TPM consultation – Indicative pricing workshop

2 November 2021

TRANSPOWER

Transpower staff are presenting to this Authority-led technical workshop as the developers of the indicative pricing and case studies that support the Authority's consultation. Authority staff will respond to any non-technical questions stakeholders may have.

Purpose of this slide deck

The purpose of this slide deck is to support a discussion on the technical aspects of indicative prices under the proposed new TPM.

The slide deck provides:

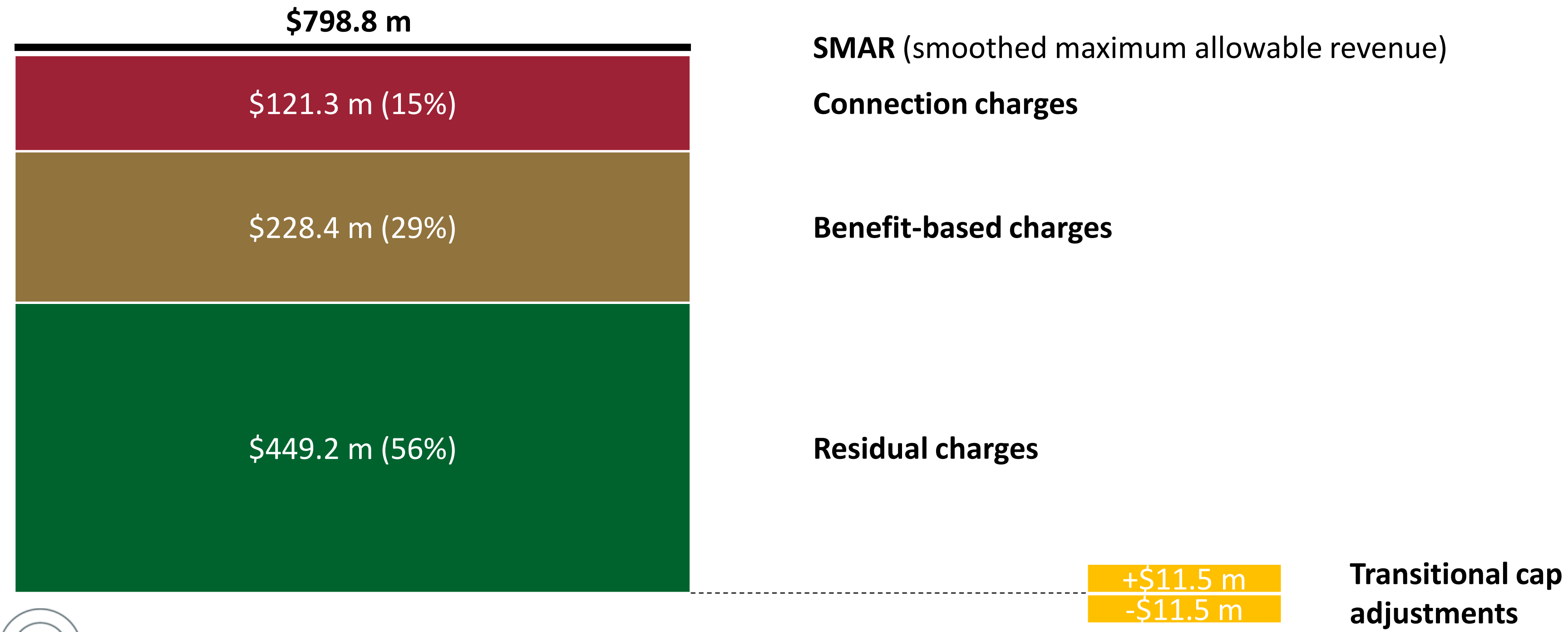
- a high-level overview of indicative prices for the 21/22 pricing year (as if the new TPM had applied for that pricing year) as included in Transpower's TPM proposal to the Electricity Authority from 30 June 2021 (including subsequent updates)
- introduces the various charges under the proposed new TPM; and
- projects the trajectory of charges into the future.

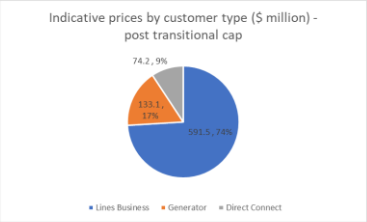
This slide pack is not a comprehensive summary of the mechanics underpinning Transpower's indicative prices for the 21/22 pricing year. More information is available here (see also last slide).

Stakeholders should not rely on the indicative prices for their price-setting or budgeting purposes. Transpower will notify actual transmission prices for the first and subsequent pricing years under the new TPM in the normal way.

Indicative prices for the 21/22 pricing year

Transpower recovery of its allowable revenue



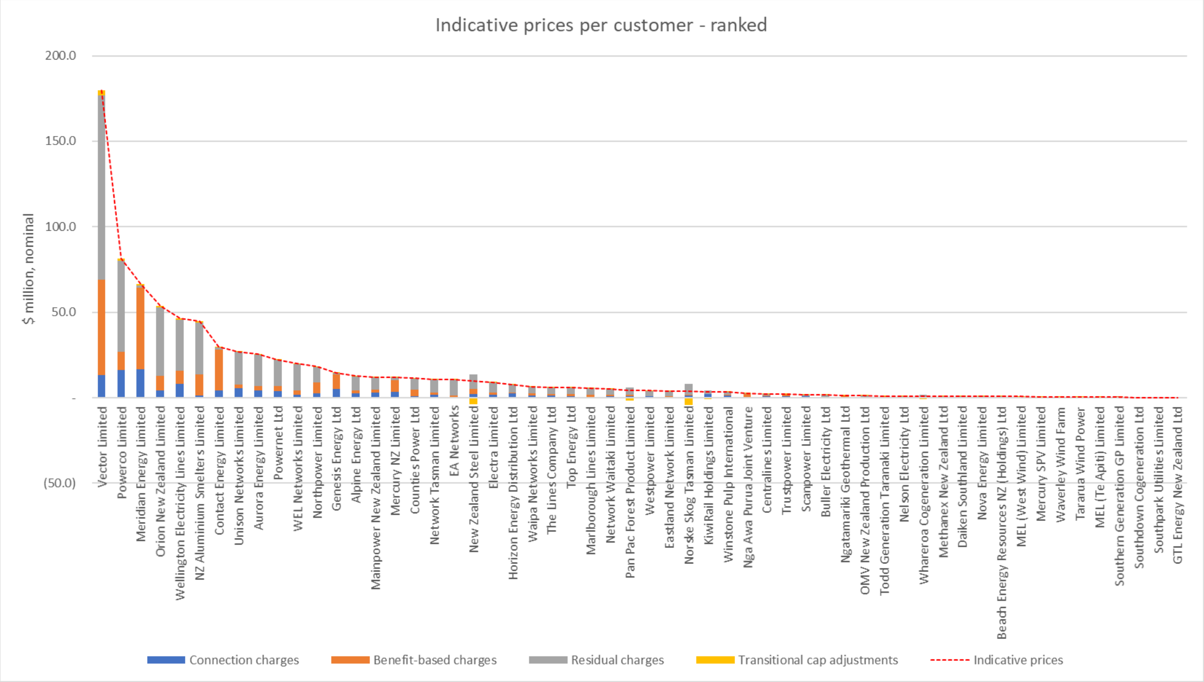


Indicative prices by customer (table)

Customer name	Ranking	Indicative prices	% of total charges	% of total charges (cum)	Connection charges	Benefit-based charges	Residual charges	Transitional cap adjustments
Vector Limited	1	179.9	22.5%	22.5%	13.2	55.7	108.2	2.9
Powerco Limited	2	81.3	10.2%	32.7%	16.0	10.9	53.2	1.1
Meridian Energy Limited	3	66.6	8.3%	41.0%	16.6	47.8	1.4	0.9
Orion New Zealand Limited	4	53.5	6.7%	47.7%	4.1	8.9	39.7	0.9
Wellington Electricity Lines Limited	5	46.3	5.8%	53.5%	8.2	7.6	29.8	0.7
NZ Aluminium Smelters Limited	6	44.7	5.6%	59.1%	1.3	12.4	30.3	0.8
Contact Energy Limited	7	29.8	3.7%	62.9%	4.2	23.8	1.4	0.4
Unison Networks Limited	8	27.0	3.4%	66.2%	5.6	2.2	18.8	0.4
Aurora Energy Limited	9	25.4	3.2%	69.4%	4.3	2.7	18.1	0.4
Powernet Ltd	10	22.3	2.8%	72.2%	3.8	2.9	15.3	0.3
WEL Networks Limited	11	20.0	2.5%	74.7%	1.7	2.7	15.3	0.3
Northpower Limited	12	18.3	2.3%	77.0%	2.5	6.5	9.0	0.3
Genesis Energy Ltd	13	14.5	1.8%	78.8%	5.0	8.7	0.7	0.1
Alpine Energy Ltd	14	12.6	1.6%	80.4%	2.6	1.6	8.2	0.2
Mainpower New Zealand Limited	15	12.1	1.5%	81.9%	2.9	1.6	7.5	0.2
Mercury NZ Limited	16	12.1	1.5%	83.4%	3.5	6.7	1.8	0.1
Counties Power Ltd	17	11.3	1.4%	84.8%	1.0	3.5	6.7	0.2
Network Tasman Limited	18	10.7	1.3%	86.2%	1.5	1.4	7.7	0.2
EA Networks	19	10.7	1.3%	87.5%	0.3	1.0	9.2	0.2
New Zealand Steel Limited	20	10.0	1.2%	88.8%	2.3	2.7	8.8	(3.8)
Electra Limited	21	9.0	1.1%	89.9%	1.6	1.5	5.8	0.1
Horizon Energy Distribution Ltd	22	7.7	1.0%	90.8%	2.4	0.4	4.8	0.1
Waipa Networks Limited	23	6.3	0.8%	91.6%	1.2	1.2	3.9	0.1
The Lines Company Ltd	24	6.1	0.8%	92.4%	1.4	0.7	3.9	0.1
Top Energy Ltd	25	5.9	0.7%	93.1%	1.0	1.2	3.6	0.1
Marlborough Lines Limited	26	5.4	0.7%	93.8%	0.6	1.0	3.8	0.1
Network Waitaki Limited	27	5.3	0.7%	94.5%	0.9	0.7	3.6	0.1
Pan Pac Forest Product Limited	28	4.2	0.5%	95.0%	1.0	0.8	4.1	(1.7)
Westpower Limited	29	4.1	0.5%	95.5%	0.7	0.2	3.1	0.1
Eastland Network Limited	30	4.0	0.5%	96.0%	0.3	0.6	3.1	0.1

