

# TPM issues and proposal

10 October 2012

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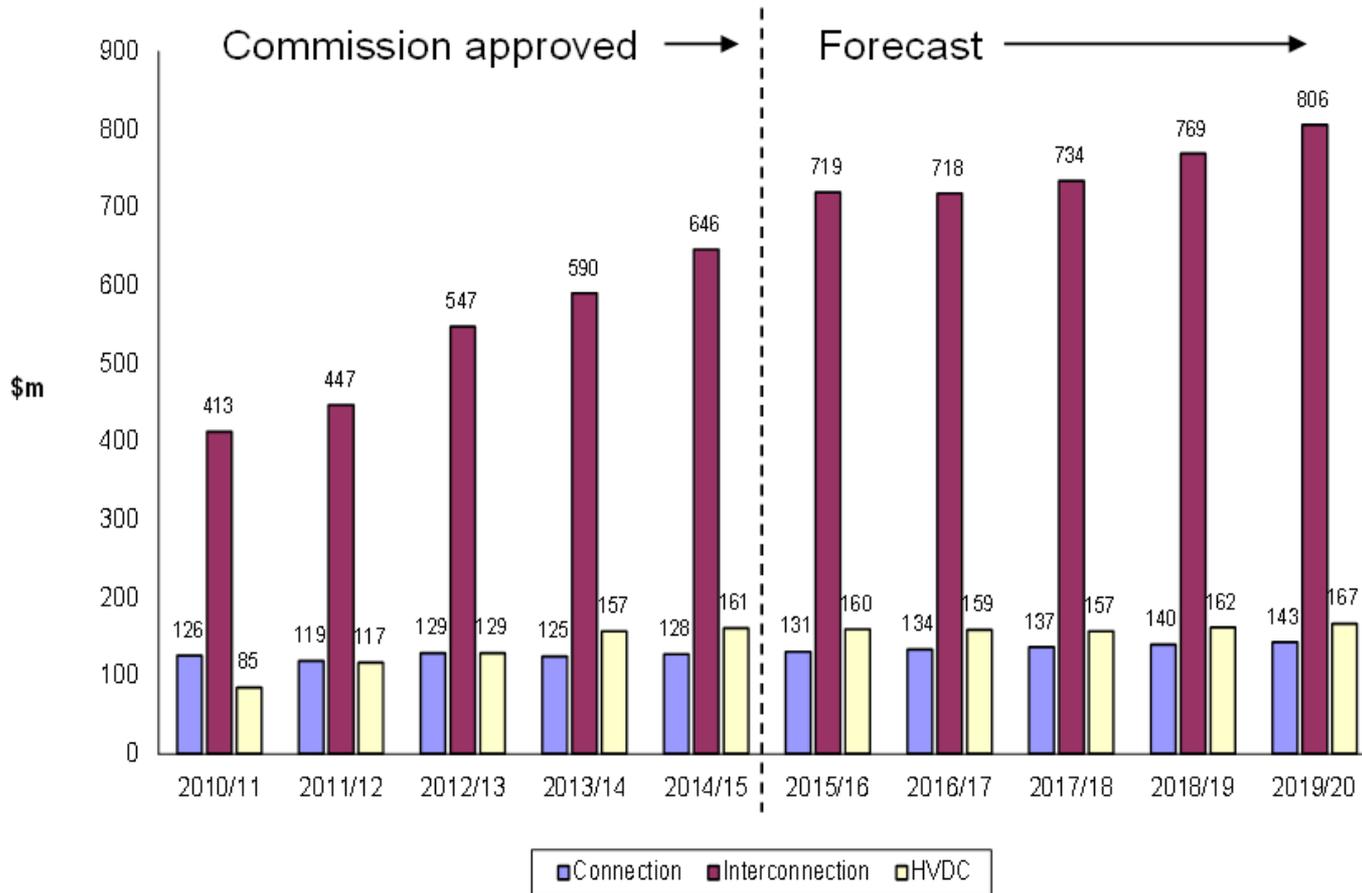
## Introduction

- ❑ The transmission pricing methodology (TPM) has been a matter of considerable contention in New Zealand and many overseas jurisdictions for many years
- ❑ We have tried hard to come up with an economically rational approach that is durable and is flexible enough to deal with NZ's conditions:
  - our wholesale market arrangements
  - the variability in our hydrology and what this does to who benefits from our transmission grid
  - our long stringy grid system with regional imbalances of generation and load
  - our regulatory regime relating to monopolies

## **Introduction** , continued

- ❑ We have built on the work of the Transmission Pricing Advisory Group (TPAG) and thank them very much
  - ❑ The proposal is relatively straightforward in that it follows and applies the decision and economic framework we set out earlier this year
  - ❑ The detailed publication includes in Chapter 6 a discussion of the more significant of the alternative options we have considered over the last few months and why we favour our proposal
  - ❑ We trust you will take the time to think about the appropriateness of what we propose for New Zealand as a whole today and into the future, and not just its current impact on your organisation and others before making submissions
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## Transmission charges to increase 79% over 10 years



Commerce  
Commission  
approves total  
revenue  
requirements

## **The Authority regulates the allocation of transmission revenue**

The current TPM has three main charges

### 1. Connection charges

- Paid by parties connecting to the transmission grid (generators, distributors and some large consumers)

