TRANSMISSION PRICING METHODOLOGY (TPM) REVIEW

TPM options working paper

Initial release

16 June 2015

COMPETITION • RELIABILITY • EFFICIENCY

Charges under current TPM

The current TPM has three main charges:

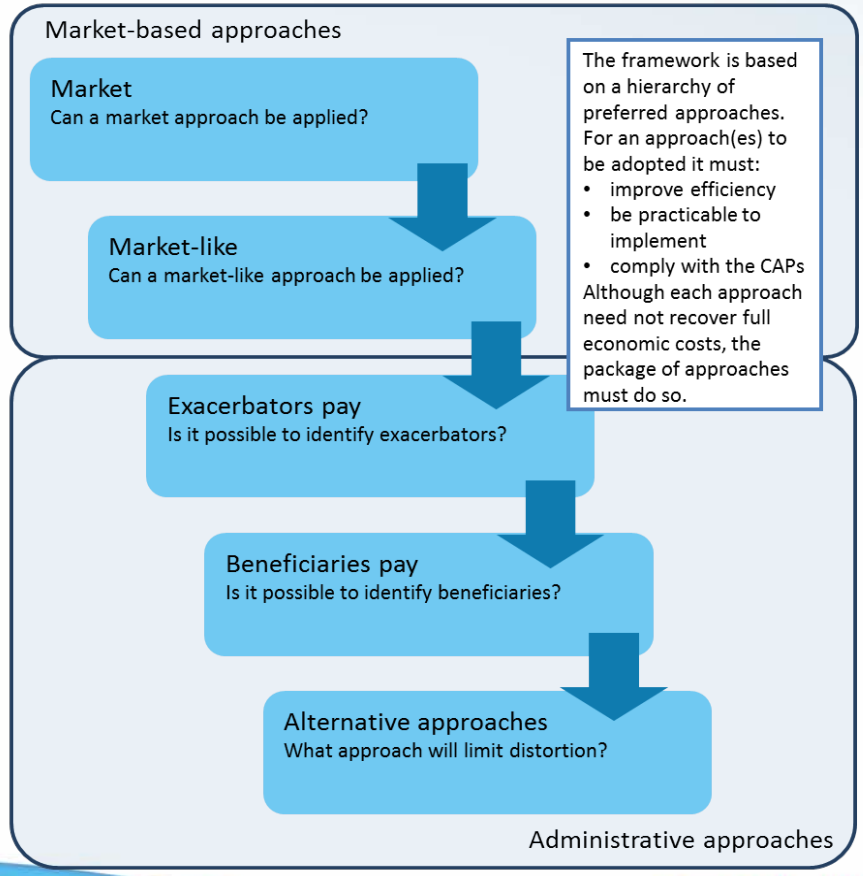
Charge	Paid by	Pays for	2015/16 amount ($m)
1. Connection	Parties connecting to the transmission grid (generators, EDBs, large consumers)	Connection assets	$127.7
2. HVDC	South Island generators only	Inter-island high voltage direct current (HVDC) link	$149.9
3. Interconnection	Mainly EDBs, large consumers	Non-connection meshed alternating current part of the grid	$632.2

Four main problems with current TPM

- It is not adaptive and sends the wrong price signals
- It does not appear to be cost-reflective
- It fails to support the discovery of efficient transmission investment
- It is not durable

The choice of options is guided by the decision-making and economic framework

- The Authority developed in 2012 a decision-making and economic (DME) framework to guide decisions on an efficient TPM



Overview of Authority's approach: the key charging methods

	Base option	Base option + LRMC	Base option + SPD
	Connection charge Deeper connection charge Area-of-benefit (AoB) charge Capacity-based residual charge		

Note: the LCE credit and kvar charge are relatively technical adjustments and are omitted to simplify this presentation

Overview of Authority's approach: the key charging methods

	Base option	Base option + LRMC	Base option + SPD
	Connection charge	Connection charge	Connection charge
	Deeper connection charge	Deeper connection charge	Deeper connection charge
		Long run marginal cost (LRMC) charge	
			SPD-based charge
	Area-of-benefit (AoB) charge	Area-of-benefit (AoB) charge	Area-of-benefit (AoB) charge
	Capacity-based residual charge	Capacity-based residual charge	Capacity-based residual charge