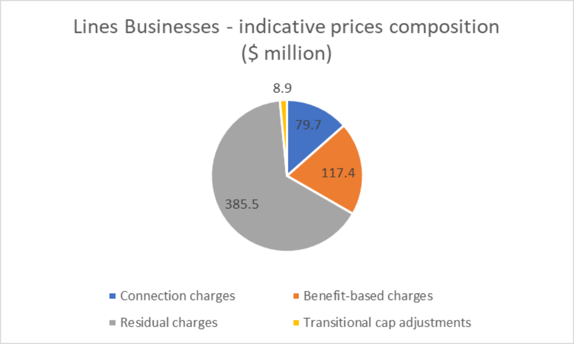
Customer name	Ranking	Indicative prices	% of total charges	% of total charges (cum)	Connection charges	Benefit-based charges	Residual charges	Transitional cap adjustments
Norske Skog Tasman Limited	31	3.8	0.5%	96.5%	1.2	0.5	6.4	(4.2)
KiwiRail Holdings Limited	32	3.5	0.4%	96.9%	2.0	0.3	2.2	(0.9)
Winstone Pulp International	33	3.5	0.4%	97.4%	1.1	0.5	1.9	0.0
Nga Awa Purua Joint Venture	34	2.5	0.3%	97.7%	0.4	1.7	0.3	0.0
Centralines Limited	35	2.2	0.3%	98.0%	0.8	0.4	1.1	0.0
Trustpower Limited	36	2.0	0.2%	98.2%	0.8	1.1	0.0	0.0
Scanpower Limited	37	1.7	0.2%	98.4%	0.6	0.3	0.8	0.0
Buller Electricity Ltd	38	1.6	0.2%	98.6%	0.5	0.1	1.0	0.0
Ngatamariki Geothermal Ltd	39	1.4	0.2%	98.8%	0.3	1.0	0.0	0.0
OMV New Zealand Production Ltd	40	1.1	0.1%	98.9%	0.3	0.2	0.6	0.0
Todd Generation Taranaki Limited	41	1.0	0.1%	99.1%	0.1	0.8	0.1	0.0
Nelson Electricity Ltd	42	0.9	0.1%	99.2%	0.1	0.1	0.7	0.0
Whareroa Cogeneration Limited	43	0.9	0.1%	99.3%	0.2	0.1	1.6	(0.9)
Methanex New Zealand Ltd	44	0.9	0.1%	99.4%	0.2	0.1	0.5	0.0
Daiken Southland Limited	45	0.8	0.1%	99.5%	0.2	0.2	0.5	0.0
Nova Energy Limited	46	0.7	0.1%	99.6%	0.3	0.1	0.4	0.0
Beach Energy Resources NZ (Holdings) Ltd	47	0.7	0.1%	99.7%	0.1	0.2	0.5	0.0
MEL (West Wind) Limited	48	0.6	0.1%	99.8%	0.1	0.4	0.1	0.0
Mercury SPV Limited	49	0.6	0.1%	99.8%	0.1	0.4	0.1	0.0
Waverley Wind Farm	50	0.4	0.0%	99.9%	0.1	0.2	0.1	0.0
Tararua Wind Power	51	0.3	0.0%	99.9%	0.1	0.2	0.1	0.0
MEL (Te Apiti) Limited	52	0.3	0.0%	99.9%	0.1	0.2	0.0	0.0
Southern Generation GP Limited	53	0.2	0.0%	100.0%	0.2	0.0	-	-
Southdown Cogeneration Ltd	54	0.2	0.0%	100.0%	0.0	0.0	0.1	0.0
Southpark Utilities Limited	55	0.0	0.0%	100.0%	0.0	0.0	0.0	0.0
GTL Energy New Zealand Ltd	56	0.0	0.0%	100.0%	0.0	0.0	0.0	(0.0)
Total		**798.9**			**121.3**	**228.4**	**449.2**	**0.0**
Lines Business	1	591.5	74.0%	74.0%	79.7	117.4	385.5	8.9
Generator	2	133.1	16.7%	90.7%	31.8	93.2	6.5	1.7
Direct Connect	3	74.2	9.3%	100.0%	9.8	17.8	57.2	-10.6
Total		**798.9**			**121.3**	**228.4**	**449.2**	**-**

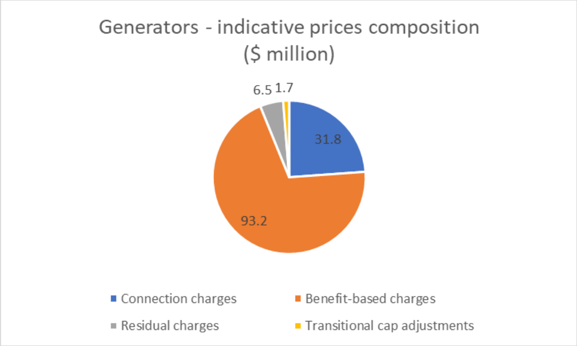
Indicative prices by customer (graph)

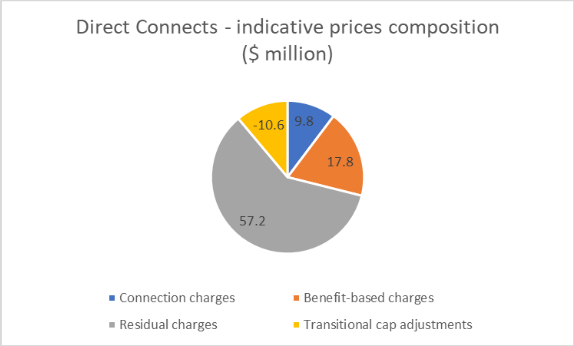


- Indicative prices can vary greatly – by customer and by charge

Indicative prices breakdown by customer type



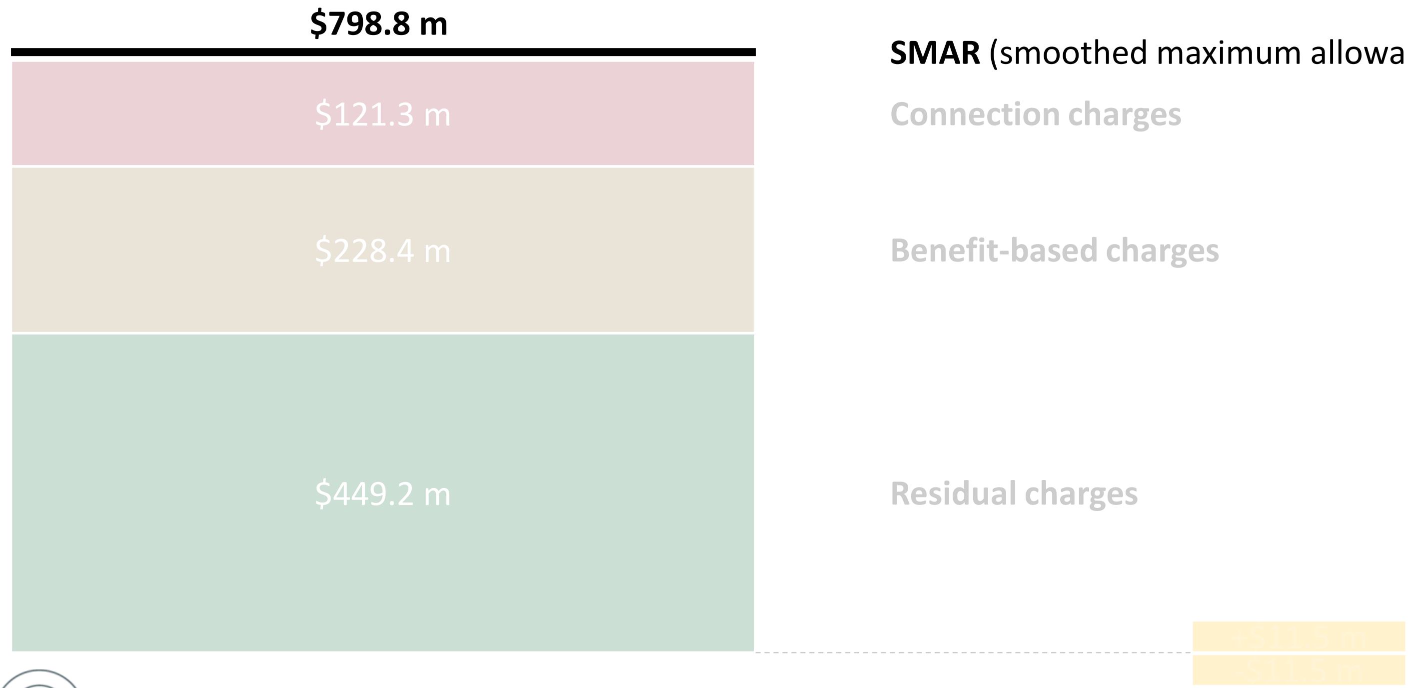




- The dominant charge for lines businesses and direct connects is (and will remain for some time) the residual charge, paying for Transpower's interconnection assets as at June 2019 (with some exceptions) and its non-grid assets
- Generators will pay residual charges only to the extent they have offtake from the grid, which is a very small amount. Their prices for the interconnected grid are almost entirely benefit-based charges
- Note: Connection charges remain largely unchanged

Indicative prices by charge component

SMAR



SMAR (smoothed maximum allowable revenue)