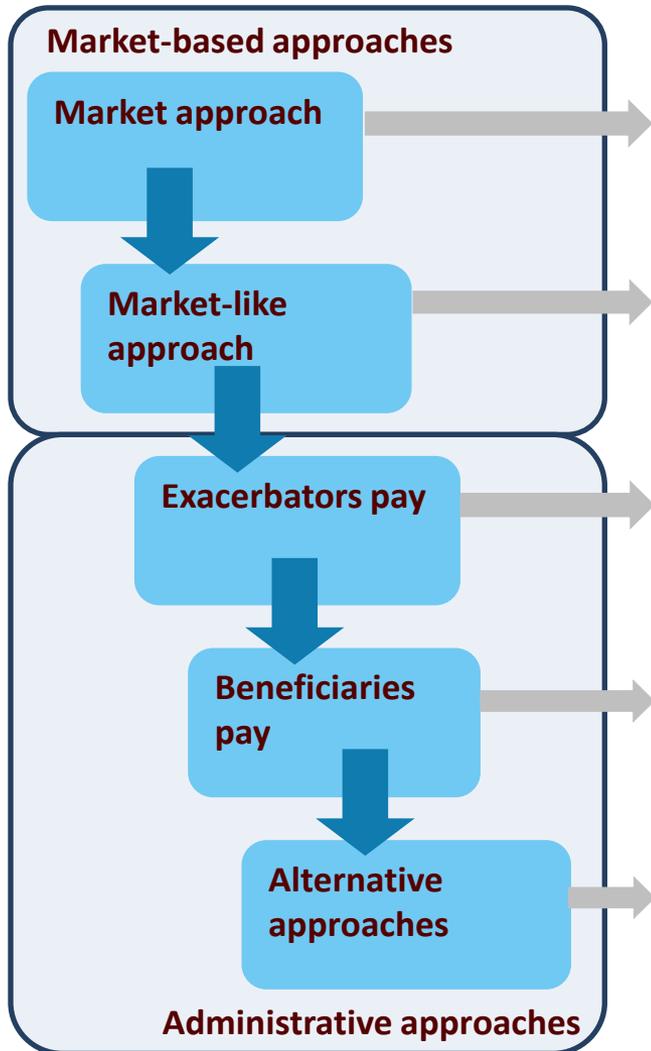
### 2. HVDC charges

- Paid by South Island (SI) generators according to their share of historical peak injection to the grid

### 3. Interconnection charges

- Largely paid by distributors and large consumers (those directly connected to the national grid)

# We consulted on the following decision framework



## Terminology

Charges established through the interaction of buyers and sellers in a workably competitive market

Charges that replicate the outcomes of a workably competitive market

Charges on parties that impose additional costs (negative externalities) on other grid users

Charges on parties that benefit from the transmission service

Charges that socialise the costs across grid users

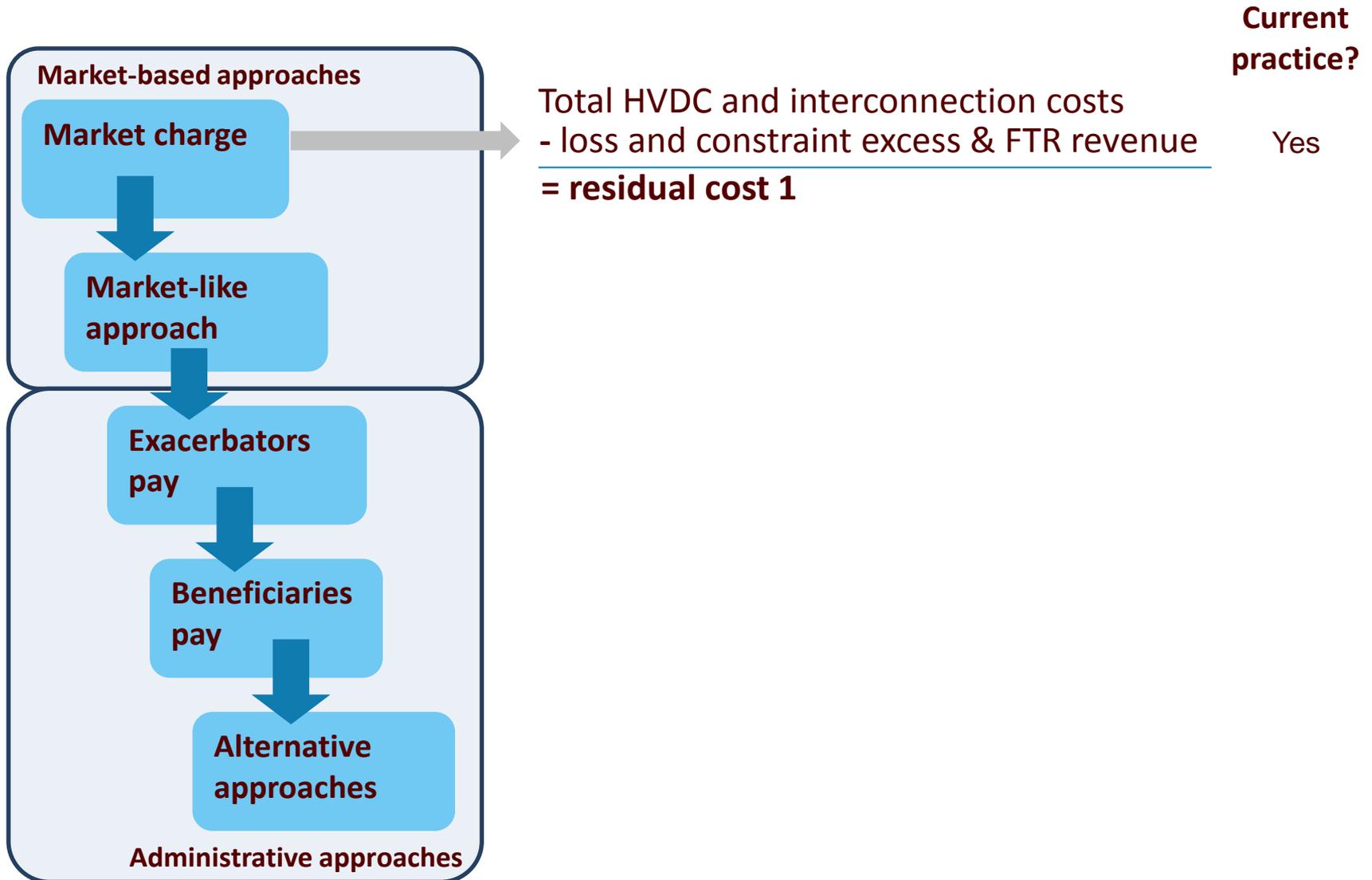
## **LCE provides a market approach to funding transmission**