Note: the LCE credit and kvar charge are relatively technical adjustments and are omitted to simplify this presentation

Overview of Authority's approach: the key charging methods

	Base option	Base option + LRMC	Base option + SPD
Application A: new charges apply to both new and existing assets but we are considering whether to phase them in (called transition options)	Connection charge Deeper connection charge	Connection charge Deeper connection charge Long run marginal cost (LRMC) charge	Connection charge Deeper connection charge SPD-based charge
OR	Area-of-benefit (AoB) charge	Area-of-benefit (AoB) charge	Area-of-benefit (AoB) charge
Application B: new charges apply only to new assets; hence automatically phases in	Capacity-based residual charge	Capacity-based residual charge	Capacity-based residual charge

Note: the LCE credit and kvar charge are relatively technical adjustments and are omitted to simplify this presentation

Deeper connection charge

- Included in all three options
- Extends connection deeper into the grid by identifying assets used predominantly by a small number of parties – does this with flow tracing and the Herfindahl-Hirschman Index (HHI)

Why considering this charge?

- In principle, where assets are used predominantly by only a small number of parties they should be able to contract with Transpower for the assets, ie the charge is market-like (same as connection charge)

Application features

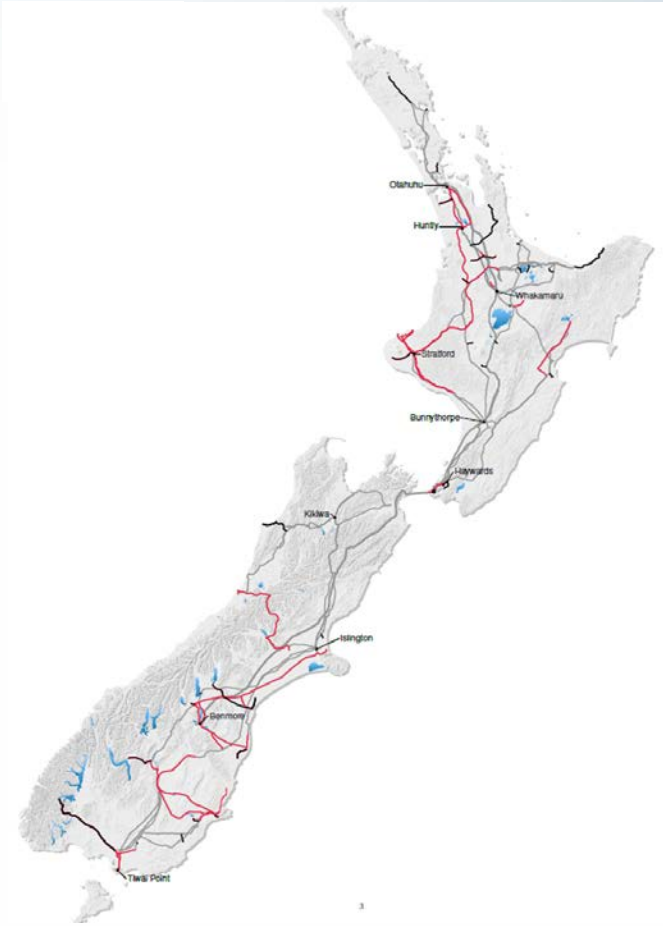
- Deeper connection charge would apply where flows over an asset are equivalent to 2 or fewer users
- Propose to re-calculate coverage of deeper connection charge every 5 years
- Propose charges would be allocated according to anytime maximum demand or injection at relevant connection node
- Under Application B: would apply only to new assets

