Transmission pricing methodology review: Second issues paper

Workshops

June 2016

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The purpose of the workshop

- The purpose of the workshop is to assist parties understand the Transmission Pricing Methodology (TPM) second issues paper including the cost-benefit analysis of the proposal
- We will note points made during the workshop but parties should still make any points they wish the Authority to consider in a written submission

Key points to note

- The proposal is for new guidelines for development of the TPM
    - In essence, the guidelines establish the categories of charges that will be specified in the TPM, and the categories of customers who will pay the charges
- If the Authority confirms the new guidelines, Transpower would develop the TPM according to the guidelines
    - In essence, the TPM sets out how the charges will be calculated and applied
- Under the Code, before deciding whether to include a new TPM in the Code the Authority must consult on it

Workshop structure

- Elaboration of the decision-making and economic framework
- Problem definition
- Proposal
- Indicative modelling
- CBA of proposal
- Next steps

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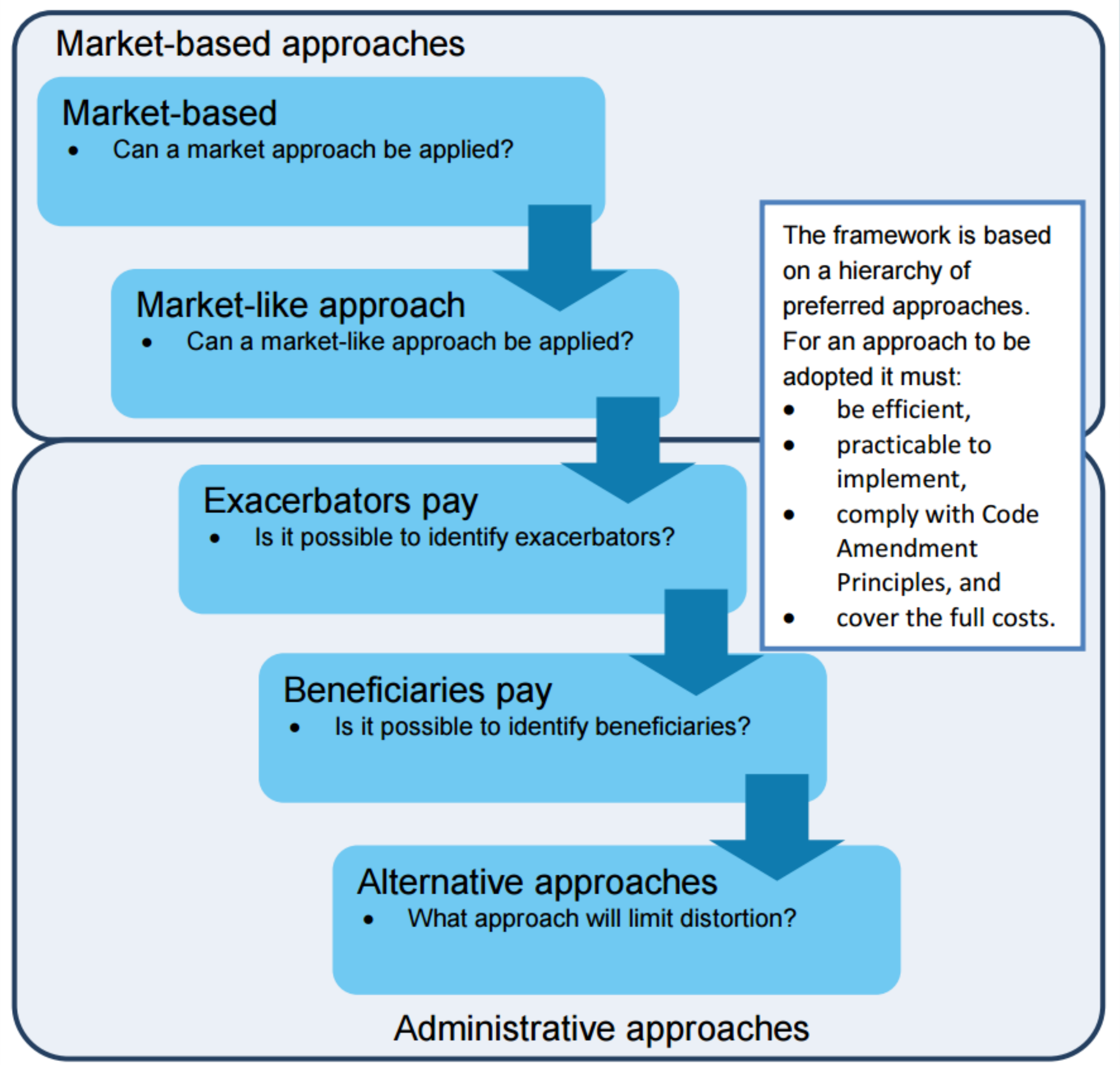
Decision-Making and Economic Framework



Have elaborated on the Framework in light of submissions

Elaboration of Decision-Making and Economic Framework

Key principle 1

- Prices should be:
  - service-based
    - cost of transmission services charged only to those receiving service
    - charges higher for higher levels of service
  - cost-reflective
    - price reflects cost of delivery of the service
- Implies parties getting service improvements from grid upgrades should pay full cost of upgrade
  - ensures their decisions factor in cost of upgrade
  - encourages efficient timing and location of investment

Key principle 2

- For shared services, charge parties:
  - at least incremental cost
  - no more than stand alone cost
- Already applies to connection services

Elaboration of Decision-making and Economic Framework

- For connection services, users:
  - face the short-run marginal cost (SRMC) of using the connection (losses and constraints)
  - rationally self-ration use to capacity until an upgrade is justified
  - co-optimise connection and other investment
  - support upgrades when benefit of upgrade exceeds its cost

Elaboration of Decision-making and Economic Framework

- Should apply similarly to upgrades of assets used to provide interconnected grid services:
  - Nodal prices encourage efficient use since include SRMC of grid use (losses and constraints)
  - To encourage efficient investment should:
    - charge users collectively cost of grid upgrade (cost-reflective)
    - charge in ways that don't undermine nodal prices by altering incentives for grid use
    - share cost among users in proportion to their share of benefits (service-based)
  - Result: users have:
    - "Skin in the game"
    - Incentive to:
      - Use the interconnected grid when benefits exceed cost of use
      - Locate investments in generation and load where overall costs are minimised
      - Advocate upgrade when benefit (including reduction in nodal prices) exceeds cost, and vice versa

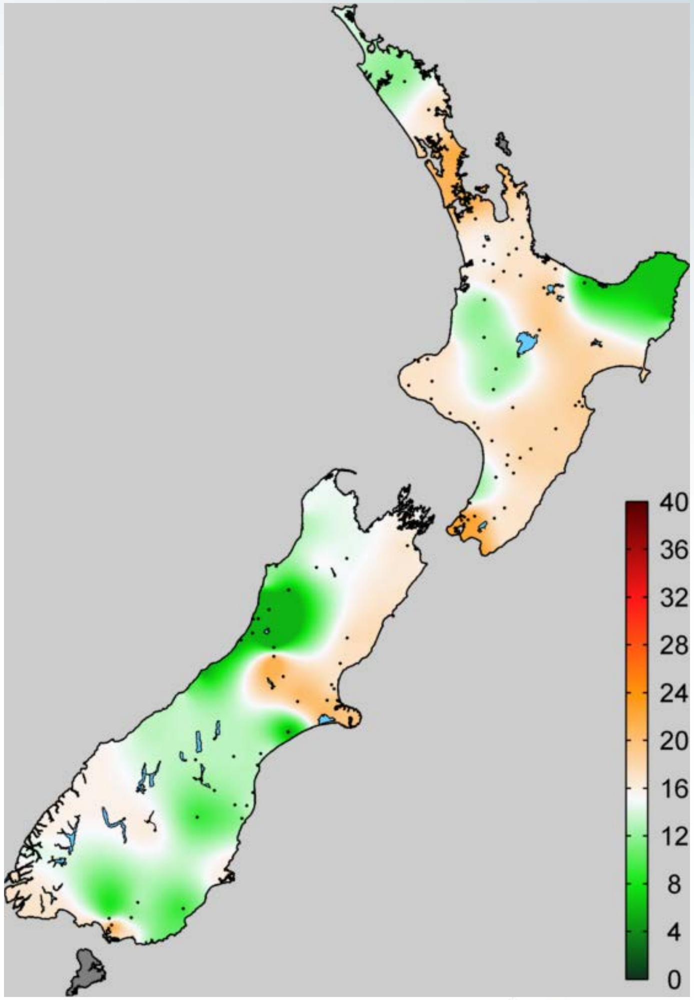
Problem Definition

- Connection charge market-like, so service-based and cost-reflective
- Interconnection and HVDC charges not service-based and not cost-reflective

