0.34

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied (c/kWh)
Wellington Electricity Lines Ltd	TKR	NI	1,412.9	0.34
Wellington Electricity Lines Ltd	UHT	NI	459.4	0.34
Wellington Electricity Lines Ltd	WIL	NI	247.9	0.34
Unison Networks Ltd	FHL	NI	985.2	0.34
Unison Networks Ltd	OWH	NI	191.6	0.34
Unison Networks Ltd	RDF	NI	980.4	0.34
Unison Networks Ltd	ROT	NI	1,141.0	0.34
Unison Networks Ltd	TRK	NI	124.7	0.34
Unison Networks Ltd	WTU	NI	1,456.0	0.34
Vector Ltd	ALB	NI	3,159.2	0.34
Vector Ltd	HEN	NI	1,760.4	0.34
Vector Ltd	HEP	NI	2,091.9	0.34
Vector Ltd	HOB	NI	919.7	0.34
Vector Ltd	LFD	NI	225.1	0.34
Vector Ltd	MNG	NI	2,188.9	0.34
Vector Ltd	OTA	NI	1,023.0	0.34
Vector Ltd	PAK	NI	2,172.4	0.34
Vector Ltd	PEN	NI	7,074.0	0.34
Vector Ltd	ROS	NI	2,308.2	0.34

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied (c/kWh)
Vector Ltd	SVL	NI	1,284.0	0.34
Vector Ltd	TAK	NI	1,796.8	0.34
Vector Ltd	WEL	NI	589.6	0.34
Vector Ltd	WIR	NI	1,606.9	0.34
Vector Ltd	WRD	NI	1,021.0	0.34
Waipa Networks Ltd	CBG	NI	803.9	0.34
Waipa Networks Ltd	TMU	NI	666.7	0.34
WEL Networks Ltd	HAM	NI	2,565.6	0.34
WEL Networks Ltd	HLY	NI	464.3	0.34
WEL Networks Ltd	TWH	NI	603.1	0.34
The Lines Company Ltd	HTI	NI	535.9	0.34
The Lines Company Ltd	NPK	NI	52.0	0.34
The Lines Company Ltd	OKN	NI	63.0	0.34
The Lines Company Ltd	ONG	NI	55.1	0.34
The Lines Company Ltd	TKU	NI	120.2	0.34

Table 5: Indicative increases in transmission charges (BBCs) – supply groups

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of generation (c/kWh)
Alpine Energy Ltd	ABY	SI	69.0	0.48
Contact Energy Ltd	CYD	SI	9,992.7	0.48
Contact Energy Ltd	ROX	SI	8,028.1	0.48
Aurora Energy Ltd	CYD	SI	234.3	0.48
Genesis Energy Ltd	HLY	NI	43.6	<0.005
Genesis Energy Ltd	TKA	SI	665.0	0.48
Genesis Energy Ltd	TKB	SI	4,337.5	0.48
Whareroa Cogeneration Ltd	HWA	NI	16.8	0.01
MEL (Te Apiti) Ltd	WDV	NI	6.7	<0.005
MEL (West Wind) Ltd	WWD	NI	12.5	<0.005
Meridian Energy Ltd	AVI	SI	4,954.9	0.48
Meridian Energy Ltd	BEN	SI	12,230.6	0.48
Meridian Energy Ltd	HRP	NI	13.3	<0.005
Meridian Energy Ltd	MAN	SI	22,706.5	0.48
Meridian Energy Ltd	OHA	SI	5,999.4	0.48
Meridian Energy Ltd	OHB	SI	5,056.5	0.48
Meridian Energy Ltd	OHC	SI	5,022.4	0.48

Customer	Location	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of generation (c/kWh)
Meridian Energy Ltd	WTK	SI	2,560.6	0.48
Mercury SPV Ltd	LTN	NI	10.9	<0.005
Tararua Wind Power	TWC	NI	10.4	<0.005
Network Tasman Ltd	MCH	SI	44.7	0.48
Manawa Energy Ltd	ARG	SI	198.3	0.48
Manawa Energy Ltd	BWK	SI	512.5	0.48
Manawa Energy Ltd	COL	SI	1,220.0	0.48
Waverly Wind Farm Ltd	WVY	NI	8.3	<0.005
Westpower Ltd	KUM	SI	172.2	0.48

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