Connection charges

Benefit-based charges

Residual charges

Transitional cap adjustments

SMAR sets the ceiling

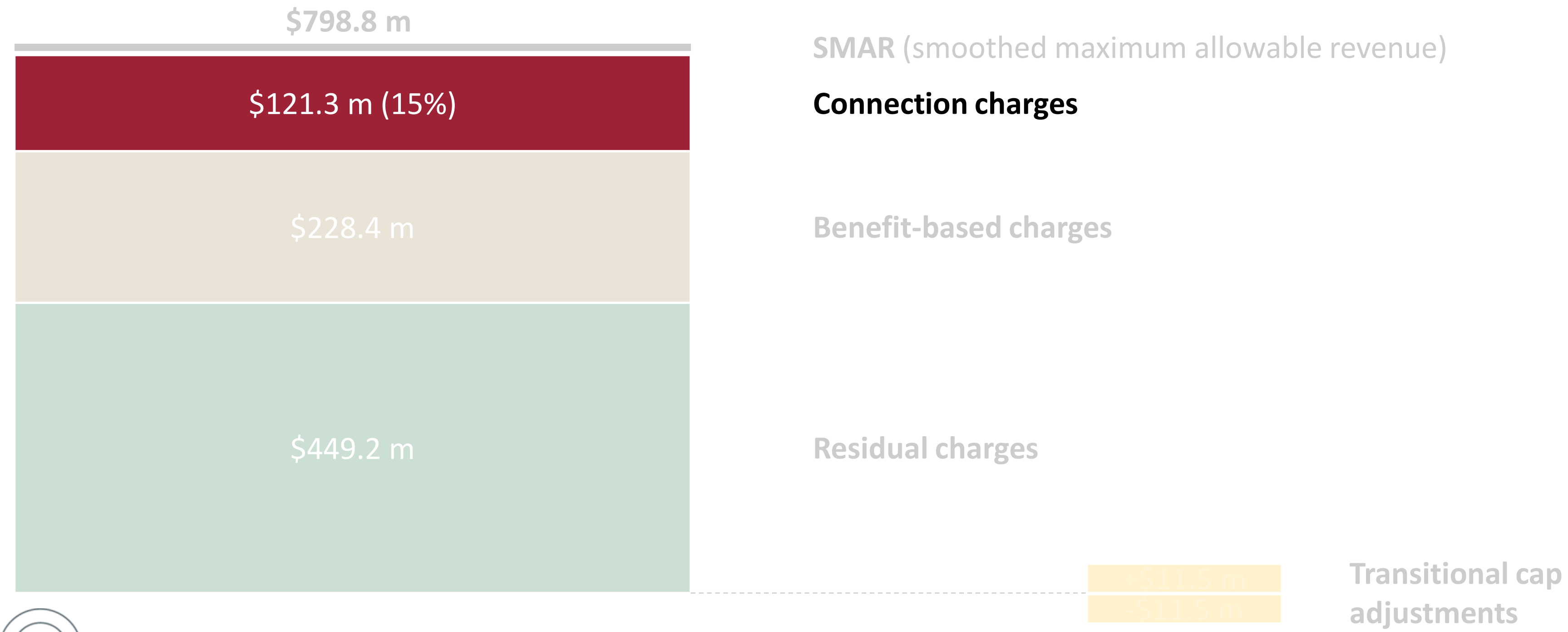
- The Commerce Commission determines Transpower's annual MAR for a five-year RCP
- Transpower's MAR is equivalent to an EDB's BBAR (Building Blocks Allowable Revenue)
- MAR is then smoothed (following a constant growth rate) to remove volatility from transmission revenue
- The resulting SMAR (smoothed MAR) is applied to the TPM (i.e. sets the ceiling)

Schedule A: Summary of forecast MAR and forecast SMAR

Forecast MAR applied to pricing years in RCP3 ending	Forecast MAR is calculated based on building block values for the disclosure year ending	Initial determined value of forecast MAR for pricing year	Incremental update to forecast MAR determined in 2020	Incremental update to forecast MAR determined in 2021	Incremental update to forecast MAR determined in 2022	Incremental update to forecast MAR determined in 2023	Total forecast MAR applicable to the pricing year (sum of amounts in columns 3 to 7)	Forecast SMAR applicable to the pricing years in RCP3
[Column 1]	[Column 2]	[Column 3]	[Column 4]	[Column 5]	[Column 6]	[Column 7]	[Column 8]	[Column 9]
31 March 2021 (Year 1)	30 June 2021	$810.6 million	N/A	N/A	N/A	N/A	$810.6 million	$788.7 million
31 March 2022 (Year 2)	30 June 2022	$795.6 million	$X.X million	N/A	N/A	N/A	$795.6 million	$798.8 million
31 March 2023 (Year 3)	30 June 2023	$790.9 million	$XX million	$X.X million	N/A	N/A	$790.9 million	$809.0 million
31 March 2024 (Year 4)	30 June 2024	$821.3 million	$X.X million	$X.X million	$X.X million	N/A	$821.3 million	$819.0 million
31 March 2025 (Year 5)	30 June 2025	$824.4 million	$X.X million	$X.X million	$X.X million	$X.X million	$824.4 million	$829.3 million

This is Transpower's SMAR as defined in the IPP for RCP3

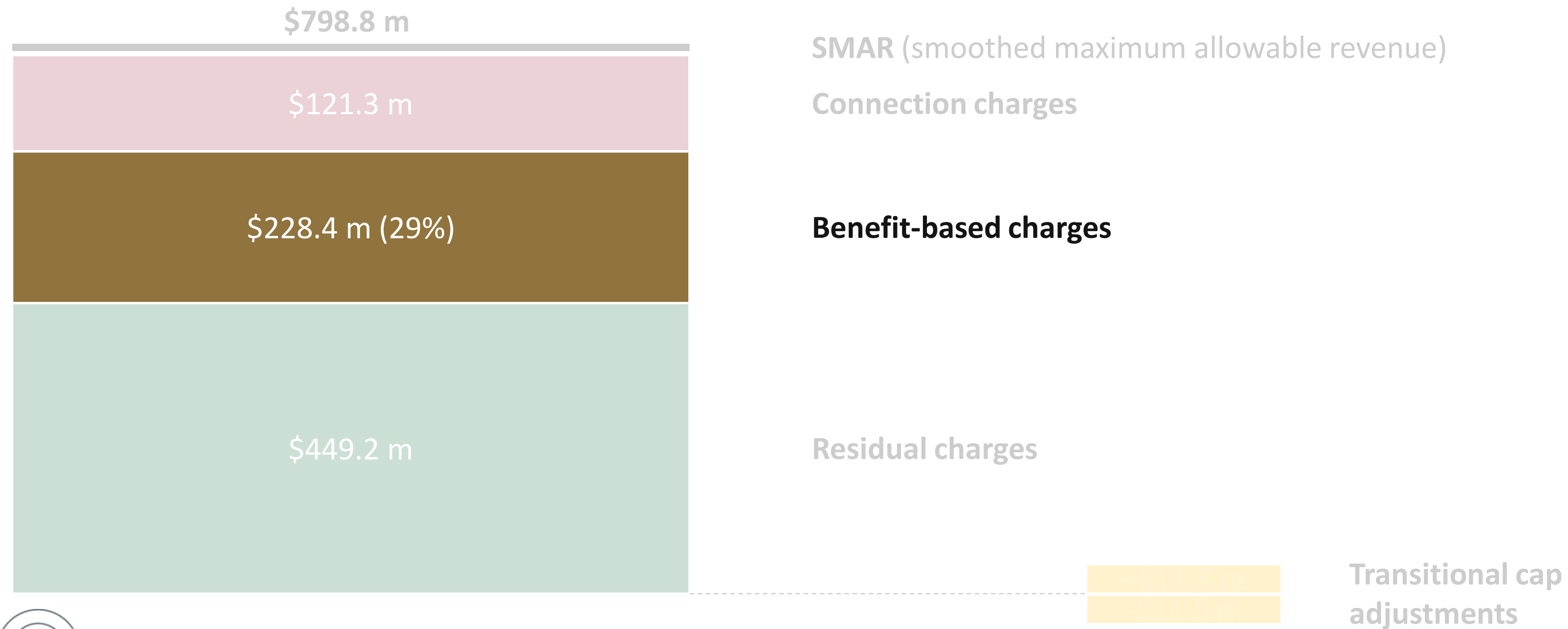
Connection charges



Connection charges largely unchanged

- The fundamental approach to calculating connection charges in the proposed new TPM is unchanged (there are some new proposals to address first mover disadvantage, which do not affect indicative prices)
- The connection charges used for indicative prices are sourced from Transpower's ID disclosures, where prices under the TPM for the 21/22 pricing year have already been disclosed
- Connection charges at certain locations have been adjusted for some customers to show the impact of proposed Code changes:
  - ➢ Aurora and Powernet at Halfway Bush (removal of PDA)
  - ➢ Trustpower at Berwick (removal of PDA)
  - ➢ Southern Generation and Trustpower at Matahina (removal of PDA)
  - ➢ Network Waitaki at Blackpoint (removal of NEA)
  - ➢ Buller at Orowaiti Tee (lines into substation reclassified as connection assets)

Benefit-based charges



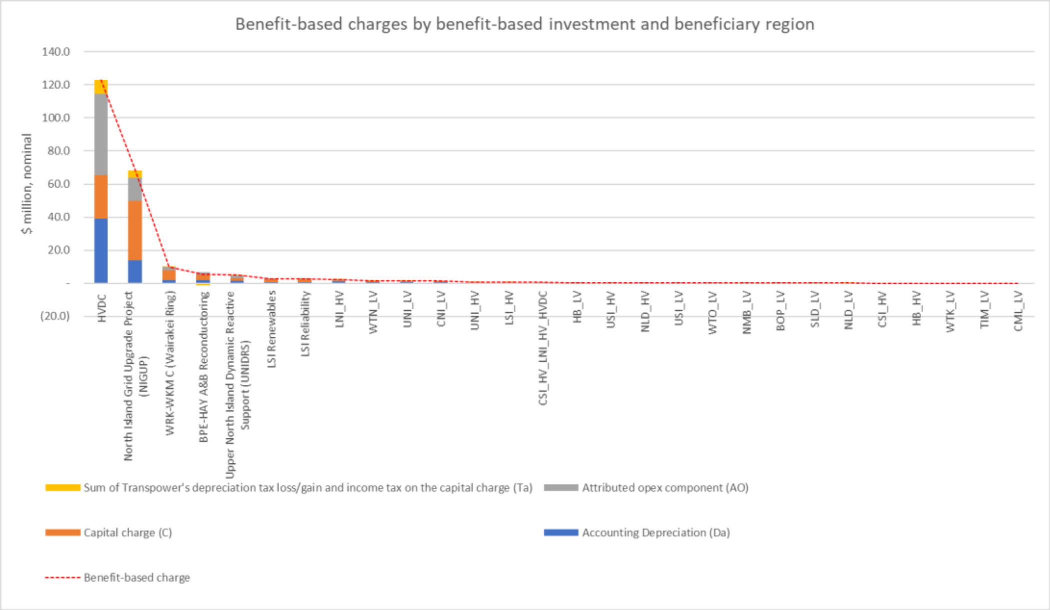
Purpose and calculation of benefit-based charges