<u>Example 1</u>

- Under service-based and cost-reflective pricing, expect lowest charges near generation
  - but consumers in the far North face lower interconnection charges than those in Waitaki and Taranaki

Current interconnection charges for distributors in fully variabilised terms ($/MWh)



Problem Definition

Example 2

Customers have:

- Paid for investments they or their customers don't benefit from significantly
- Not fully paid for investments they or their customers do benefit from

Region	Post-2004 investment*	Impact on Transpower revenue requirement	Actual increase in interconnection charges from 2008/9 to 2015/16	Actual tariff increase as a % of impact on revenue requirement
UNI	$1,342m	$201m	$87m	43%
LNI	$237m	$36m	$80m	225%
USI	$77m	$12m	$40m	343%
LSI	$81m	$12m	$40m	327%

*does not include HVDC or connection investment

Problem Definition

- Consequently interconnection and HVDC charges both cause inefficiency
- Both inefficiently discourage use of the grid when no congestion, because charges:
  - are based on *use* of the grid (regional coincident peak demand (RCPD) and South Island mean injection (SIMI) respectively)
    - encourage inefficient use of demand response (DR) and distributed generation (DG)
  - rise *after* grid investment, further discouraging use
- Both charges encourage inefficient investment
  - Inefficient use encourages inefficient investment in the grid
  - SIMI-based charge paid by South Island generators - encourages generation investment in NI but discourages generation investment where it may be needed eg upper South Island
  - RCPD-based charge encourages consumers to invest inefficiently (eg, in DG and DR)
  - Postage stamp nature encourages inefficient investment (eg, undergrounding, location of gas-fired generation)
- Postage stamp basis discourages participation in transmission investment decision making
- TPM is not durable:
  - not service-based and cost-reflective
  - people object to paying for things that don't provide a benefit to them

Proposing to replace two current charges with two new charges

- **Key changes**: proposing to:
  - Allocate the cost of grid investments to those that benefit from them; called the area-of-benefit (AoB) charge
  - Recover the remainder of Transpower's maximum allowable revenue through a broad based residual charge on load
- Retain connection charge ($128 million per year)

Two main current charges		Two main new charges
HVDC $150 million per year	→	Area-of-benefit $296 million per year
Interconnection $639 million per year		Residual charge $500 million per year
Prudent discount policy (PDP)		Expanded PDP

Overview of Authority's proposal: Main components

	Main components	Proposal
Beneficiaries pay	Connection charge (Access charge)	
Beneficiaries pay	Area-of-benefit charge (Access charge)	
	Residual charge (Broad base low rate charge)	

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Overview of Authority’s proposal: Main components

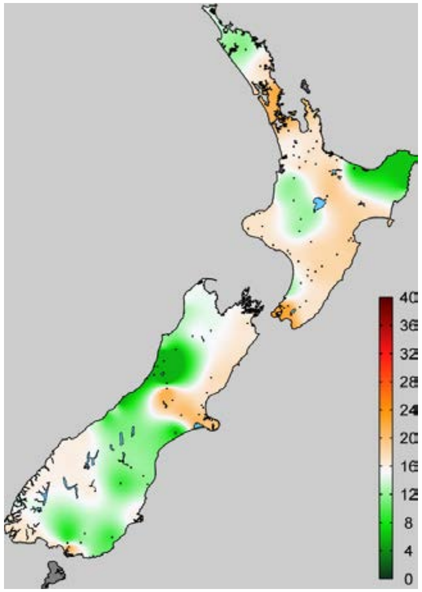
Beneficiaries pay

Main components	Proposal
Connection charge (Access charge)	▪ Retain the existing connection charge subject to possible inclusion of additional components
Area-of-benefit charge **(Access charge)**	▪ Applied to both load and generation ▪ Applied to new investment, replacement, refurbishment and upgrades ▪ To the extent practicable, parties would pay in proportion to their share of benefits ▪ A standard method would apply for new investments >$5m and for post 2004 investments > $50m and for Pole 2 o Rigorous determination of areas of benefit etc o Allows optimisation of asset values and marginal cost adjustment o Beneficiaries re-determined if material change in circumstances ▪ A simplified method for new investments <$5m
Residual charge (Broad base low rate charge)	▪ Applied to load customers only ▪ Allocated in proportion to share of historical physical capacity o Transpower may proxy physical capacity by using gross AMD in the 5 years prior to publication of TPM second issues paper ▪ Overhead and unallocated operating expenses are currently $198m o Proposing similar allocation to status quo but also considering a surcharge approach

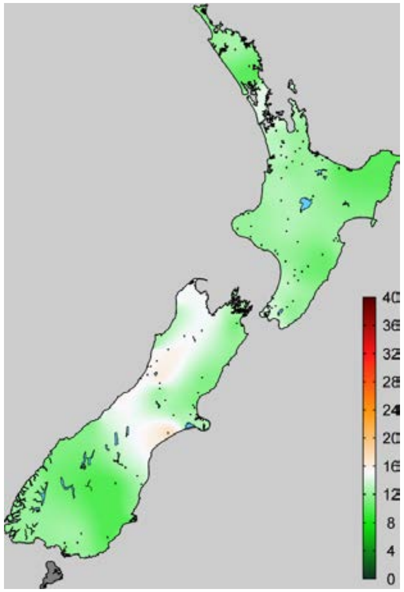
Proposal more cost-reflective with a more even residual

Indicative charges on distributors in fully variabilised terms ($/MWh)

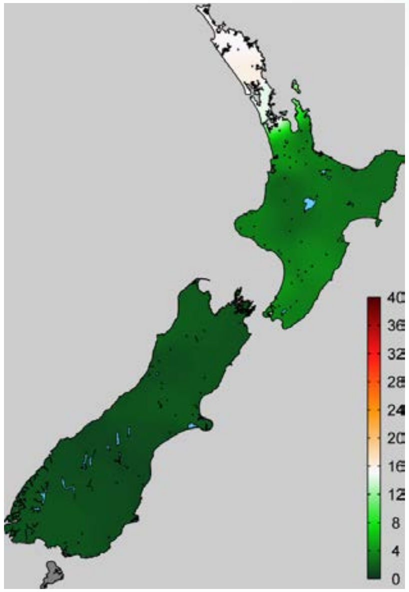
Current interconnection charge



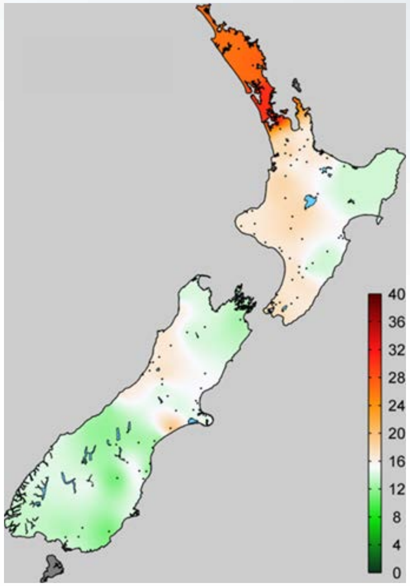
Proposed residual charge



Proposed area-of-benefit charge



Proposal (AoB and residual combined)