Assets subject to deeper connection charge under Application A

Deeper connection assets shown in red

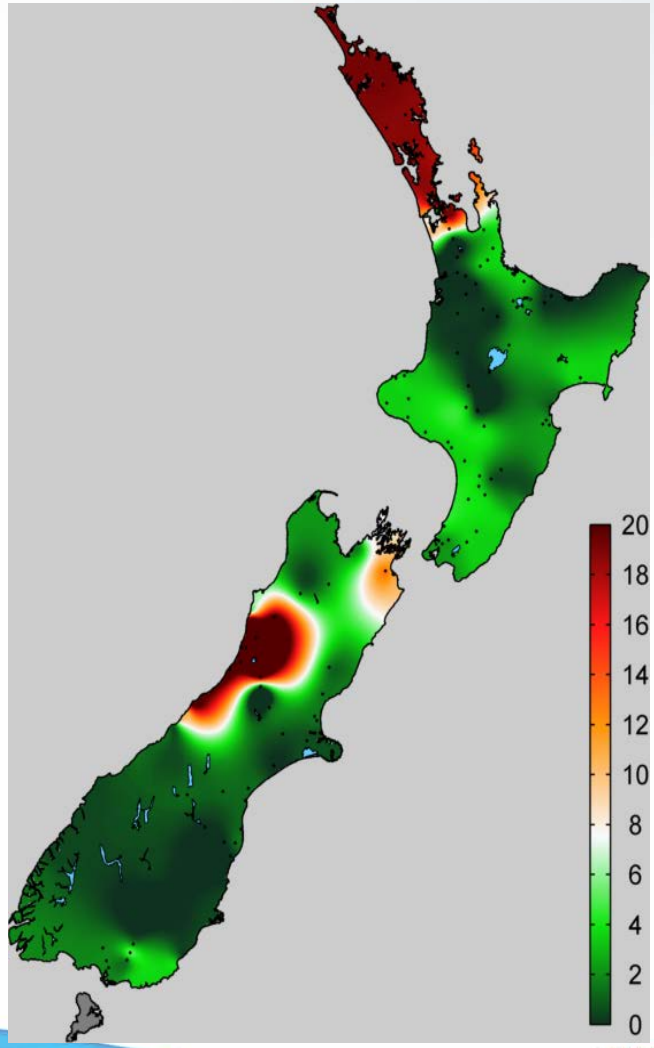
Load

Generation



Incidence of deeper connection charge under Application A

Load, fully variblised, $/MWh



LRMC charge

- Included only in Base Option + LRMC
- Uses the marginal incremental cost (MIC) definition of LRMC as that's the most efficient approach

Why considering this charge?

- Setting prices based on LRMC when congestion starts occurring provides signals for efficient use of grid assets when additional investment is being planned

Application features

- Propose to apply when future investments would not be covered by the deeper connection charge
- Applies to both generation and load
- Applied according to net capacity required by participant during congestion
- Would recover relatively little revenue initially – reflects current level of planned investment

Area-of-benefit (AoB) charge

- Included in all three options
- The AoB charge would be allocated to parties based on their share of the benefits anticipated at the time investment decisions are made (we're considering a periodic adjustment mechanism for this charge)

Why considering this charge?

- Promotes efficient investment by targeting charges to parties that benefit from a grid asset rather than smearing the charges evenly across all parties
- Similar to charge applied in other jurisdictions, eg MISO in US

Application features

- The AoB charge is an extension of the GIT-based charge, as suggested by some submitters
- Applies to both generation and load
- Would apply (under Application A) to
  - Investments after 28 May 2004 > $50m
  - Assets or investments approved or commissioned (or both) after guidelines issued> $20m (ie major capex), and possibly Pole 2

SPD charge

- Included only in Base Option + SPD
- The SPD approach allocates charges to parties based on their share of the benefits they actually receive from a grid investment

Why consider this charge?

- Same reason as for AoB charge, but the SPD approach adapts automatically to changes in grid use, so no need for a special adjustment mechanism (c.f. AoB charge)

Application features

- The SPD charge would be the same as proposed in the beneficiaries-pay working paper except
  - Net rather than gross benefit
  - Monthly capping (previously favoured daily capping)
  - Charges to distributed generation based on net rather than gross injection
  - Calculated and set on past data, so the charge is known in advance of being levied
- Applied before AoB charge

Residual charge – capacity based

- Included in all options
- This is a ‘postage stamp’ charge on load only. Not applied to generators as they would variablise it (allocatively inefficient)

Why considering this charge?