- Benefit-based charges recover the costs of seven large historical, and post July 2019 interconnection investments from parties who are expected to benefit from them
- Calculating benefit-based charges requires two inputs: Covered Cost and Beneficiary Allocations, the latter calculated on a per investment basis (>$20m) or a simplified regional basis (<$20m)

Benefit-based Charge = Covered Cost (by investment) x Beneficiary Allocation (by customer)

- Benefit-based charges will change over time
- Whilst the covered cost will move up or down as the comprising assets depreciate (and are replaced), the allocations remain fixed (unless re-opened in limited, specified circumstances)

Benefit-based charges by investment and region

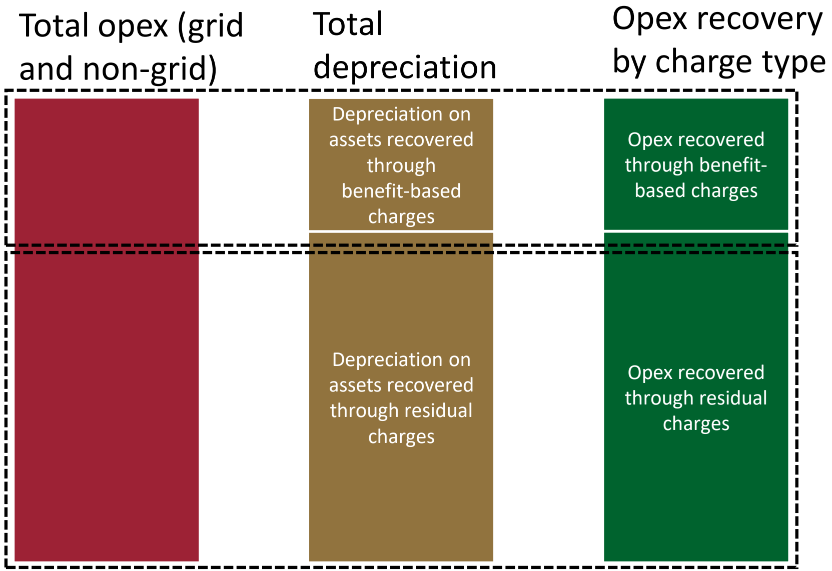


- The aggregated benefit-based charges are equal to the covered cost by investment or region
- For 21/22 indicative prices, the contribution from post July 2019 commissioning to total benefit-based charges is very small (5%)
- 95% of benefit-based charges are in relation to the seven historical investments
- In 21/22, all post July 2019 commissioning is allocated to beneficiary regions

Covered cost building blocks

- The costs recovered through benefit-based charges (covered cost) comprise building blocks for:
  - Depreciation
  - Finance cost (the capital charge)
  - Attributed opex
  - Tax
- This is consistent with how Transpower's MAR is determined by the Commerce Commission

Attributed opex



This approach ensures that all interconnection investments (and non-grid assets) will be assigned a proportion of Transpower's total opex, regardless of whether recovery is through a benefit-based charge or a residual charge.

- Building blocks for depreciation and finance cost are driven by Transpower's actual (and audited) commissioning from the preceding financial year
- The tax calculation follows the tax rules
- Attributed opex is calculated using an opex/depreciation ratio:

$$\text{Attributed opex ratio (AOR)} = \frac{\text{Total Opex}}{\text{Total Depreciation}}$$

Example

Attributed opex (Investment A)

= AOR x Depreciation Investment A

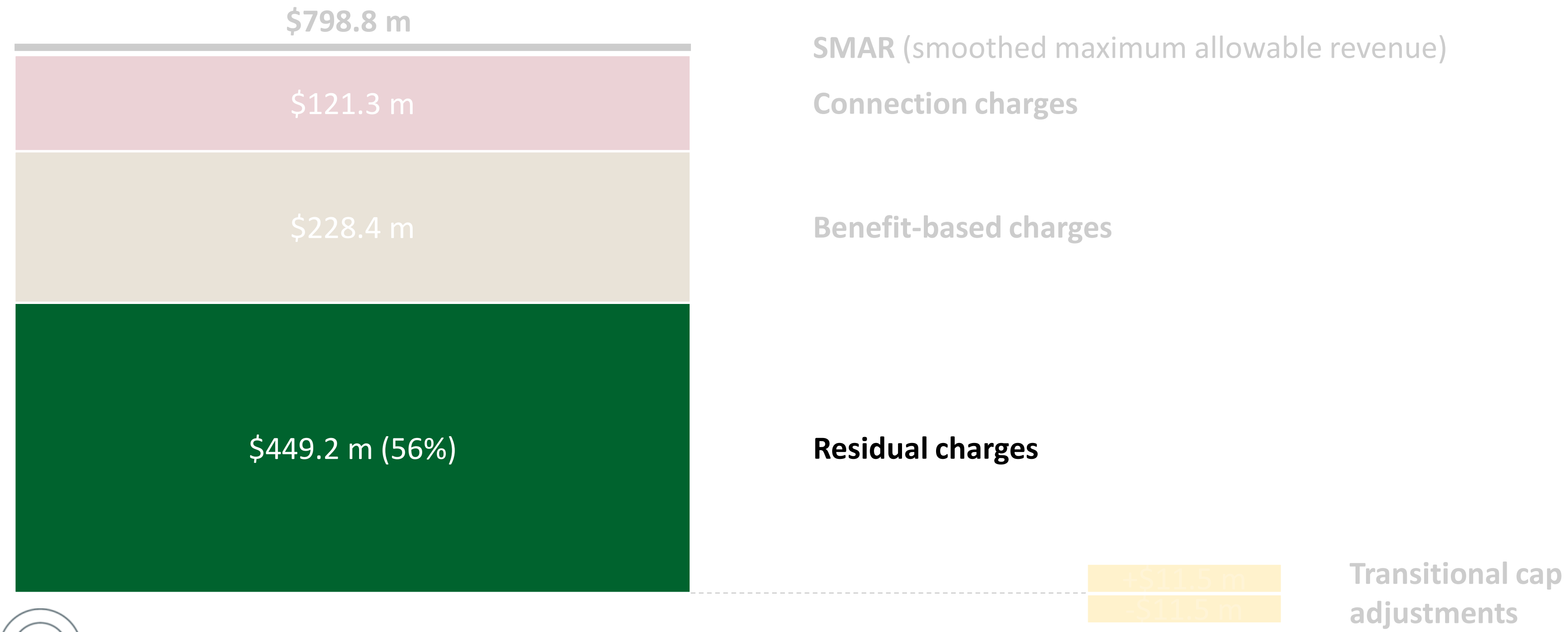
For 21/22 indicative prices, the AOR is 1.01. This means that for $1 of depreciation cost included in covered cost, another ~$1 of opex is added.

Covered cost by building block

Ranking	Benefit-based investments	Accounting Depreciation (Da)	Capital charge (C)	Attributed opex component (AO)	Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	Covered Cost (CC)
1	HVDC	39.2	26.2	49.3	8.2	**122.9**
2	North Island Grid Upgrade Project (NIGUP)	13.9	35.7	14.0	4.4	**68.1**
3	WRK-WKM C (Wairakei Ring)	2.0	5.8	2.1	0.1	**10.0**
4	BPE-HAY A&B Reconductoring	1.7	3.3	1.8	(1.2)	**5.6**
5	Upper North Island Dynamic Reactive Support (UNIDRS)	1.4	1.7	1.5	0.2	**4.9**
6	LSI Renewables	0.6	1.8	0.6	(0.2)	**2.9**
7	LSI Reliability	0.7	1.5	0.7	(0.1)	**2.9**
8	LNI_HV	0.9	0.4	1.0	0.1	**2.4**
9	WTN_LV	0.6	0.3	0.6	0.1	**1.6**
10	UNI_LV	0.5	0.3	0.5	0.1	**1.4**
11	CNI_LV	0.5	0.5	0.5	(0.2)	**1.4**
12	UNI_HV	0.3	0.1	0.3	0.0	**0.7**
13	LSI_HV	0.2	0.1	0.2	0.0	**0.6**
14	CSI_HV_LNI_HV_HVDC	0.3	0.1	0.3	(0.1)	**0.6**
15	HB_LV	0.2	0.1	0.2	(0.0)	**0.4**
16	USI_HV	0.1	0.1	0.1	(0.0)	**0.4**
17	NLD_HV	0.2	0.1	0.2	(0.0)	**0.4**
18	USI_LV	0.2	0.1	0.2	(0.1)	**0.3**
19	WTO_LV	0.1	0.1	0.1	(0.1)	**0.3**
20	NMB_LV	0.1	0.1	0.1	(0.1)	**0.3**
21	BOP_LV	0.1	0.1	0.1	(0.1)	**0.2**
22	SLD_LV	0.1	0.1	0.1	(0.1)	**0.2**
23	NLD_LV	0.0	0.0	0.0	0.0	**0.1**
24	CSI_HV	0.0	0.0	0.0	(0.0)	**0.1**
25	HB_HV	0.0	0.0	0.0	(0.0)	**0.1**
26	WTK_LV	0.0	0.0	0.0	(0.0)	**0.0**
27	TIM_LV	0.0	0.0	0.0	(0.0)	**0.0**
28	CML_LV	-	-	-	-	**-**
	Total	**64.1**	**78.5**	**74.5**	**11.2**	**228.4**

- Across all investments and regions, the capital charge is the largest building block (but WACC dependent)
- Opex is closely tracking depreciation
- The $10m difference (depreciation vs opex) is due to the HVDC cable insurance and reserve cost which are directly allocated to the HVDC benefit-based investment
- The negative tax for some investments/regions is because of high initial tax depreciation rates (but this effect is neutral across the life of an asset)