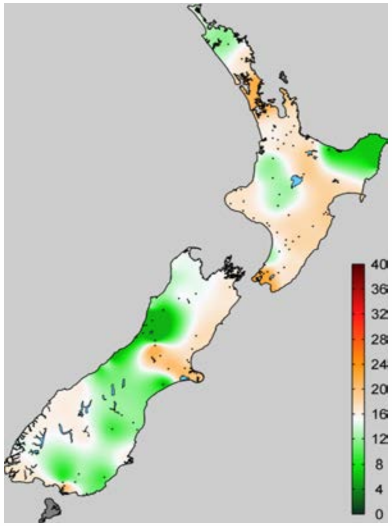


1. The AoB charge

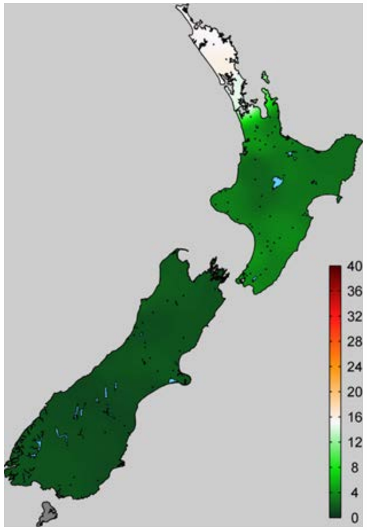
- The area-of-benefit (AoB) charge charges those that benefit from grid investments
- The AoB charge is service-based and cost-reflective, and easy to calculate once the benefits have been estimated

Indicative charges on distributors in fully variabilised terms ($/MWh)

Current interconnection charge



Proposed AoB charge



- The AoB charge would reduce costs to consumers over the long term by creating incentives for transmission investment to occur only when beneficiaries are willing to pay for it
- AoB charges used elsewhere, eg for investment decision-making in mid-west USA and New York state

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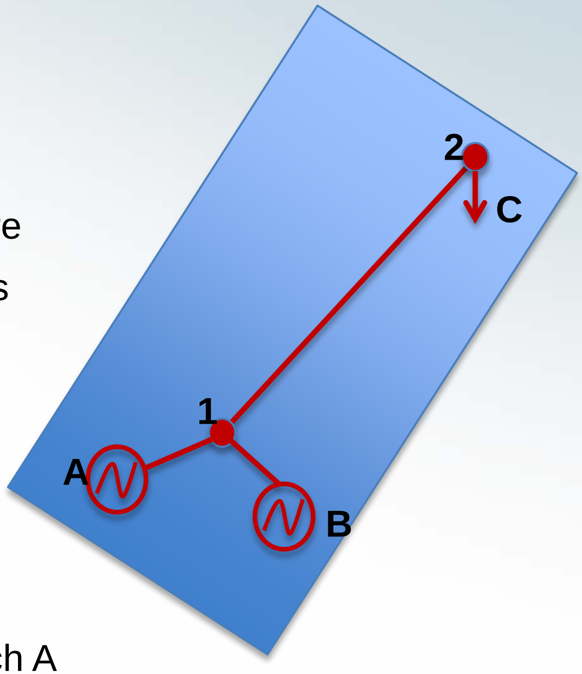
Calculation of the AoB charge

- Charge to each customer based on share of expected net positive benefits from an investment over its expected life
- Transpower would develop the methods for estimating net benefits and identifying areas of benefit – where at least one designated transmission customer is expected to receive a positive net benefit
- Four steps

1. Estimate the net benefits from the investment and where they accrue
2. Calculate the share of net benefits received by each area
3. Calculate the annual revenue to be recovered in relation to the investment
4. Charge to each area = annual revenue to be recovered x share of net benefits
    - If there is only one customer in the area – this is their charge
    - If there is more than one customer, the charge to each customer is in proportion to:
        - their aggregate expected positive net benefit, or if that is not practicable,
        - their share in the area of physical capacity (for load) or annual injection (generation)
            - capacity measure for load proposed to be the same as used for the calculation of the residual

Calculation of the AoB charge: Example

- Consider the following investment that relieves congestion in the transport of electricity from generation in area 1 to load in area 2
- Assume the value of the investment is $40m, and the annual revenue recovered is $4m
- Assume the estimated net benefits from the investment over its lifetime are $100m, of which area 1 receives $40m in net benefits and area 2 receives $60m
- Therefore the annual AoB charge to:
  - area 1 = $4m x 40% = $1.6m
  - area 2 = $4m x 60% = $2.4m = charge to load C
- The AoB charge for area 1 is shared between generators A and B, of which A accounts for 70% of average injection in the year for which charges are being calculated and B accounts for 30%
- Therefore:
  - A's charge = 70% x $1.6m = $1.12m
  - B's charge = 30% x $1.6m = $0.48m



Standard method and simplified method for calculating AoB charge

- Standard method would apply to investments (new investments, replacements, refurbishments and upgrades) > $5m
- Standard method would identify and charge *all* beneficiaries of investments, to the extent practicable
- Simplified method would:
  - apply to investments < $5m
  - to the extent practicable,
    a) be simple to apply and administer and
    b) be simple for a party paying the charge to ascertain why they are subject to the charge
  - identify expected beneficiaries unless this would compromise (a) and (b), in which case it would identify the customers expected to receive the majority of the positive net benefits
- Therefore expect simplified method to identify and charge the *main* beneficiaries of an investment

Valuation of Investments

- Propose using replacement cost to set AoB charge for new investments as well as replacement, refurbishment and upgrades
  - charges will better reflect the services actually provided by the asset
  - charges will rise over time if replacement cost increases
  - may adopt some other costing basis (eg, indexed historical cost)
  - charges will recover the capital cost and cost of capital over its expected life
  - charges will also include an allocation for maintenance and operating expenses
- Propose using depreciated historical cost (DHC) to set area of benefit charge for existing assets
  - assets valued at DHC under existing TPM
  - avoids charging twice for any asset
- Optimisation available for high value assets covered by the area of benefit charge if use has reduced significantly
  - for new assets, optimisation available after it has been in service for a number of years (10?)
  - for new assets, would be optimised to 'optimised RC'
  - for existing assets, would be optimised to 'optimised DHC'

Marginal cost adjustment

- Transpower to identify customers that benefit from a proposed investment and allocate the cost in proportion to the relative benefits
- Pre-investment, each customer can reduce its charges by credibly committing to reduce demand
  - e.g., by committing to install and operate DG
- Customer charges reduce by the marginal savings Transpower makes

Hypothetical example

- Suppose Transpower:
  - proposes to install a new transformer costing $10 million
  - assesses customer A as receiving 40% of the benefit, and its charges as $4 million (PV)
  - customer A installs DG which reduces its benefit to 20%
- This permits Transpower to install a smaller transformer costing $9 million
- Customer A's charges reduced to $3 million (PV) - the original assessed charge less Transpower's saving

2. Residual charge

- Propose to apply to load customers only
- Recovers all revenue not recovered by other TPM charges
- Not intended to provide a signal – therefore have sought to design it so that it would be difficult to avoid
- Would recover costs of any optimisation and PDP
- Propose to calculate/apply according to physical capacity, which could be one of the following:
  a) each customer's transformer capacity in the 12 months prior to 17 May 2016
  b) each customer's line capacity in the 12 months prior to 17 May 2016
  c) each customer's gross anytime maximum demand (AMD) in the 5 years prior to 17 May 2016
     - gross AMD = the customer’s AMD plus distributed generation and demand-side response
- Transpower would develop a proxy for (but unrelated to) physical capacity for new entrants
- Propose to provide that the physical capacity measure could be updated after a lag (eg, 10 years) with the lag period proposed by Transpower