- Need a residual charge to ensure full revenue recovery for Transpower
- The capacity-based approach better promotes efficient investment and use of the transmission system c.f. a regional coincident peak demand (RCPD) or MWh charge

Application features

- Applied on basis that seeks to reflect connection capacity
  - Anytime maximum demand (AMD) for industrial consumers
  - Deemed capacity for electricity distribution business – sum of nominal capacities of active ICPs in network area (based on metering category code)
  - Note: not charged to retailers

Options are based on framework

DME framework		Base Option	Base Option + LRMC	Base Option + SPD
Market	LCE credit	✓	✓	✓
Market-like	Existing connection charge	✓	✓	✓
	Deeper connection charge	✓	✓	✓
	LRMC charge		✓	
Exacerbators-pay	kvar charge	✓	✓	✓
Beneficiaries-pay	SPD charge			✓
	AoB charge	✓	✓	✓
Alternative approaches	Capacity-based residual charge	✓	✓	✓

Two possible applications of options

To address concerns with applying new charges to existing assets, there are two possible applications of charges:

- **Application A:** This would involve applying new charges to both existing and new assets and investments
- **Application B:** This would involve applying new charges to recover the costs of new assets/investments only, with all other costs recovered through the existing charges, ie the connection, interconnection and HVDC charges

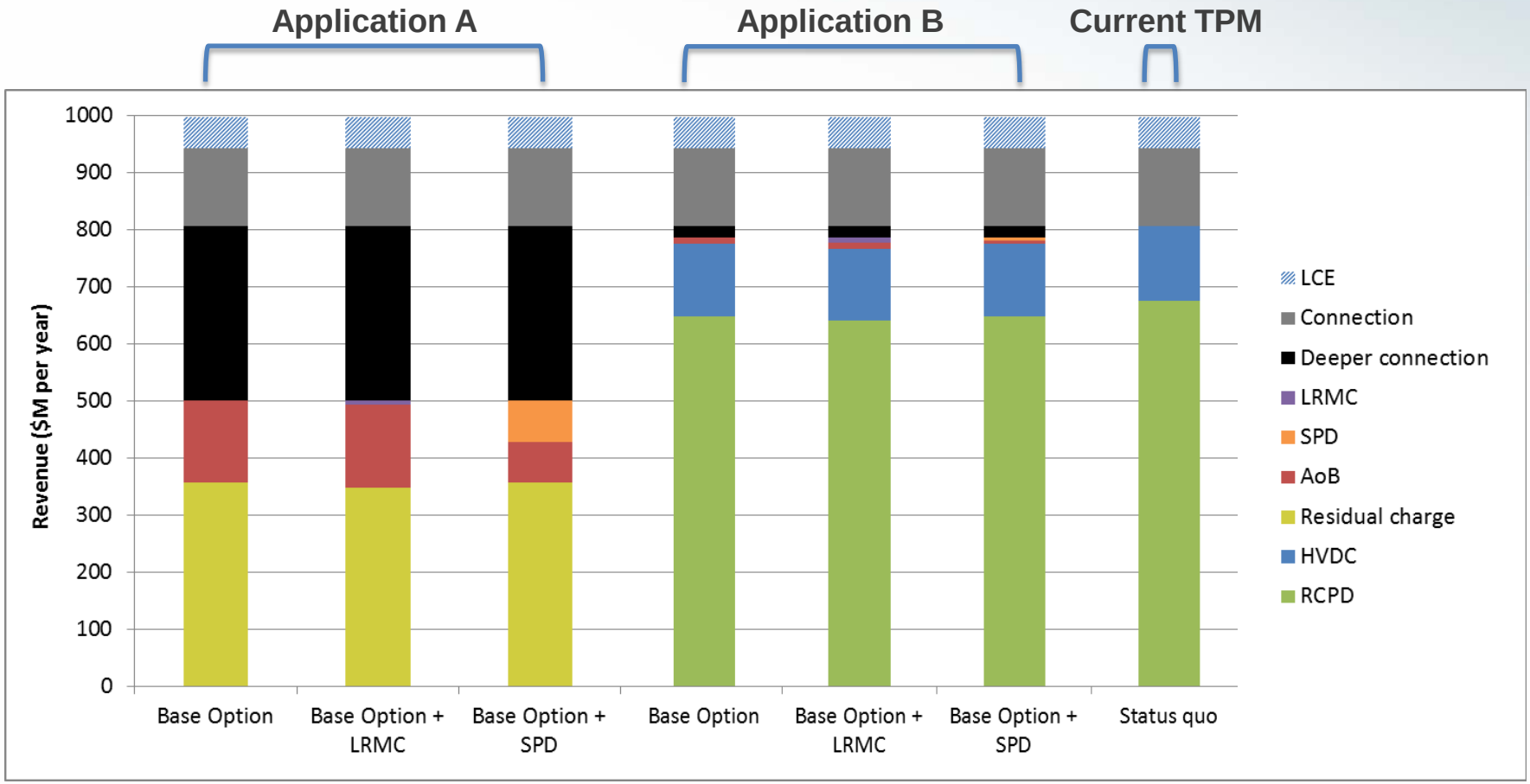
Charges under Application A and B of options