Residual charges



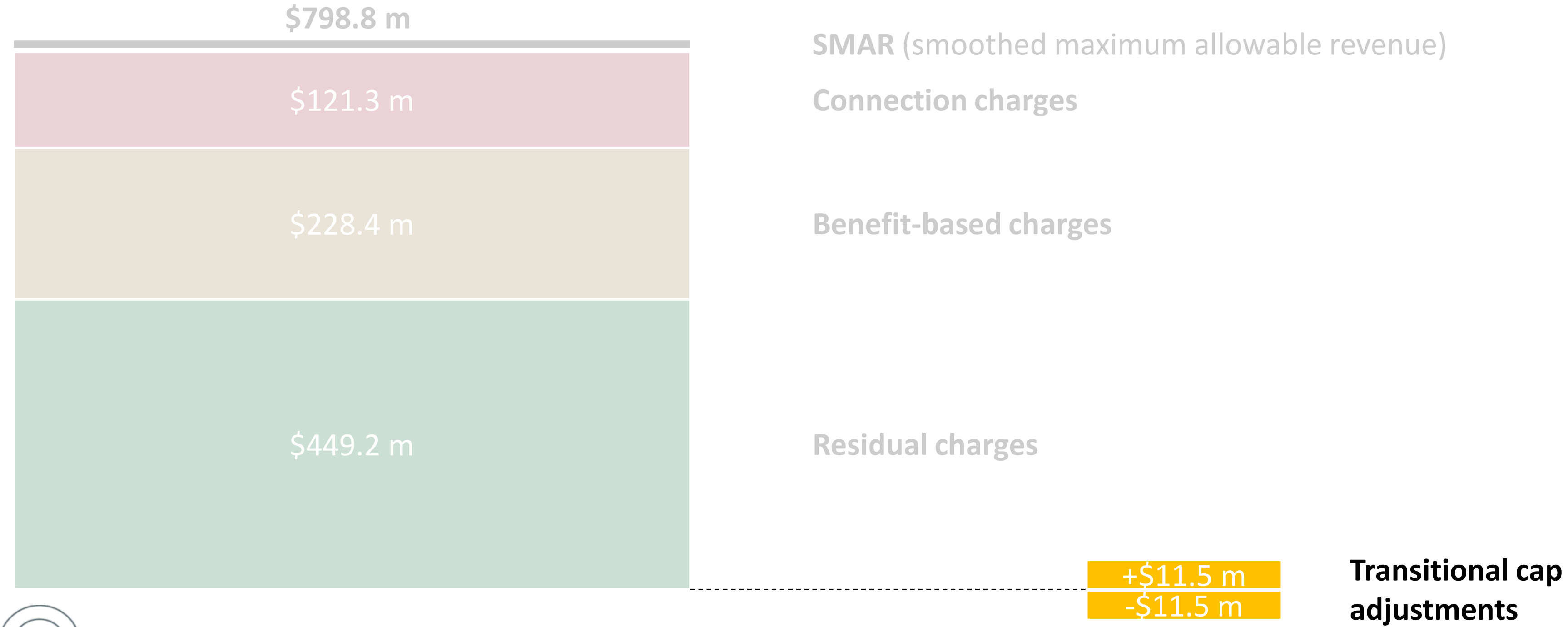
Purpose and calculation of residual charges

- Having deducted connection and benefit-based charges from the SMAR, residual charges recover Transpower's remaining revenue entitlement (residual revenue) from load customers
- Residual charges are allocated to load customers in accordance with their share of historic anytime maximum demand

Residual Charge = Residual Revenue / Total Anytime Maximum Demand x Anytime Maximum Demand (by customer)

- Generators get allocated residual charges too (in their role as load customers) – 1.4% of total residual charges

Transitional cap adjustments

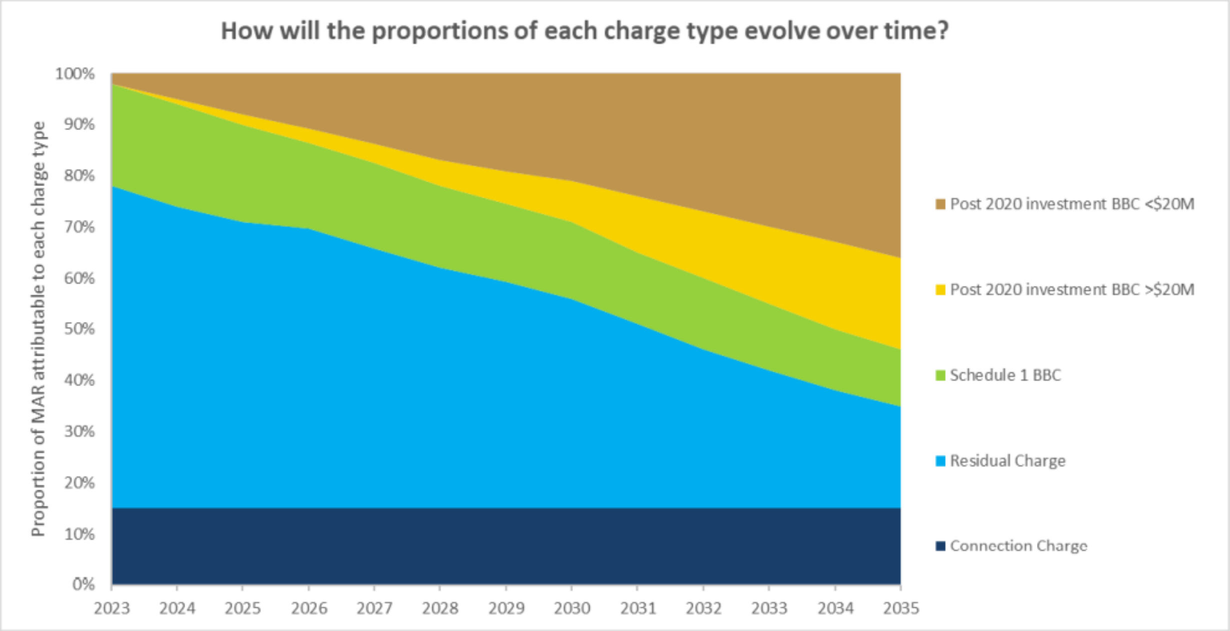


Purpose and effect of the transitional cap

- The transitional cap limits load customers’ potential transmission charge increase resulting from the impact of the seven historical investments on prices and residual charges under the proposed TPM relative to the interconnection charge under the current TPM (for the pricing year ending March 2020)
- Under that mechanism, some lines businesses and direct connects might be eligible to a reduction of their total transmission bill, which all other customers would have to pick up
- Overall, the impact from the transitional cap mechanism on Transpower’s recovery of its allowable revenue is nil
- Any surcharges or reductions under this mechanism can only be calculated at a customer level, i.e. it is not applicable at a location level

Projecting charges into the future

Projection of charges into the future



This projected trajectory of charges into the future is highly-uncertain and only demonstrates the directional shift in how Transpower's recoverable revenue is likely to be allocated between charge types over time.

- Over time, pre-2019 commissioned assets will depreciate and drop out of Transpower's asset base
- The residual charge will reduce, as well as the benefit-based charge for the seven historical investments (Schedule 1)
- Overall, the benefit-based charge will become the dominant charge as Transpower's RAB will predominantly comprise post-2019 investments in interconnection assets

More information

More information is available online

- This slide pack is not a comprehensive summary of the mechanics underpinning Transpower's indicative prices for the 21/22 pricing year. More information is available here
- The calculation of covered cost for the 21/22 pricing year is in this workbook
- The calculation of indicative prices for the 21/22 pricing year is in this workbook
- Additional pricing information for the 21/22 pricing year can be accessed here
- A comprehensive write-up of the reasons for Transpower's TPM proposal to the EA can be accessed here

Benefit-based charge – standard method case studies

Purpose of this slide deck

The purpose of this slide deck is to explain the results of the two high-value (>$20m) benefit-based case studies that accompanied in our TPM proposal:

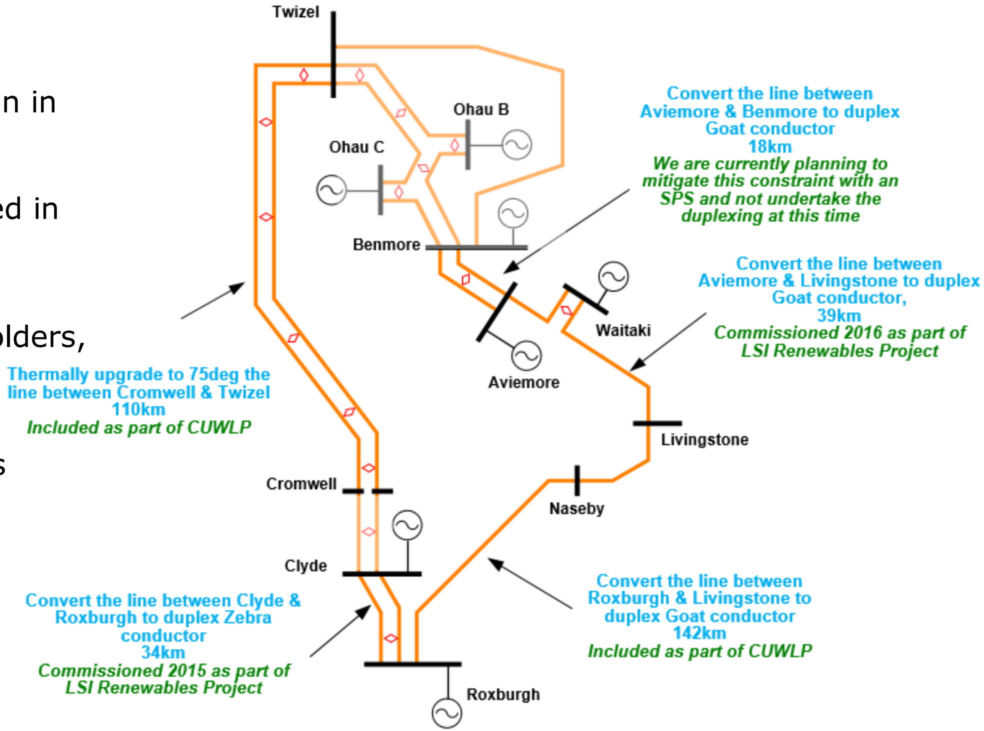
- The Clutha and Upper Waitaki Lines project (CUWLP)
- The first component of the Waikato and Upper North Island Voltage Management project (WUNIVM)

The results of these case studies do not necessarily represent the allocations that would result if the proposed TPM comes into effect, as the proposed TPM requires consultation with stakeholders prior to a final determination. However, they do illustrate the proposed methodology and framework for high-value benefit-based investments (BBIs).