- ❑ Transpower currently pays the loss and constraint excess (LCE) to transmission customers in proportion to their transmission charges
- ❑ Effectively, LCE reduces the net amount they pay to Transpower
- ❑ The Authority proposes to codify the current arrangements
  - LCE received by Transpower is to be used to fund transmission costs that correspond to the origin of the LCE
  - e.g. LCE arising on the North Auckland and Northland (NAaN) project would be used to offset the cost of the NAAAN assets
- ❑ Also proposing to codify the approach to surplus FTR auction revenue

## **LCE provides market approach to funding transmission, continued**

- ❑ In principle, LCE could fully fund the costs of transmission assets
    - This would occur if grid investments exhibited constant returns to scale (CRS)
  
  - ❑ But in practice, a large funding deficit (or residual) occurs because grid investments
    - Often have large economies of scale
    - Or are made earlier than is justified on economic grounds
  
  - ❑ Need to recover this deficit through other charges
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# Overview of proposed HVDC and interconnection charges



## Network reactive support (NRS) services

- The need to invest in **static reactive support** equipment is the result of an externality
  - Arises because parties are using power in a manner that results in a poor power factor for other transmission users
  
- Propose to address this by applying **exacerbators-pay** charge to recover the costs of static reactive support services
  - TPM to include a kvar charge based on the aggregate kvar draw of off-take transmission customers, at times of regional coincident peak demand, in areas of the grid where investment in static reactive support is likely to be required
  - Set the kvar charge at LRMC of grid-connected static reactive support investment

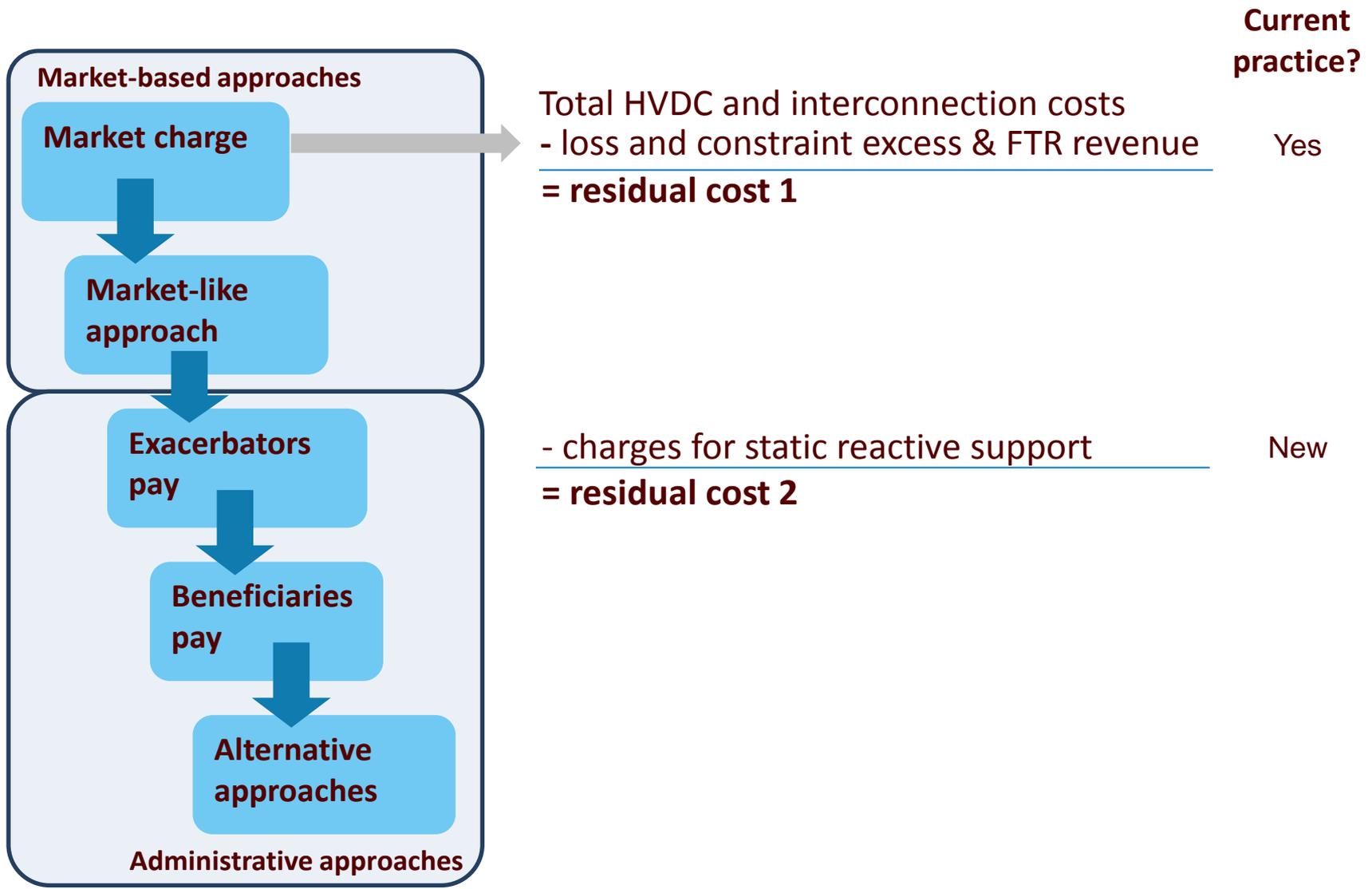
## **Network reactive support (NRS) services, continued**