Charge	Option	Application A (New charges apply to both existing and new assets)	Application B (New charges apply only to new assets)
Deeper connection charge	All options	All eligible existing and new assets	Only to new assets
AoB charge	All options	Post-2004 investments above $50m, post-new guidelines investments above $20m, and, potentially Pole 2	Only to new investments
SPD charge	Base Option + SPD only	Post-2004 investments above $50m, post-new guidelines investments above $20m, and, potentially Pole 2	Only to new investments
Residual charge	All options	Capacity-based charge to recover residual revenue	Recover residual HVDC revenue through current HVDC charge Recover remaining residual revenue through current interconnection charge - but all load customers must pay *at least* variable cost

- Application of LRMC and kvar charges is same under both charges – new investments

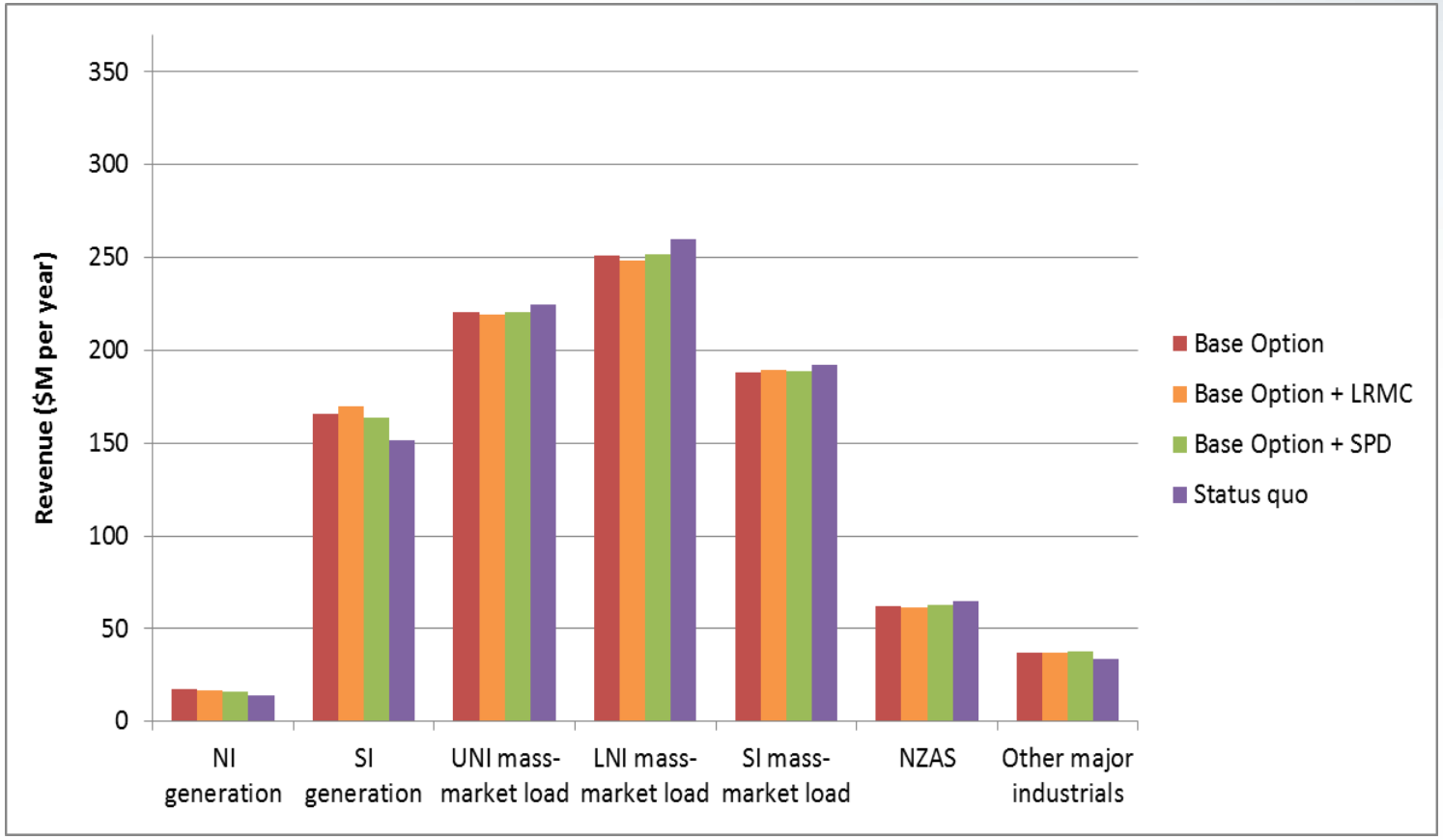
The impact on customer groups and regions is predominantly driven by (1) choice of Application A vs B and (2) the design of the deeper connection and residual charges