3. The prudent discount policy

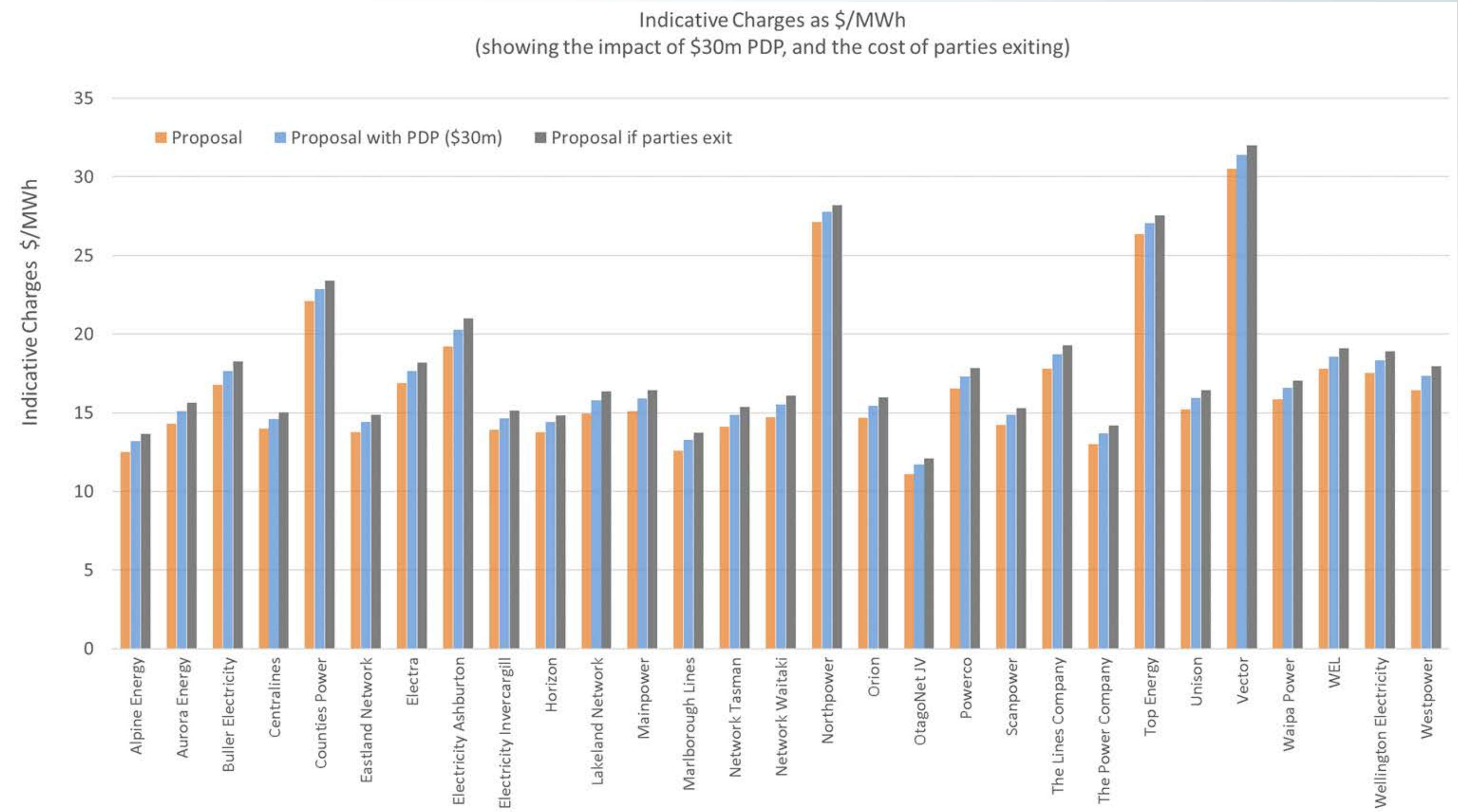
- Discount may apply for the expected life of relevant asset
- Prudent discount would apply as currently to parties who might inefficiently bypass the grid
- In addition load customers can apply for discount
  a) If privately beneficial to build generation to disconnect from the grid
  b) If materially at risk of closing down its NZ plant and so would disconnect from the grid
  c) If its transmission charges exceed standalone costs
  d) If a distributor has an embedded consumer in a similar circumstance to (b) and (c) above

Any prudent discounts for closure risk would be:

- available to customers for whom transmission charges are a material cost
- linked to key factors affecting closure decision, eg, world price of the customer’s output
- able to be reduced or suspended if the key factors relied on in granting the prudent discount change

Requesting submitter views on who should approve PDP applications under (b), (c) and (d)

PDP changes have a small impact on overall charges and avoid higher charges if parties exit



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Transpower would have three mechanisms to discount its transmission charges to customers

- There are several pragmatic aspects to the proposal to ensure that transmission pricing can adjust to ‘real world’ changes and continue to deliver good outcomes for consumers
- These adjustments reflect adjustments often seen in workably competitive markets

Mechanism	Description
Expansion of the prudent discount policy (PDP)	▪ Needed primarily because of the residual charge ▪ Reduces charges to an applicant when not doing so would <u>increase</u> costs to other transmission customers, and would not be efficient or for the long-term benefit of consumers ▪ Hence, achieves ‘win-win’ outcomes for the applicant, other transmission customers and consumers
Optimisation	▪ Specific assets subject to the standard AoB charge can be optimised if there is a substantial reduction in transmission demand in a region ▪ This avoids other transmission customers paying substantially higher prices as a result of the actions of a single large customer or local economic conditions
Revision of charges	▪ The standard AoB charge can be revised if there is a material change in circumstances

Overview of Authority's proposal: Additional components

	Additional components
Transpower to consider whether implementing these components would promote the statutory objective If don't propose, then desirable for Transpower to keep under review	Long run marginal cost (LRMC) charge
	Kvar charge
	Staged commissioning
	Charging for assets when other grid investments join those assets in a loop
	Allocation of operating and maintenance cost
	Code changes outside the TPM guidelines
	Loss and constraint excess (LCE) refunds
	Minimum power factors