Clutha and Upper Waitaki Lines project

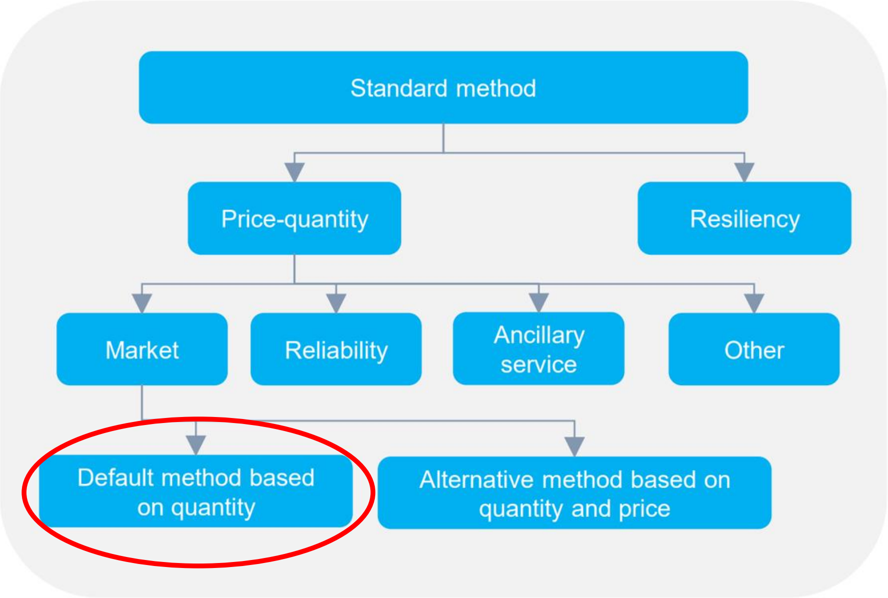
Background

- Originally approved by the Electricity Commission in April 2010 as part of the wider LSI Renewables project. The first components were commissioned in 2015-16.
- In May 2020 Transpower consulted with stakeholders, and committed to the project in June 2020.
- Project is expected to be fully commissioned this financial year, with a capital cost of $100m.



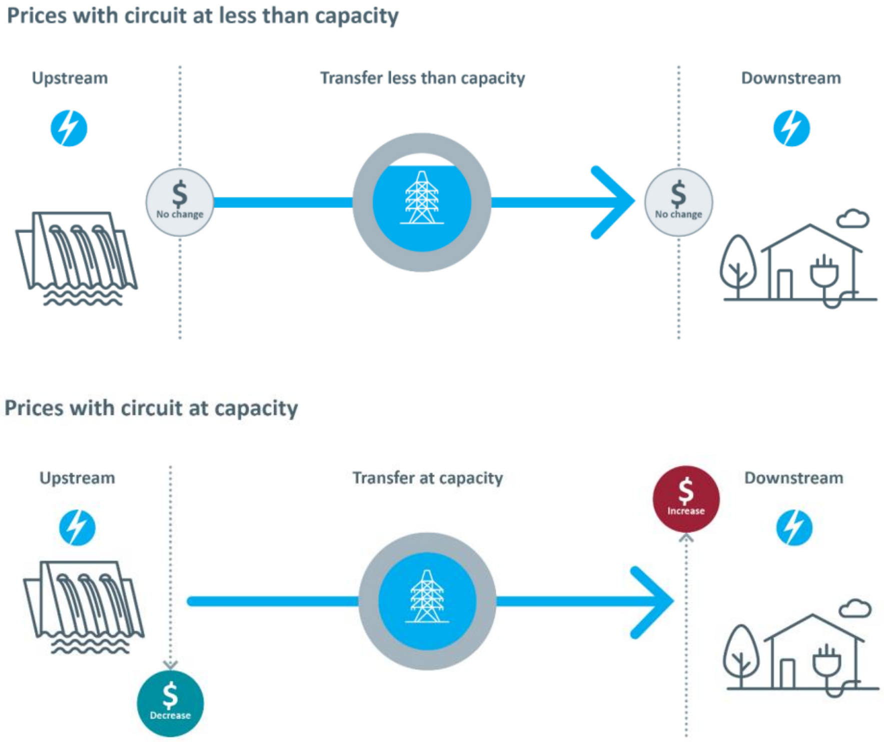
CUWLP primarily has market benefits

- CUWLP is a high-value BBI (>$20m) so uses the standard method.
- Not expected to have material reliability, ancillary service, or 'other' benefits.
- Benefits primarily relate to changes in the price and quantity of bids/offers in the wholesale market (market benefits).
- The default method for assessing market benefits is used, because we consider it to result in allocations that are broadly proportional to expected positive net-private benefits.



Market benefits are due to price and quantity changes

- Without transmission investment an upstream surplus in generation results in prices rising downstream and falling upstream when transmission reaches capacity.
- By increasing the capacity of the grid, generators upstream and loads downstream benefit from the investment. Generators downstream and loads upstream disbenefit.
- Generators and loads can also benefit if they produce/consume more as a result of the transmission investment.



Analytical process to produce allocations

- Benefits are assessed using the default method for assessing market benefits (clause 52 of the proposed TPM). This method models the market over 20 years with and without the investment, and identifies regions of benefit based on modelled changes to price and/or quantity, and calculates benefits as the quantity of load/generation exposed to the constraint plus any additional quantities resulting from the transmission investment.
- Clause 52 method gives even weight to the generators and loads benefitting either side of a constraint, and even weight to different benefitting regions (except where the HVDC is binding during periods of benefit).
- Positive benefits are netted against negative benefits to give a <u>net</u> private benefit.
- Regions may have sub-groups if we expect a group within that region to have materially different benefits (e.g. different generation technologies, or industrial vs. distribution load customers).
- Regional allocations are disaggregated to produce customer allocations using historical average or peak (depending on the nature of benefits) injection/offtake in the five capacity years (Sep – Aug) immediately preceding the decision to commit to the investment.

Regions and sub-groups identified based on model outputs

↓

Regional benefits calculated for each scenario

↓

Benefits combined across scenarios

↓

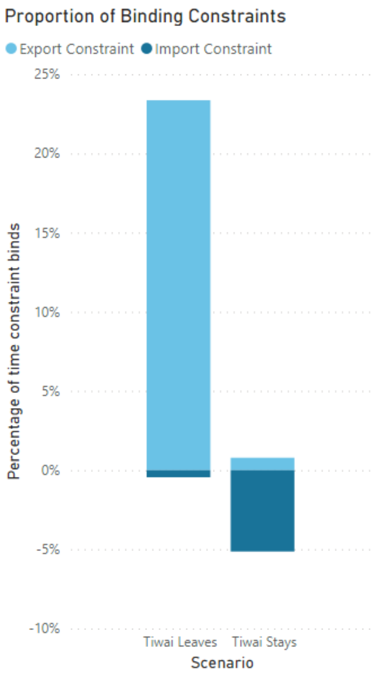
Positive and negative benefits netted

↓

Individual allocations calculated

Net-private benefits are assessed in two scenarios

- Benefits are assessed using two scenarios – one with Tiwai staying, and one with Tiwai leaving.
- Benefits accrue due to relieving import and export constraints. During periods of high inflows in the lower South Island (LSI), CUWLP allows more electricity to be exported to the rest of the grid from the LSI – benefitting LSI generators and loads in the upper South Island and the North Island. During periods of low inflows, CUWLP allows more electricity to be imported into the LSI, which reduces the risk of being unable to supply the load – benefitting loads in the LSI and generators in the USI and North Island.
- In the Tiwai leaves scenario, the export constraint binds much more frequently than the import constraint because there is a large surplus of generation in the region without Tiwai. The converse is true in the Tiwai stays scenario.
- Average offtake instead of peak injection/offtake is used as the intra-regional allocator because the times of benefit relate to inflows rather than peak periods.



CUWLP – indicative results

- North Island and Upper South Island distribution customers receive the largest allocation, in large part due to the large volume of load benefitting from the constraint being relieved. North Island direct connect customers receive a slightly smaller allocation than distribution customers (~80%) on a volume-weighted basis because – unlike distribution customers – their load is not expected to grow over time.

- LSI generators receive the second largest allocation commensurate with their large private benefit from the Tiwai leaves scenario.

- NZAS receive an allocation because it benefits in the Tiwai stays scenario, and this is the only scenario in which its benefits are assessed because it does not exist in the Tiwai leaves scenario.

- Very small allocation to North Island peakers because they benefit during the Tiwai stays scenario and do not disbenefit from the Tiwai leaves scenario (unlike other NI generation).

- Since our original case study (Transpower's 30 June TPM proposal reasons paper), we identified an enhancement to our clause 52 methodology which better accounts for the impact of the downstream HVDC constraints on allocations. This change incorporated in an addendum (28 September, published on the Authority's website) results in the rest of country region being split in two (North Island and upper South Island), with the charge to North Island beneficiaries falling by ~4%, and all other groups increasing by ~6%.