Modelled average of 2017-2019 years



Application B has similar charges to current TPM (but only initially)

Estimated TPM charges for customer groups for 2017-2019 years ($M per year)



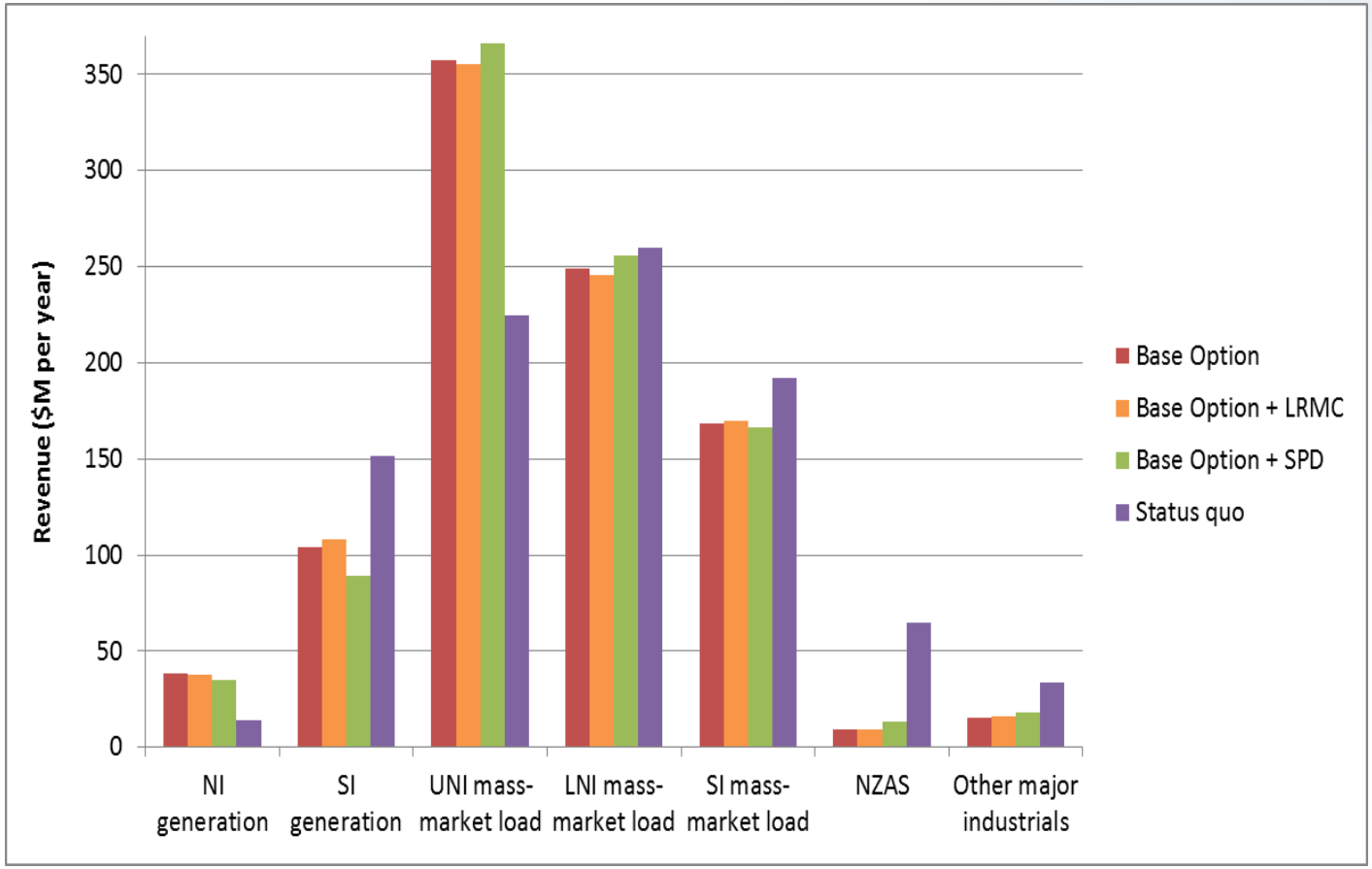
UNI = Upper North Island

LNI = Lower North Island