Additional Component: LRMC Charge

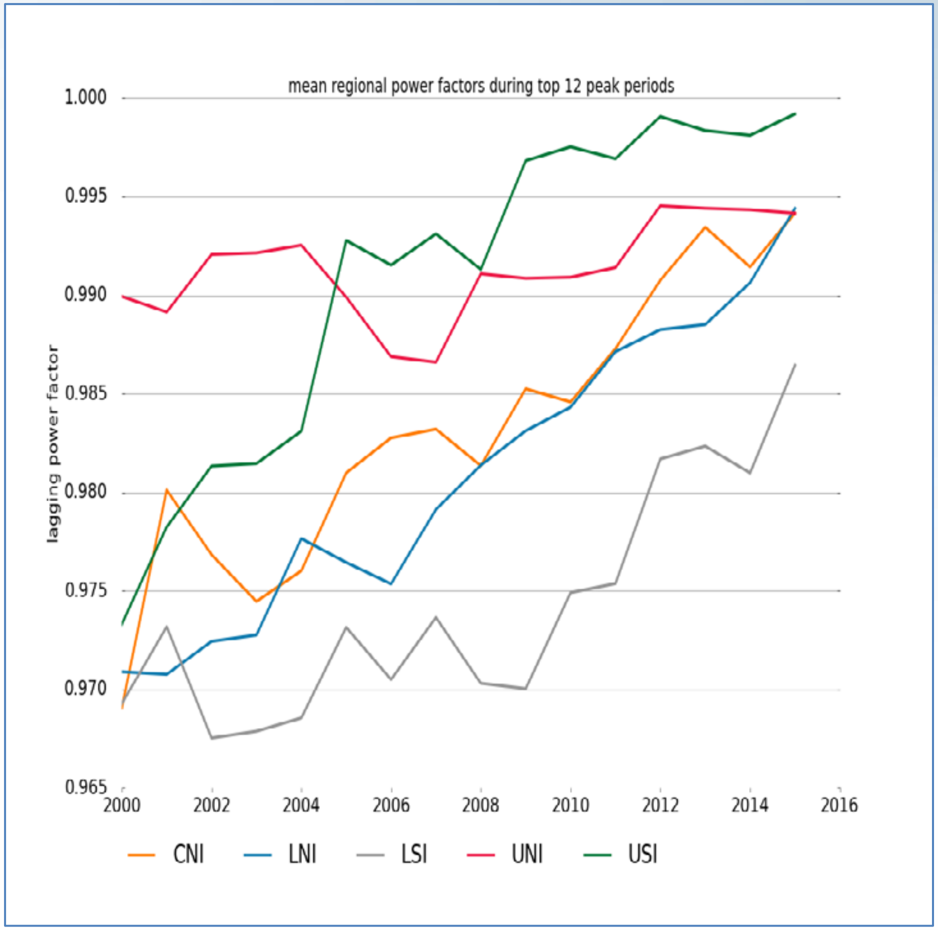
- Nodal prices normally account for the SRMC of using the grid (losses and constraints)
- As grid becomes congested, average nodal price downstream rises
- Eventually it rises enough to justify investing in the grid because of savings in losses and constraints
- However, if investment is triggered earlier by something else, may be efficient to ration grid use to defer the investment
- Authority's proposal allows Transpower option to introduce a charge to efficiently defer investment where nodal prices may be insufficient to signal the current or future costs of using the interconnected grid
- Would be up to Transpower to propose detailed design

Additional Component: LRMC Charge

- Authority expects that, if introduced, it would:
  - be applied where there is a risk that investment might be inefficiently undertaken
  - apply to peak congestion (assuming that is what is triggering the inefficient new investment)
  - be set to increase with increasing demand so that investment continues to be deferred
  - be removed when the new investment becomes efficient and is made
- Would need to be better than improving nodal prices

Additional Component: Kvar charge

- Transmission customers and their customers can cause a poor power factor
- Need static reactive support equipment to rectify this
- Propose a kvar charge so those who cause the need for reactive support equipment pay for it based on their kvar draw
- Transpower would determine where and when it would apply
- Propose to amend the Connection Code to relax the power factor requirement to 0.95 in all regions - currently, 1.0 for some regions
- August 2015 analysis suggests that power factors are continuing to improve
- So appears to be little immediate benefit from a kvar charge



Additional components relating to connection charge

- The connection charge recovers the costs of connection assets
- Propose to retain the existing connection charge because it is service-based and cost-reflective.
- Propose three additional components relating to connection charge for Transpower to consider:
  1. proposing a clarification to the TPM that, if assets are commissioned such that they meet the definition of connection assets, they are charged for as connection assets (even if they will ultimately be configured and charged for as interconnection assets)
  2. proposing a method to ensure that charges that apply to assets that provide connection services are not changed to another TPM charge due to the investment activity of a person other than Transpower
  3. including a method to allocate operating and maintenance costs for connection assets (and area-of-benefit assets) on an actual cost basis

Allocation of loss and constraint excess

- Currently loss and constraint excess (LCE) is allocated as follows:
  - the LCE arising in relation to connection, HVDC and interconnection assets is calculated using LCE guides
  - the LCE arising in relation to each category of asset is allocated to transmission customers in proportion to their transmission charges
- Propose to codify that:
  - LCE attributable to specific assets is allocated to customers that pay charges in relation to those assets in proportion to each customer's charges
  - any remaining LCE to be allocated to customers that pay the residual charge, in proportion to each customer's charges

Modelling of Charges

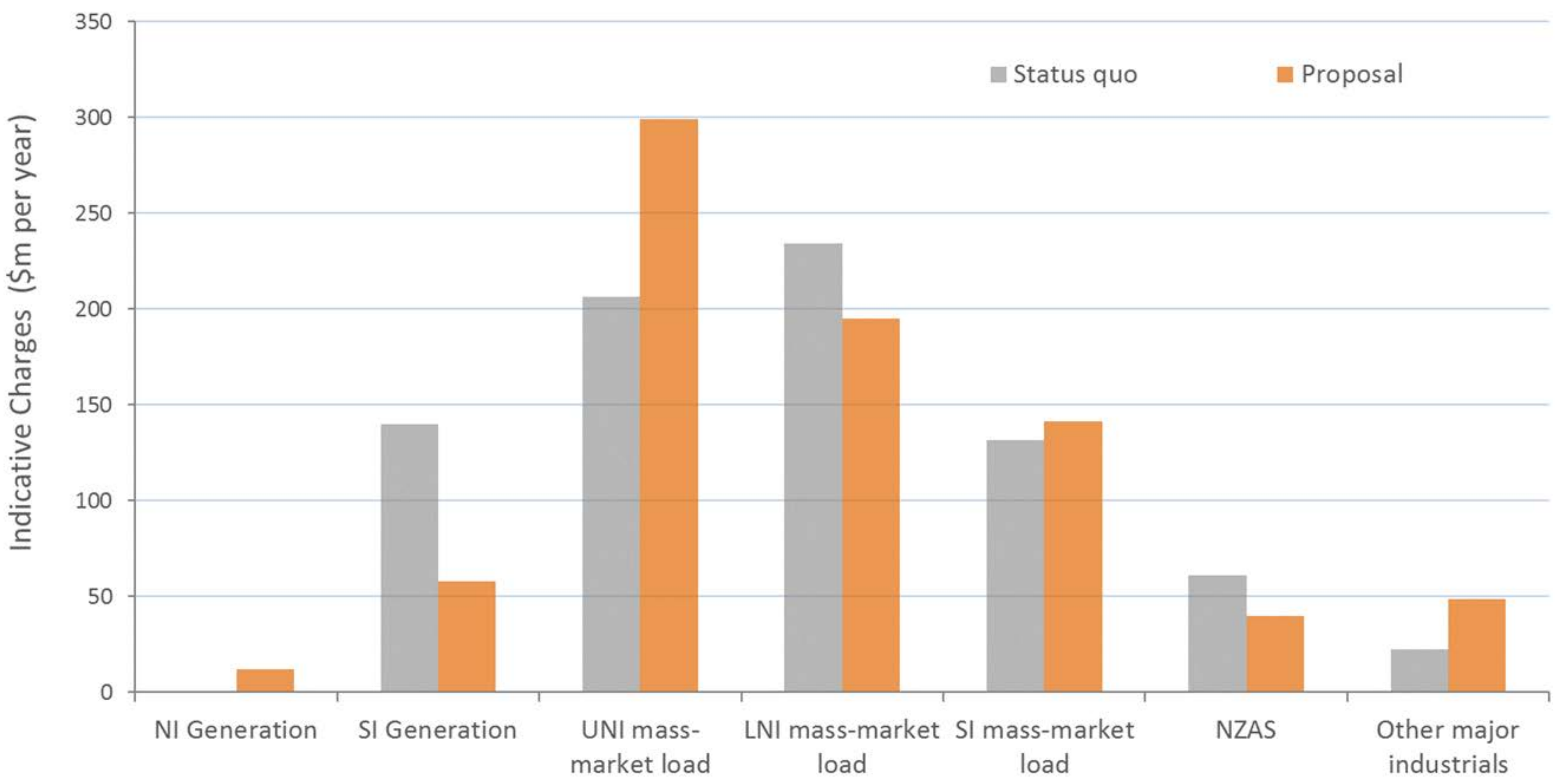
- The modelling is indicative only, to aid understanding
- The proposed TPM guidelines allow Transpower to use other methods, so actual charges may be substantially different
- The modelling of proposed charges uses market data from 2014, scaled to proxy a 2019 scenario
- The ‘Status Quo’ modelling uses the amended 2017 TPM applied to the same 2014→2019 scenario
- For the 2019 scenario:
  - two Huntly Rankine units remain in service and Southdown and Otahuhu B are removed
  - demand is increased by ~1% per annum
  - some other minor changes
- The 6 largest transmission investments are modelled in vSPD.
  - vSPD simulates market operations for each half-hour in a year
- If a party has benefitted overall from an investment, then they are charged a portion of that investment’s revenue requirement
- Smaller transmission investments are modelled using the “regional allocation method”
  - e.g. the OTA-GIS investment is allocated to loads Bombay & northwards