- ❑ Also proposing to amend the Connection Code to set a minimum power factor of 0.95 lagging for all regions
- ❑ The exacerbators-pay charge for static reactive support provides parties with incentives to
  - Draw reactive power only when and where this is efficient
  - Or to invest in equipment to manage their reactive power use

## **Network reactive support (NRS) services, continued**

- ❑ Dynamic reactive support is needed to deal with voltage instability caused by third parties
  - E.g. a helicopter flying into power lines
  - This is an externality but its not practicable to recover charges through an exacerbators-pays charge
  
- ❑ Dynamic reactive support enhances power transfer by reducing losses
  - The Authority therefore proposes to recover the costs of dynamic reactive support on the same basis as for HVDC and interconnection

# Overview of proposed HVDC and interconnection charges



## **Polarised views on who benefits from HVDC and interconnection**

### **❑ South Island (SI) generators claim**

- They're not the only beneficiaries of the HVDC
- And they don't benefit at all from the new pole 3 for the HVDC
- Other parties, particularly consumers, claim the opposite case

### **❑ Some consumers also claim**

- They don't benefit from investments in the North Island
- Or they don't benefit from investments to transmit power to outlying regions

## **Our proposal: don't take a fixed view on who benefits**

- Rather, the Authority's proposal is to use the Scheduling, Pricing and Dispatch (SPD) model to identify the beneficiaries of recent and future grid investments
  - The SPD model is used to set prices and quantities in the market now, worth about \$4b per year
  - Using it to estimate private benefits requires additional computations, but doing that is feasible now
  - The Authority has done simulations on historical market data to check it's feasible
  
- The proposal is to apply “the SPD method” to selected grid investments
  - And allocate the cost of each investment to beneficiaries in proportion to their share of private benefits (capped at their level of private benefit)

## Overview of the SPD method (e.g. for pole 3 of the HVDC)

- Step 1: Calculate consumer and producer surpluses arising from market prices and quantities used to settle the spot market
  - This SPD solve contains all available assets including pole 3
  
- Step 2: Re-run SPD without pole 3 and calculate consumer and producer surpluses based on simulated market prices and quantities
  - Private benefit of pole 3 to a consumer = its consumer surplus in step 1 minus its consumer surplus in step 2 (provided this difference is positive)
  - Same approach for generators but calculation is of producer surplus
  - Charge the half-hourly cost of pole 3 in proportion to parties' share of total half-hourly private benefits
  - Charge is capped at lesser of half-hourly private benefits or asset costs

## Application of the SPD charge

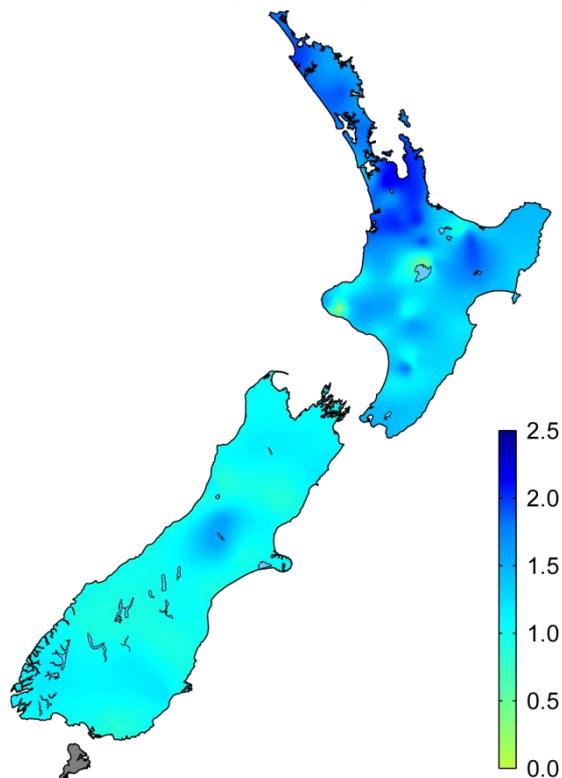
- The proposal is to apply the SPD charge to any assets added to Transpower's regulated asset base with a cost of more than \$2m (at the time the assets are added) after 28 May 2004
  - 28 May 2004 was the date when Part F of the Electricity Governance Rules 2003 came into force
  - A threshold of \$2 million will capture transmission investments from which parties participating in the wholesale market benefit, including connection parties - effectively an automatic “but for” approach to determining connection charges
  
- The SPD charge will be levied on those who benefit from access to the grid and wholesale market: generators, direct connects, retailers and distributors (to the extent they provide interruptible load or offer to wholesale market)

## Private benefit rates for load from selected grid investments

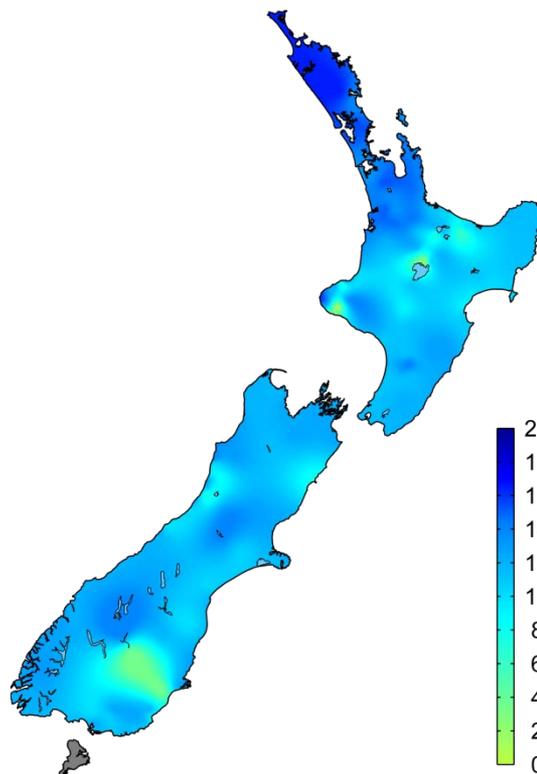
Heat maps showing private benefits in \$/MWh for period 1 July 2010 – 30 June 2012