Region	Sub-group	Allocation
Lower South Island	Direct connect gen	21.73%
	Tiwai load	5.37%
Rest of country	Direct connect peakers	0.08%
	Direct connect industrial	3.38%
	All other offtake	69.44%

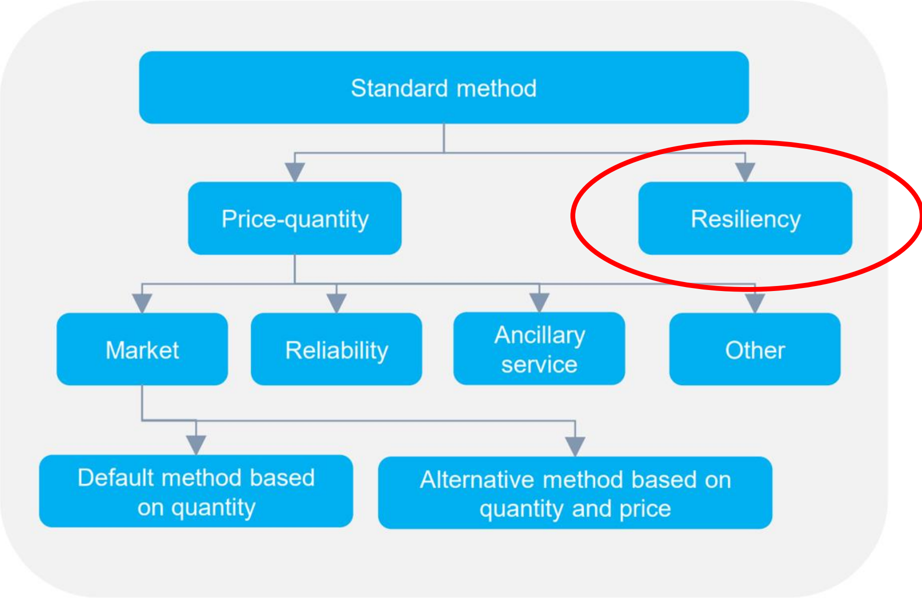
Waikato and Upper North Island Voltage Management project

Background

- As part of the regulated major capex project approval process, we consulted on the project in 2016 and 2019. In 2019, we proposed several components to the ComCom with a total capital cost of ~$140m.
- In Sep 2020, the ComCom approved the project and in Nov 2020 we committed to the first component – the dynamic reactive device (DRD) in Waikato, with a capital cost of ~$60m.
- The purpose of the project is to maintain voltage stability as load grows in the WUNI region and as thermal generation exits the region, and thus comply with the grid reliability standards.
- There are several inter-related voltage management issues mitigated by the project, including transient over and under voltage, long-term voltage collapse, and high steady-state voltages during low-load periods. The Waikato DRD primarily mitigates transient over-voltage, but also helps mitigate high steady-state voltages.

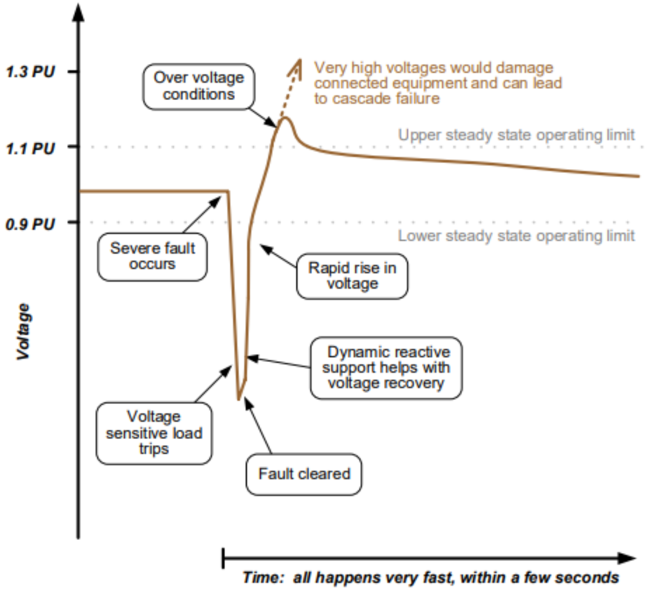
The Waikato DRD uses the resiliency method

- The Waikato DRD is a high-value BBI (>$20m) so uses the standard method.
- Uses the resiliency method as it is primarily to mitigate the risk of cascade failure of the power system.
- Not expected to have material market, reliability, ancillary service, or 'other' benefits (but these cannot be assessed for a resiliency BBI under the proposed TPM).



Benefit is to mitigate risk of cascade failure

- For a resiliency BBI that mitigates a localised high-impact, low probability risk, charges are allocated to the region(s) in which the risk is being mitigated.
- The Waikato DRD mitigates the risk of cascade failure, so – under the proposed TPM – charges are allocated to all offtake customers in the island in which the risk is mitigated (the North Island). Given the BBI mitigates the risk of cascade failure affecting the North Island, all load customers in the North Island benefit despite the fault being initiated in the WUNI region.



Charges are allocated based on historical offtake

- For a resiliency BBI, charges are allocated based on historical average offtake in the five capacity years (Sep – Aug) immediately preceding the decision to proceed with the BBI.
- Compared to the existing TPM, North Island load customers would pay more for the BBI, and South Island load customers less. Generators with offtake in the North Island may pay a very small allocation, but are largely unaffected.
- The allocations of the five largest beneficiaries is shown. Full allocations are in Appendix E of our reasons paper.

Customer	Allocation
Vector	37.9%
Powerco	19.2%
WE*	10.0%
Unison	5.8%
Northpower	4.8%

Benefit-based charge – simple method

Simple method

- Simple method used for low-value investments (<$20m)
- Proposed approach to:
  - Cater for a large number and wide variety of low value BBI
  - Balance precision and practicality
  - Be administratively simple and lower cost to implement than the standard method
  - Allocate between primary beneficiaries broadly in proportion to expected positive net private benefits
- Regional allocation model with regional allocation factors using a proportional allocation of quantities

Modelled regional definition

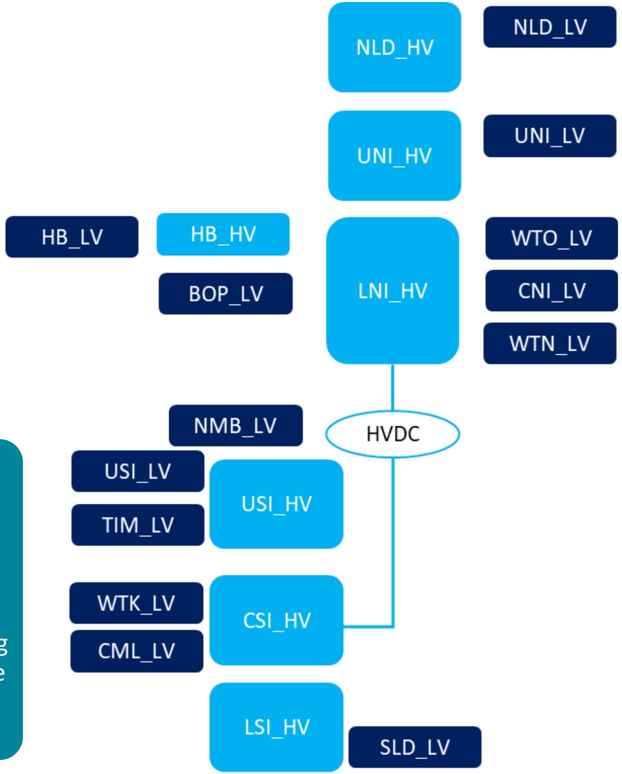
- Use characteristics of electric power transfer and grid flows to identify regions where primary beneficiaries are broadly aligned
- Use 5 years of historical half-hourly data

At least 3 high voltage regions (including the HVDC)

Separate high voltage (>110kV) regions created where there is the largest region of prevailing power flows

Low-voltage (<= 110kV) regions are separate regions as these tend to supply more localised regions

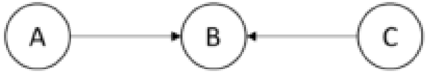
Separate low voltage networks can arise if they connect to different HV regions or are not considered a strong connection relative to the parallel HV region



Primary beneficiaries

- Primary beneficiaries considered relative to the power flow transfer between regions

Region	Primary beneficiary
A	Ga, La, Lb, Lc
B	Ga, Gb, Lb, Lc
C	Ga, Gb, Gc, Lc

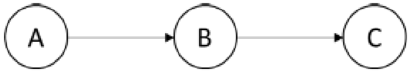


Region	Primary beneficiary
A	Ga, La, Lb
B	Ga, Gb, Lb, Gc
C	Lb, Gc, Lc

Region	Primary beneficiary
A	Ga, La, Gb
B	La, Gb, Lb, Lc
C	Gb, Gc, Lc

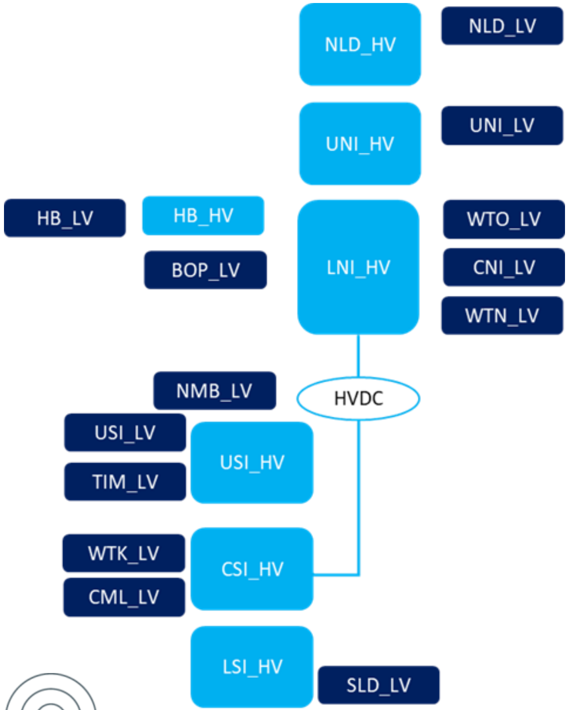
Allocation between primary beneficiaries