Modelling Assumptions

- The vSPD method is reliant on grid constraints being formulated
  - The constraints in the modelling are indicative, but imperfect (in practice, Transpower would have the resources to develop constraints more precisely)
- The modelling assumes all investments are independent. In reality, many will be inter-related.
- The modelling doesn't capture the full reliability benefits of the investments.
- Only one year is modelled, so the full range of hydrology is not represented, nor necessarily the exact average conditions (though 2014 had north and south HVDC flow)
- Connection charges are assumed to remain the same as the current charges
- The data underpinning the modelling may not be representative for all parties in 2019:
  - if there are material changes in demand (or grid configuration), and/or
  - where small embedded generation (i.e. not modelled) is a significant source of supply.

This may particularly affect smaller customers

Impact of the two main charges by customer group ($m)



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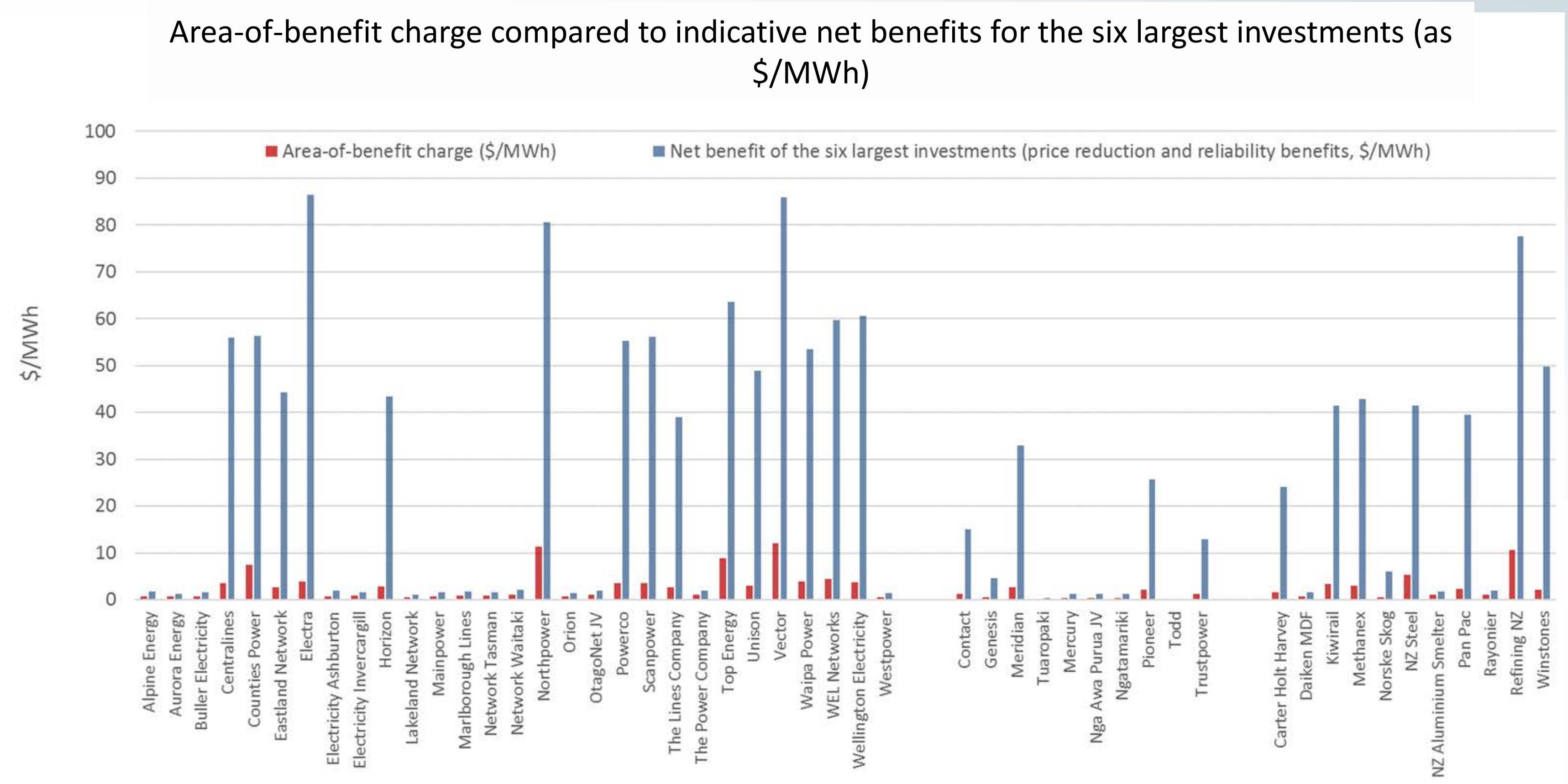
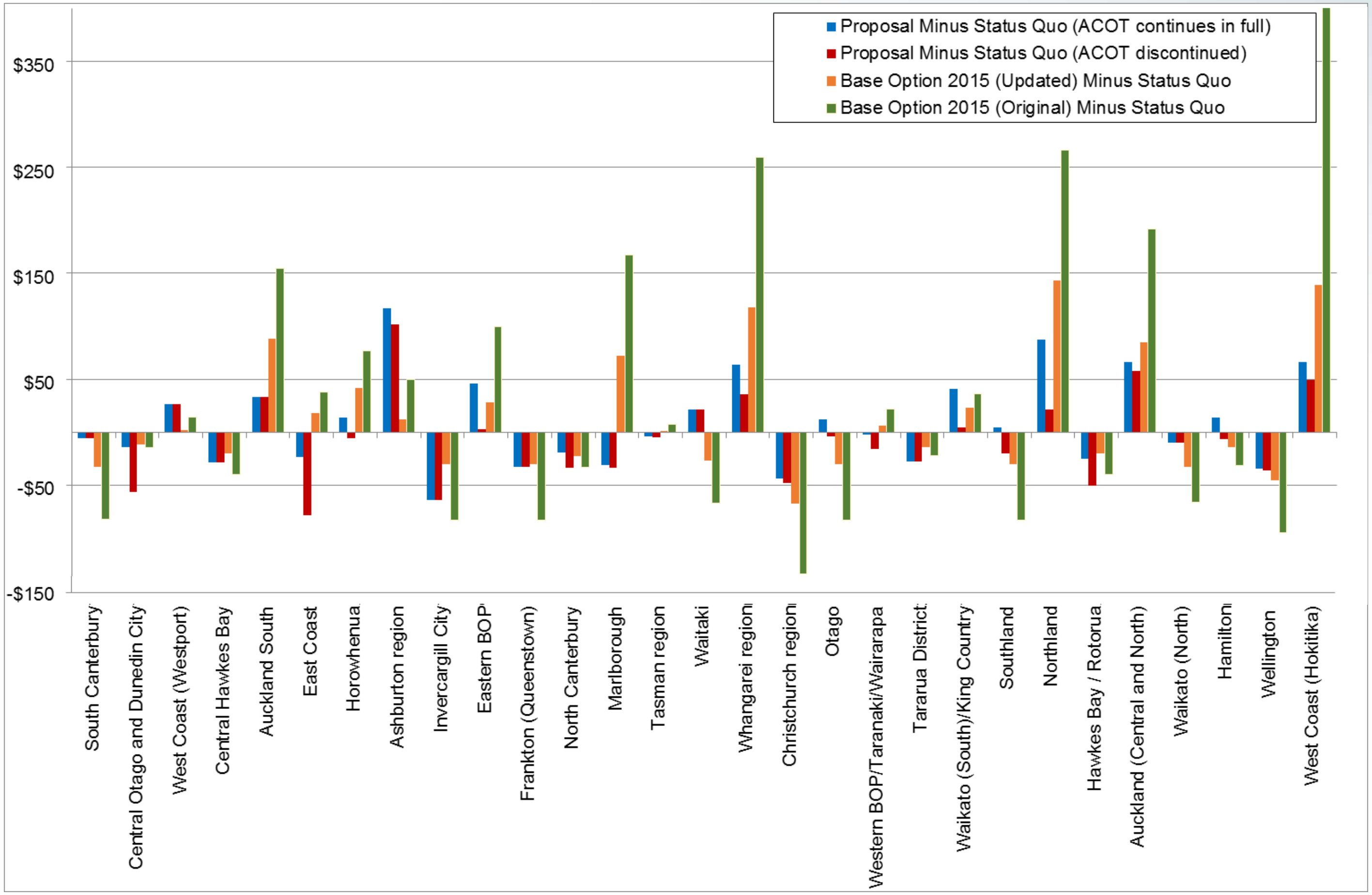
AoB charges are substantially lower than the benefits received