NZAS = NZ Aluminum Smelters

Application A shifts charges from industrial consumers and SI generation to UNI consumers and NI generation

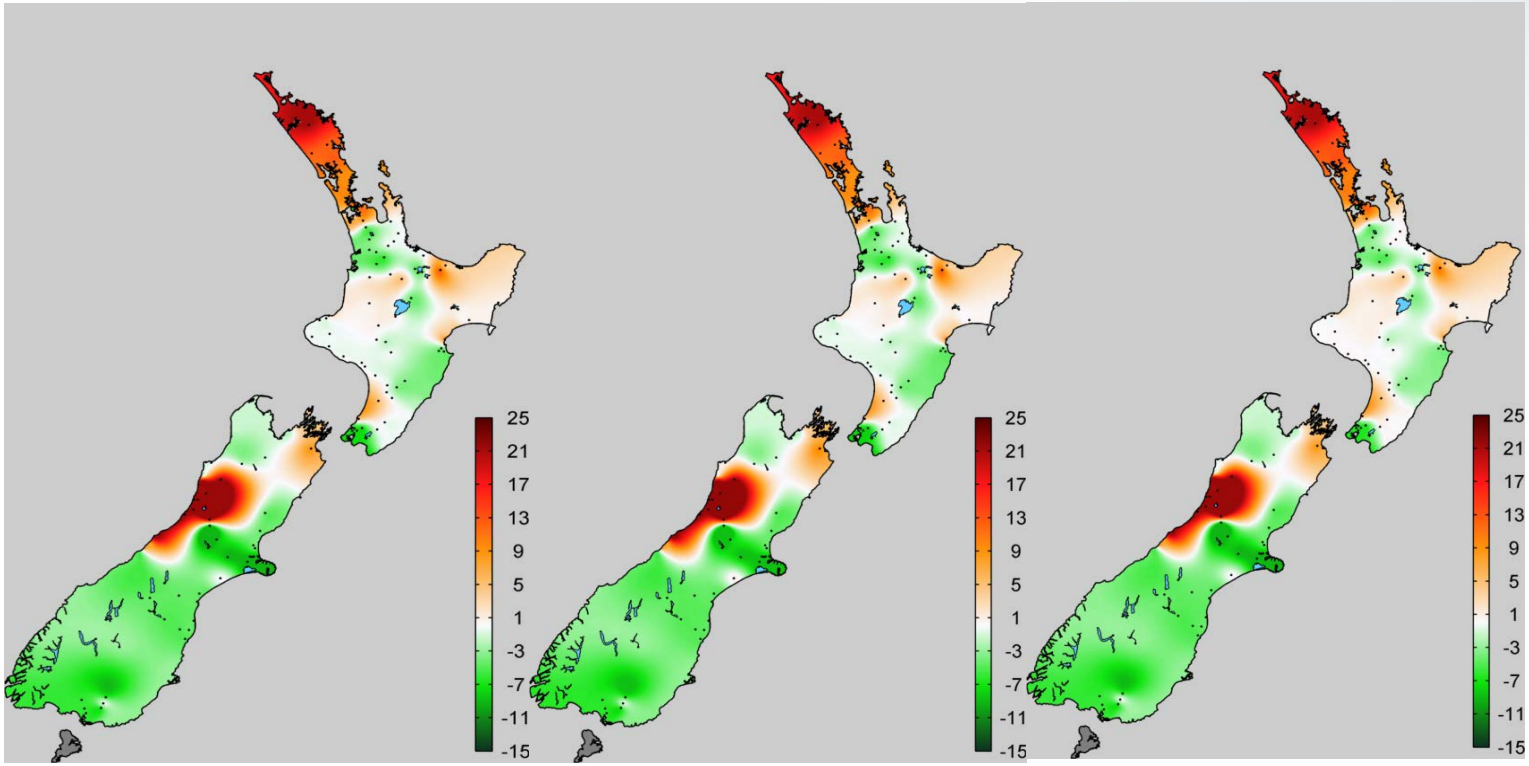
Estimated TPM charges for customer groups for 2017-2019 years ($M per year)