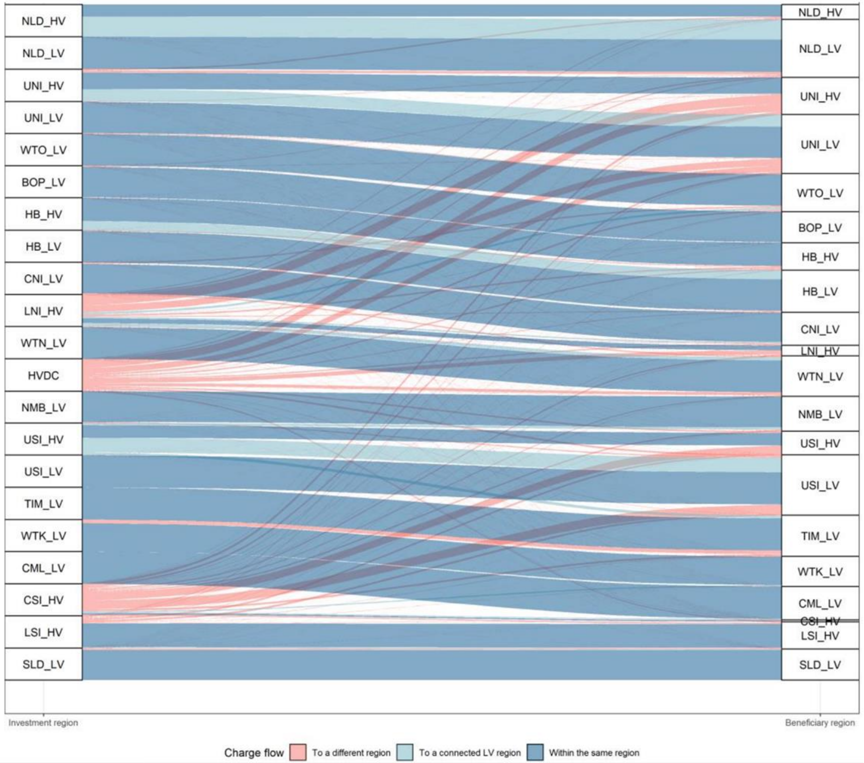
- Costs in each region allocated to primary beneficiaries based on the proportional allocation of quantities



		A	B	C
	Primary beneficiaries	Ga, La, Lb, Lc	Ga, Gb, Lb, Lc	Ga, Gb, Gc, Lc
Allocation	Ga	$\frac{G_a}{(G_a + L_a + F_{a\_b})}$	$\frac{F_{a\_b}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{F_{a\_b}}{G_b + F_{a\_b}}\right)$
	Gb	0	$\frac{G_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{G_b}{G_b + F_{a\_b}}\right)$
	Gc	0	0	$\frac{G_c}{(G_c + L_c + F_{b\_c})}$
	La	$\frac{L_a}{(G_a + L_a + F_{a\_b})}$	0	0
	Lb	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{L_b}{L_b + F_{b\_c}}\right)$	$\frac{L_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	0
	Lc	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{F_{b\_c}}{L_b + F_{b\_c}}\right)$	$\frac{F_{b\_c}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{L_c}{(G_c + L_c + F_{b\_c})}$

Regional allocations for offtake primary beneficiaries

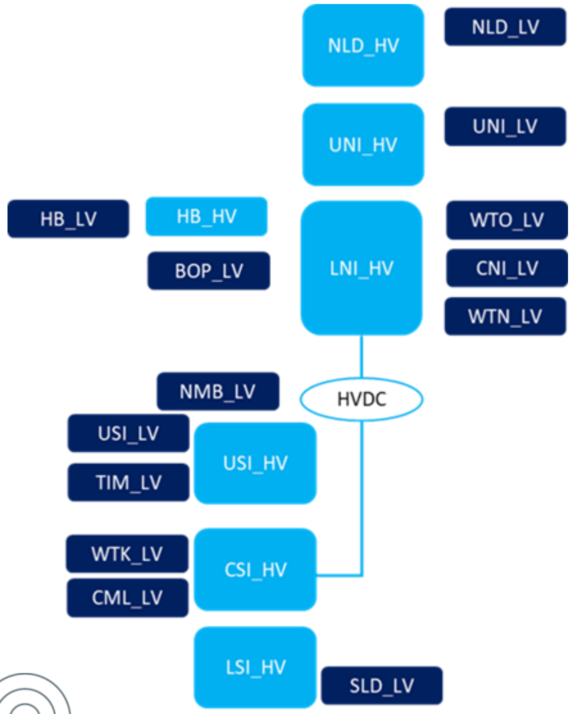


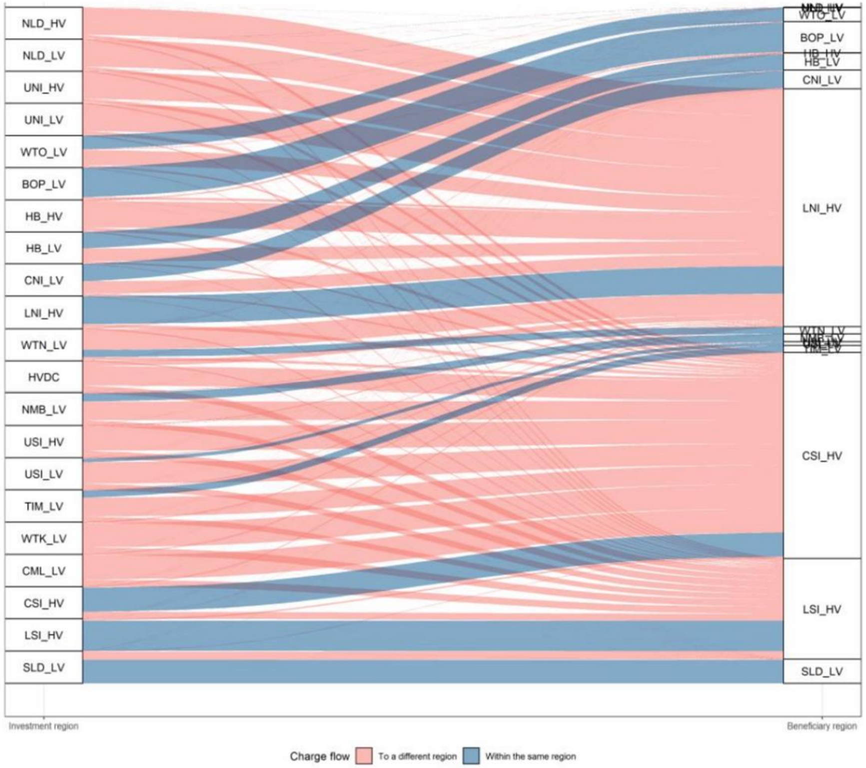


(Source: Figure 33* from EA Proposed TPM Consultation Paper)

(* Based on Transpower data)

Regional allocations for injection primary beneficiaries

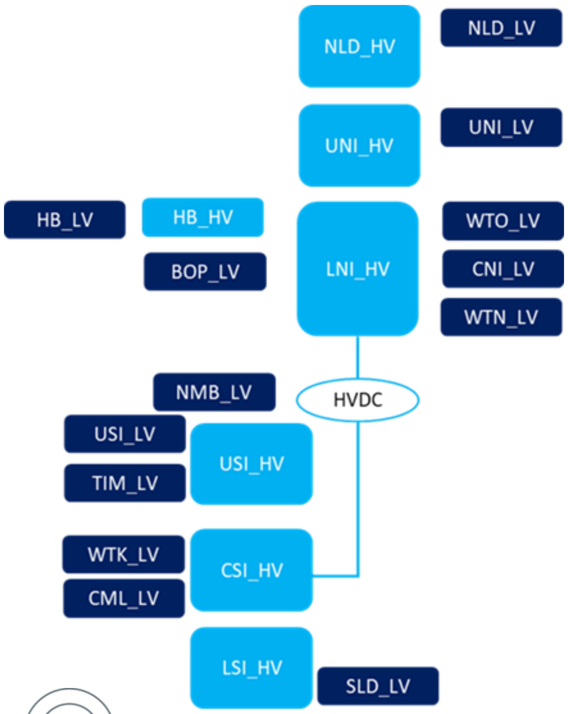


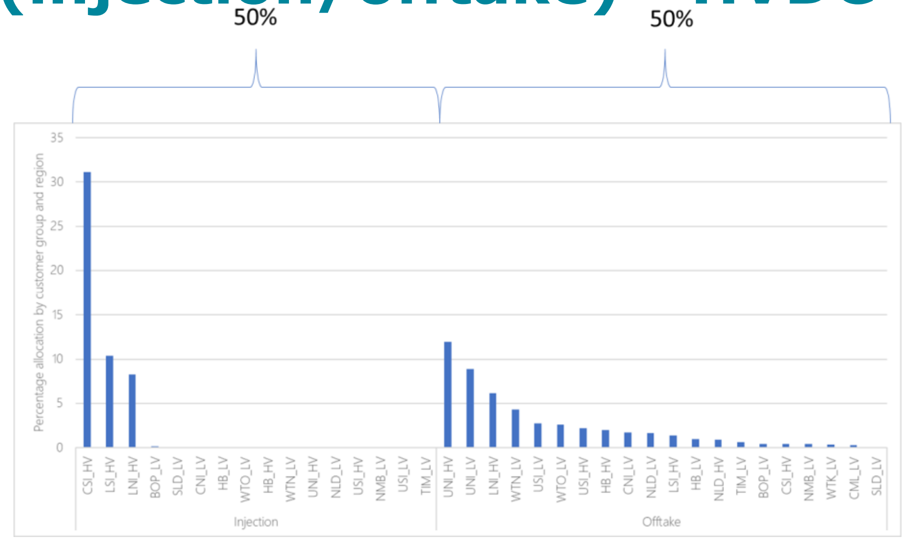


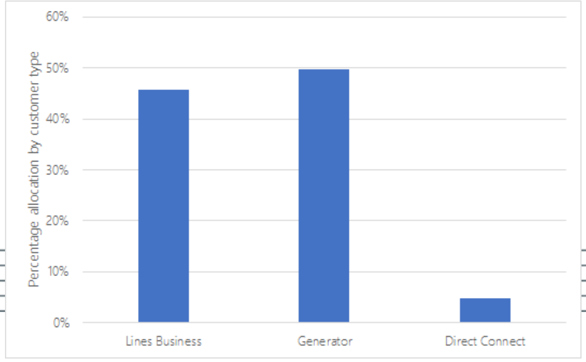
(Source: Figure 34* from EA Proposed TPM Consultation Paper)

(* Based on Transpower data)

Example allocation (injection/offtake) - HVDC







Weighting between aggregate offtake and injection beneficiaries

- Roughly equal allocation between injection and offtake (on aggregate)
- Simple method approach allows for a weighting factor between offtake and injection
- Propose for initial weighting factor of 1 (i.e. initial allocation would be roughly equal between aggregate injection and offtake)
- Use injection/offtake allocations from at least 10 standard method BBIs to inform future weighting factor