(Note: these are benefit rates, not total benefits and not charges. Charges are to be determined using annualised cost of relevant assets)

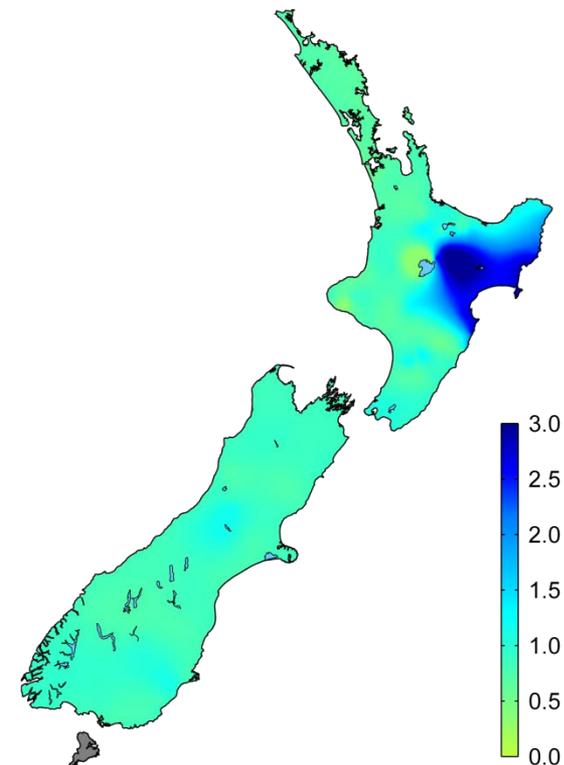
### North Island grid upgrade



### HVDC Pole 3



### Wairakei ring



## Proportion of private benefit by region for retail load

(excluding 5 major direct connect customers)

Transmission region	NIGUP	Pole 3	Wairakei Ring
Auckland	25.8%	16.0%	14.0%
Bay of Plenty	2.1%	3.5%	3.1%
Canterbury	3.3%	5.5%	3.6%
Central	2.5%	3.3%	2.4%
Hawkes Bay	1.4%	2.4%	1.5%
Nelson/Marlborough	0.9%	1.6%	1.0%
North Isthmus	15.5%	10.2%	8.7%
Otago/Southland	2.1%	3.7%	2.3%
South Canterbury	0.5%	0.8%	0.5%
Taranaki	1.6%	1.8%	1.3%
Waikato	10.5%	8.4%	8.1%
Wellington	4.9%	6.5%	4.9%
West Coast	0.3%	0.5%	0.3%
<b>Total</b>	<b>71.3%</b>	<b>64.1%</b>	<b>51.7%</b>
Balance from others (see next slide)	28.7%	35.9%	48.3%

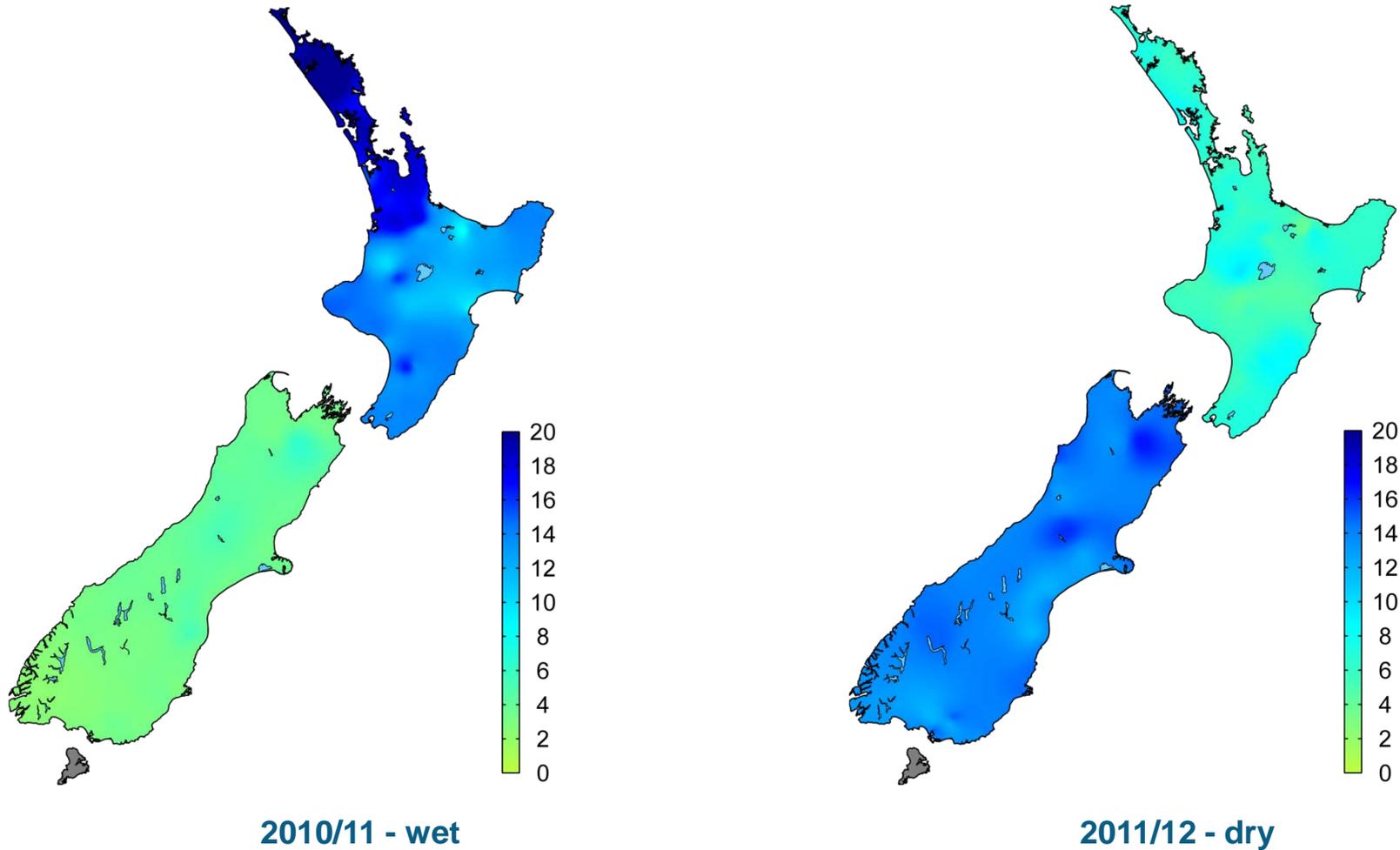
## Proportion of private benefit for generators and large load