More moderate impact on households than in 2015 discussion

$/year impact for a typical household



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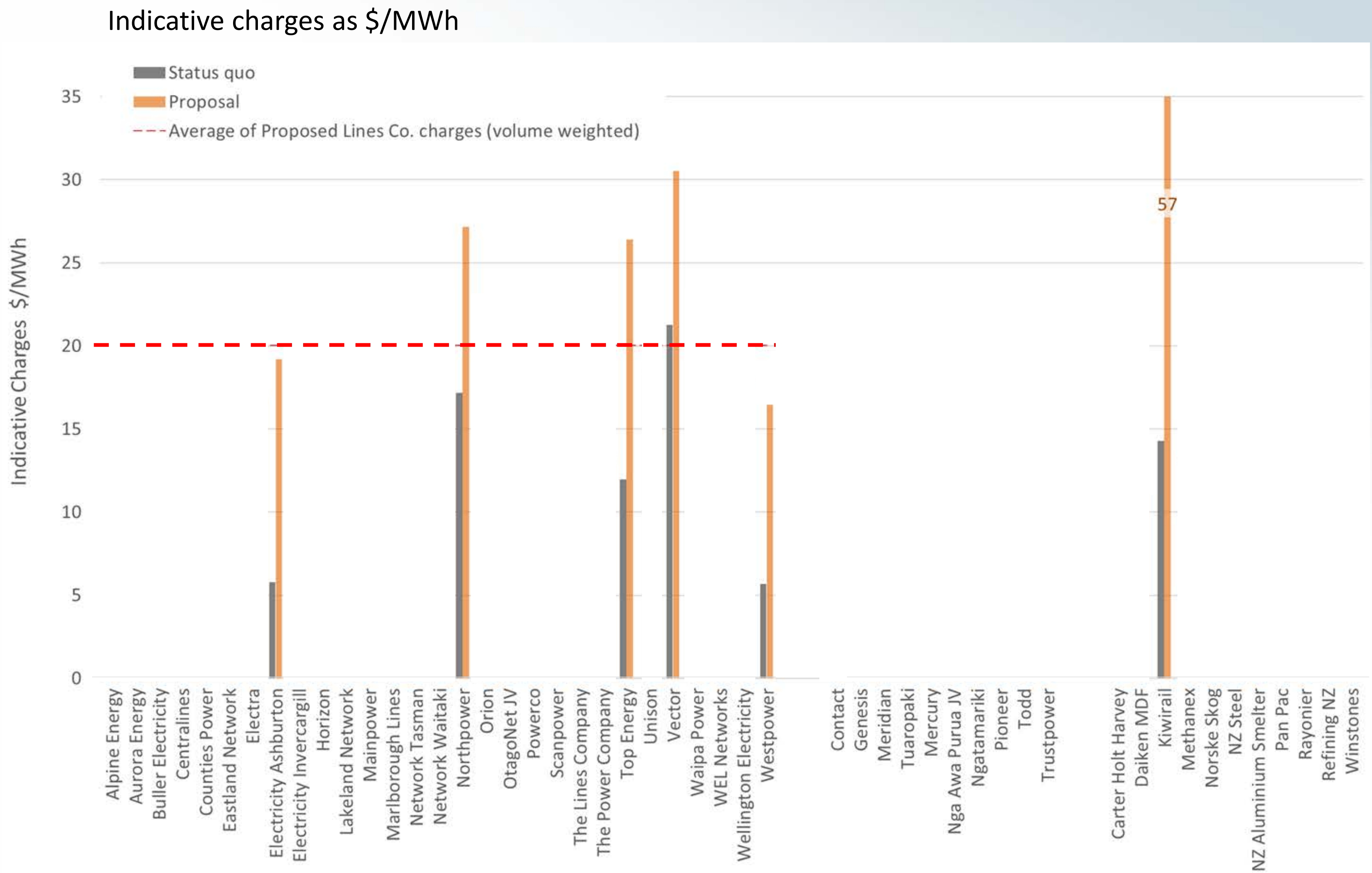
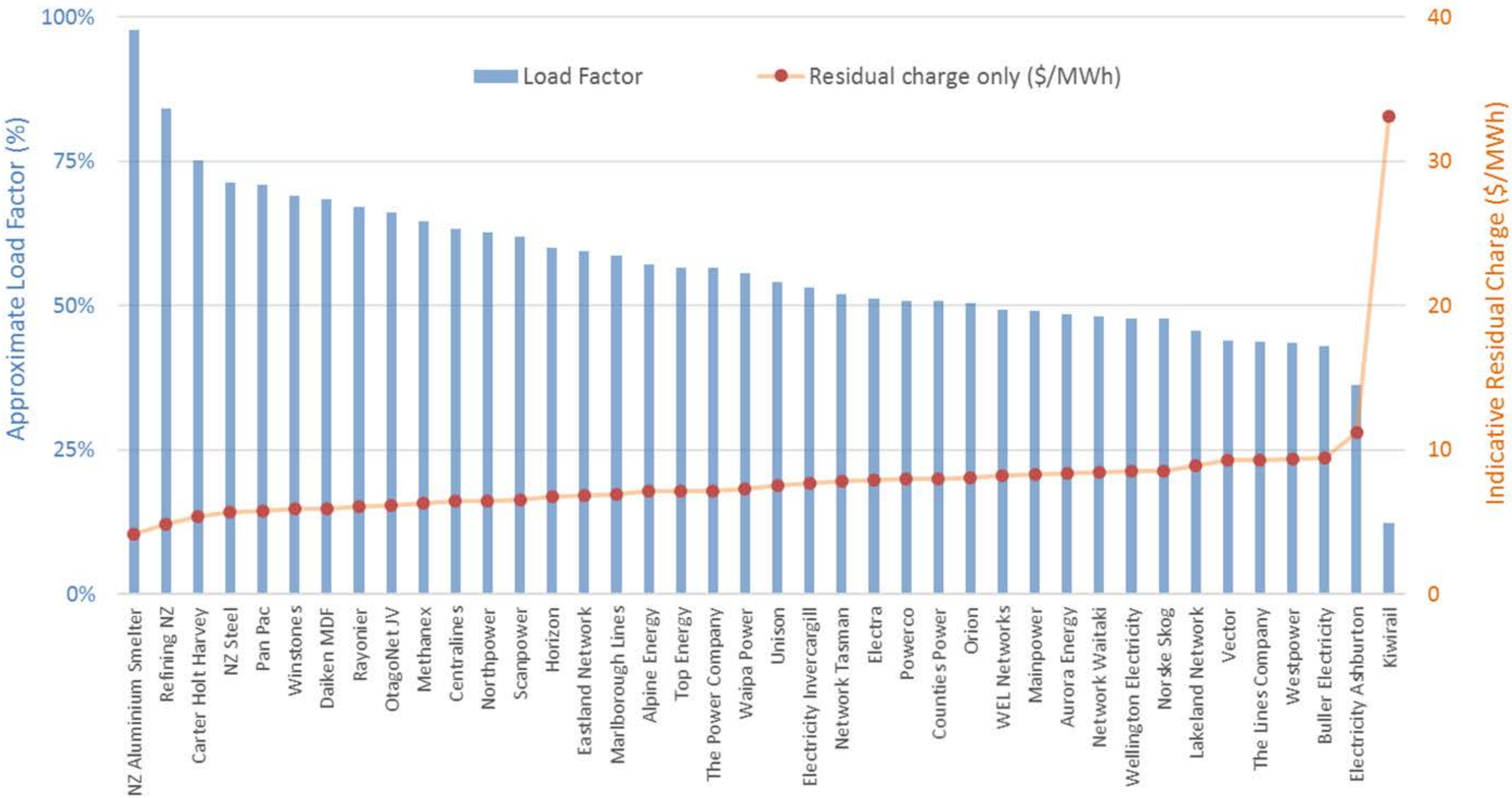
Impact of the proposal by customer group ($/MWh)