Regional distribution of transmission charges relative to existing charges under Application A (assuming no transition arrangements)

Estimated TPM charge rates for network areas for 2017-2019 years ($/MWh)

Base Option | Base+LRMC | Base+SPD



Effect of Application A on household electricity prices

- Without any transition arrangements, the percentage change in household electricity prices in network company (EDB) areas is estimated to be:
  - **+10%**: Top Energy and Westpower
  - **+4.5%**: Counties Power, Electra, Marlborough Lines, Northpower and Vector
  - **No change:** Aurora Energy, Buller Electricity, Eastland Networks, Electricity Ashburton, Horizon, Mainpower, Network Tasman, Powerco, Scanpower, The Lines Company, Unison (including Centralines) and WEL Networks
  - **- 2%**: Alpine Energy, Network Waitaki, Orion, PowerNet (including associated companies), Waipa Power and Wellington Electricity

It's important people consider the benefits they're receiving from grid upgrades, not just the higher charges

Higher transmission charges to parties reflect the higher benefits they receive from grid upgrades

- Provided upgrades are approved only when their economic benefits > economic costs, the parties paying higher charges from grid upgrades should be better off: their increase in benefits > their increase in charges

But moving to a more efficient TPM will create inevitable tensions

- Under **Application A** the parties/ regions that are expected to have transmission price increases are generally the beneficiaries/ causers/ users for large recent transmission investments (for example Auckland, Northland)
- Under **Application B**, there would be very little change across parties/ regions in the short term because the new charging regime would only apply to new assets

The transition to a more efficient TPM can be managed

- Under the proposed transition/capping options for Application A, the change in charges across regions/parties would be more muted

Transition options for application A

Four transition options

1. Capping rates of transmission charges to EDBs at upper quartile of all pre-capped rates, ie about $22/MWh – funded from other EDBs

2. Capping increase in transmission charging rates at $12.5/MWh per year, ie approximately 5% of a typical domestic retail tariff – funded from other EDBs

3. Capping annual increase in transmission charging rates at 20% of current transmission charge (compounded annually) for load customers – funded through existing charges on load

4. Phasing in deeper connection, AoB and SPD charges on pre-2017 assets over 5 years for load customers – funded through phasing out existing charges

Stakeholder engagement and key milestones

Milestone/Action	Date
Initial release of options paper	16 June 2015
One-on-one meetings	June – July 2015
Workshops throughout country	Late June-early July 2015
Consultation on options paper closes	11 August 2015 (8 week consultation)