(note: the figures for generators relate to their generation activity, not their retail activity)

<b>Generator</b>	<b>NIGUP</b>	<b>Pole 3</b>	<b>Wairakei Ring</b>
Contact Energy	3.7%	6.2%	12.3%
Genesis	3.5%	4.2%	8.8%
Meridian	1.9%	9.4%	4.1%
Mighty River Power	6.5%	2.7%	11.0%
TrustPower	1.7%	1.3%	1.9%
Todd Energy	0.4%	0.2%	0.4%
Other Generators	2.8%	0.8%	1.5%
<b>Large Load</b>			
New Zealand Steel	3.5%	2.4%	2.1%
Norske Skog Tasman	0.7%	1.1%	1.2%
Winstone Pulp	0.3%	0.5%	0.4%
Pacific Aluminium	3.3%	6.5%	4.2%
Pan Pac	0.4%	0.6%	0.5%
<b>Total</b>	<b>28.7%</b>	<b>35.9%</b>	<b>48.3%</b>

# Benefits of Pole 3 change with hydrology

Heat maps showing private benefits from Pole 3 in \$/MWh



## **This approach is flexible and durable**

### **□ Flexibility**

- We are proposing to use the SPD model to calculate private benefits every half-hour: hence it will be very dynamic and flexible
- Changes in generation and demand patterns across the grid (eg. changes with Norske Skog, Pacific Aluminium) will immediately alter private benefits and the distribution of transmission charges