Effect of customer load factor on the residual charge



Oakley Greenwood

Cost Benefit Analysis of Transmission Pricing Options

Oakley Greenwood
14-17 June 2016

Overview of Session

- Background to OGW
- Basis for developing CBA
- Key benefits modelled
- Unquantified benefits

Background to OGW

- OGW is a consulting firm established in 2008 and led by Greg Thorpe, Lance Hoch and Jim Snow (Executive Directors) to serve the energy and water industries

- Now a team of 13 consultants and have worked for clients throughout Australia and internationally including in: NZ, Hong Kong, Singapore, Philippines, Malaysia, USA, UK, Dubai and Saudi Arabia

- Broad skill base covering Economics, Engineering, Regulatory & Governance, Project Management and Disputes

- Relevant selected experience:

  - Designed the first dynamic peak price operated by an electricity distribution business in the NEM (AusNet Services' Critical Peak Demand Tariff)

  - Advised various distribution businesses on tariff strategy and modelling over the last 3 years (e.g., Citipower | Powercor | ActewAGL | AusNet Services | United Energy | Multinet)

  - Undertook CBA of the Demand Response Mechanism for Department of Infrastructure

  - Various CBAs related to Advanced Metering Infrastructure (e.g., Jemena – CBA of continuing the rollout beyond 2013 deadline)

Basis for developing Cost-Benefit Analysis

- Test if benefits of the EA’s proposed TPM and the deeper connection option outweigh costs
- Consider benefits that arise because of the proposal
- Consider costs that arise because of the proposal
- Benefits and costs are both relative to the current TPM (including Transpower’s 2015 review)
- Benefits (in particular) can be quantitative or qualitative
- Benefits and costs over extended period are inherently difficult to quantify
  - Future conditions
  - Available data
  - Test is whether they outweigh costs

Key benefits modelled

1. Future investment in services or equipment that may otherwise be substitutes for transmission services

   - OGW's assumption is that sending more cost-reflective Tx price signals could theoretically incentivise efficient investments in alternatives to Tx in the short and long-term

2. Co-optimisation of future investment in electricity generation and transmission services

   - OGW's assumption is that both Tx options signal the costs of some future assets deeper in the grid to generators, and that this network price signal will lead new generators to co-optimise generation costs and transmission costs

3. Pricing of historical investments in the network

   - OGW's assumption is that the way in which historical investments in the network are priced will affect economic efficiency if it: (a) Distorts future consumption or investment decisions; and / or (b) Leads customers to make inefficient connection or disconnection decisions

4. More efficient quantity of Tx and generation services being demanded by the market

   - Cost-reflective Tx price signals flow through to more cost-reflective retail price signals

Summary of results for the AoB charge compared to base

Type of benefit	Value (NPV)
Future investment in services that may be substitutes for transmission services	
▪ Alternatives to transmission investment (section 8.2.2, part 1)	$1,202,796
▪ Deferrals to transmission investment (section 8.2.2, part 2)	$3,010,839
More efficient co-investment in generation and transmission services (section 8.3)	$92,748,124
More efficient quantities of services being demanded (section 8.5)	$313,601
Benefit from more efficient pricing of historical investments	
▪ Removing the HVDC injection charge based on MWh (section 8.4.2, part 3)	$13,731,094
▪ Replacement of the Regional Co-Incident Peak Demand (RCPD) charge with a charge based on physical capacity (section 8.4.2, part 1)	$89,974,887 $10,302,309
▪ Introducing a more comprehensive PDP (section 8.4.2, part 2)	
Net incremental and avoided costs (section 9.4)	$2,040,441
NET BENEFIT (COST)	**$213,324,092**

Source: OGW

Unquantified benefits

- Additional scrutiny – in particular, greater incentive for customers to reveal their willingness to pay for the services provided by Transpower during the regulatory process
  - Quantifying a net improvement from increased scrutiny is difficult and our CBA has considered this matter via sensitivity analysis
- Whilst not quantified, the structure of the AoB charge is more robust than deeper connection-based charge:
  - Two-part, fixed/variable tariff – means that the customer not only sees a total price that equates to the benefits they receive, but also a cost-reflective marginal price signal
  - In comparison, the DC charge is assumed to simply allocate the full cost of an asset according to use, therefore, it does not send a truly marginal price signal
- Deeper connection charge is based on a 5-year rolling average of flows, which creates a new "effective" per MWh charge to recover the cost of sunk assets
- The deeper connection charge may, in theory, create a locational distortion

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Cost Benefit Analysis – quantified benefits

- Authority's view:
  - provides a reasonable assessment of the benefits and costs it quantifies
  - robust to sensitivity analysis
  - unquantified benefits likely to be large

Cost Benefit Analysis – unquantified benefits

- Unquantified benefits include
  - improved scrutiny of proposed transmission investment and replacement expenditure
    - those benefiting pay the full cost – others pay nothing
    - those benefiting have an incentive to engage
      - support efficient investments
      - oppose inefficient investments
  - reduced cost of unproductive disputes
  - reduced cost of uncertainty
  - potential customers not inefficiently encouraged or discouraged from entering the market
    - eg, incentive for entry currently inefficiently high where total charges less than incremental costs
  - benefits extend beyond the 20 year period modelled
- Authority view is that these unquantified benefits are large

Next steps for the TPM review (and also review of DGPPs)

Milestone/Action	Date
Release of TPM second issues paper and DGPPs consultation paper	17 May 2016 (for 10 week consultation period). Closes 26 July 2016
Final decisions on the TPM review and review of DGPPs, potential approval of the TPM guidelines	October 2016 – indicative
Transpower develops draft TPM in accordance with the TPM guidelines the Authority approves	October 2016 – 2017
New ACOT arrangements phased in	April 2017 – 2018
New TPM takes effect	April 2019