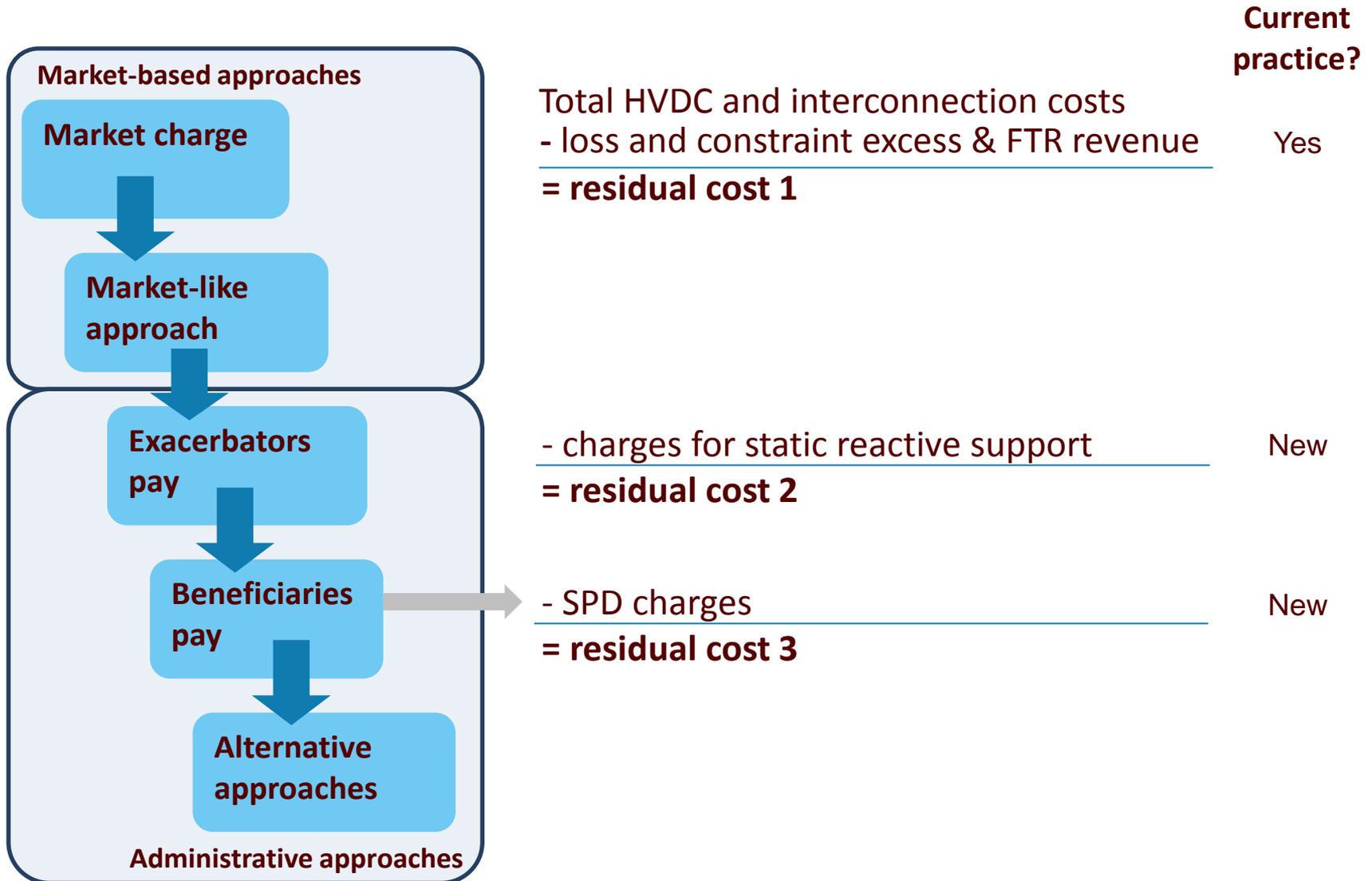
### **□ Durability**

- HVDC and interconnection assets are shared assets – it's very difficult to set charges reflecting the full costs a grid user imposes on the grid
- The SPD method should be durable as charges will be explicitly linked to benefits actually accruing to parties on a half-hourly basis

## Although variable, SPD charges may reduce overall risk

- ❑ Increasing international focus on beneficiaries-pay approach to transmission charges (eg. New York and Argentina)
- ❑ The flexibility of the SPD approach means that parties won't know for sure their future SPD charges
  - But this is the same for spot market prices and revenues, which are 5 to 10 times larger than SPD charges
  - Parties will invest in systems to estimate their future charges
- ❑ In reality the SPD charge may reduce profit volatility
  - High SPD charges come from high private benefits (= high profits) and vice versa

# Overview of proposed HVDC and interconnection charges



## **A residual charge is needed to ensure full revenue recovery**

- ❑ Residual charge levied on both demand (using RCPD) and generators (RCPI)
    - Costs split 50/50 between load and generation
  
  - ❑ Designed to encourage efficient avoidance of peak regional use of the grid
  
  - ❑ Transpower would determine
    - The optimal regions for applying these charges
    - The number of regional coincident peaks in each region to determine the charge that would apply
    - The number of peaks should reflect what is necessary to encourage efficient avoidance of peak use of transmission in each region
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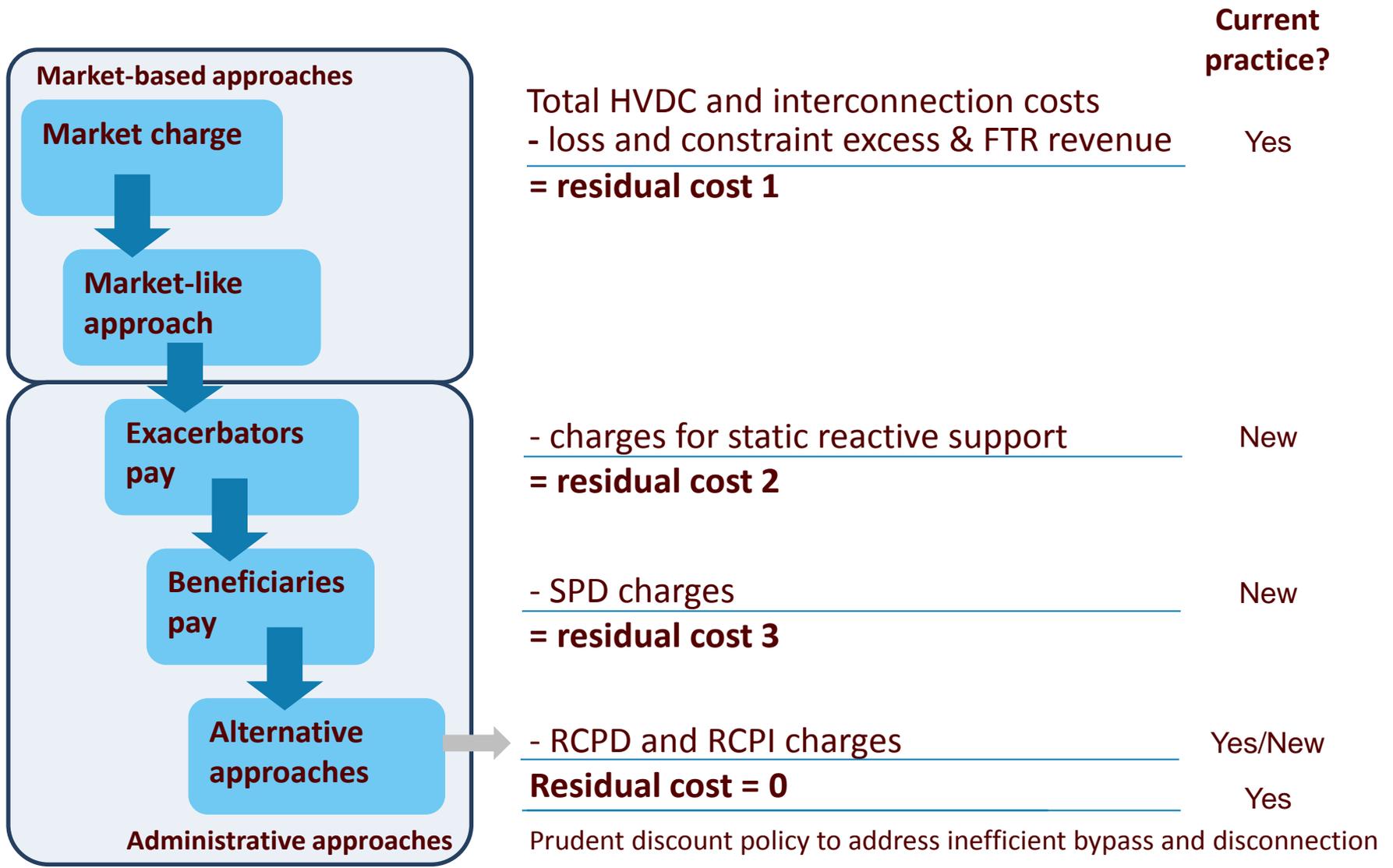
## Distributors could opt-out of this charge

- ❑ The residual charge would be applied to generators, direct-connect customers and distributors (or retailers)
- ❑ Propose to give distributors the ability to opt out of the residual charge
  - Retailers operating on affected networks would pay the residual charge
  - Distributors' ability to opt out subject to consulting with retailers on their network
- ❑ But distributors would still incur any SPD charge arising from offering to or purchasing from the wholesale electricity market (eg. for interruptible load)

## **Proposing to refine the prudent discount policy**

- Proposing to extend the prudent discount policy
  - To cover inefficient disconnection from the grid – this is because transmission costs rising 79% over next 10 years
  - To cover the life of the bypass or disconnected asset (not just 15 years)

# Overview of proposed HVDC and interconnection charges



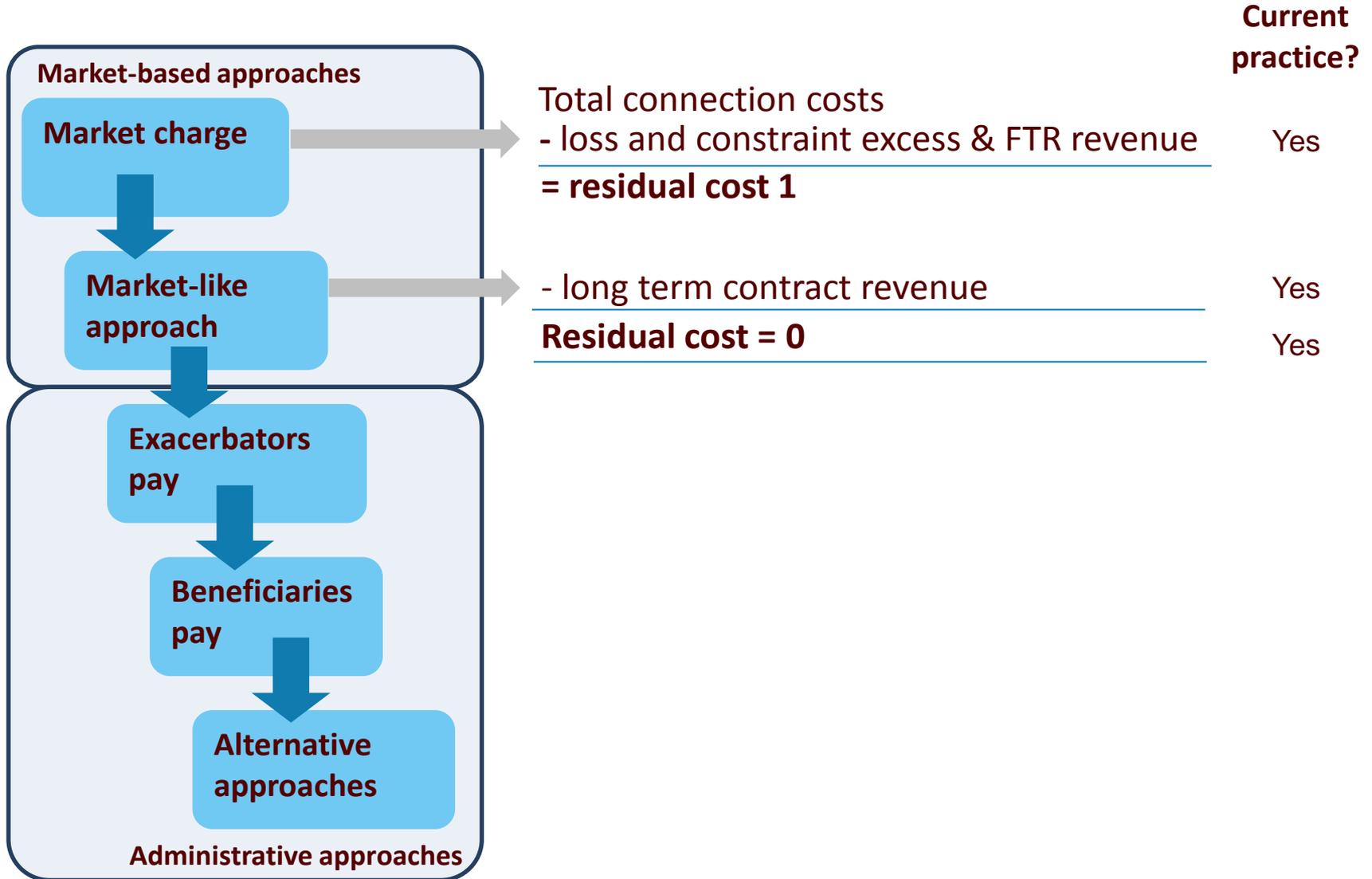
## Connection charges

- ❑ We are proposing only minor refinements to connection charges
  - The current connection charge regime is a market-based charge, promotes efficiency, and is widely supported
  - Will allow surplus loss and constraint excess and FTR revenue to offset connection charges
  
- ❑ Minor problem with current connection charge
  - Connecting parties have inefficient incentives to shift some connection costs into the interconnection charge
  - Reflects minor drafting deficiencies (loopholes) in the current TPM

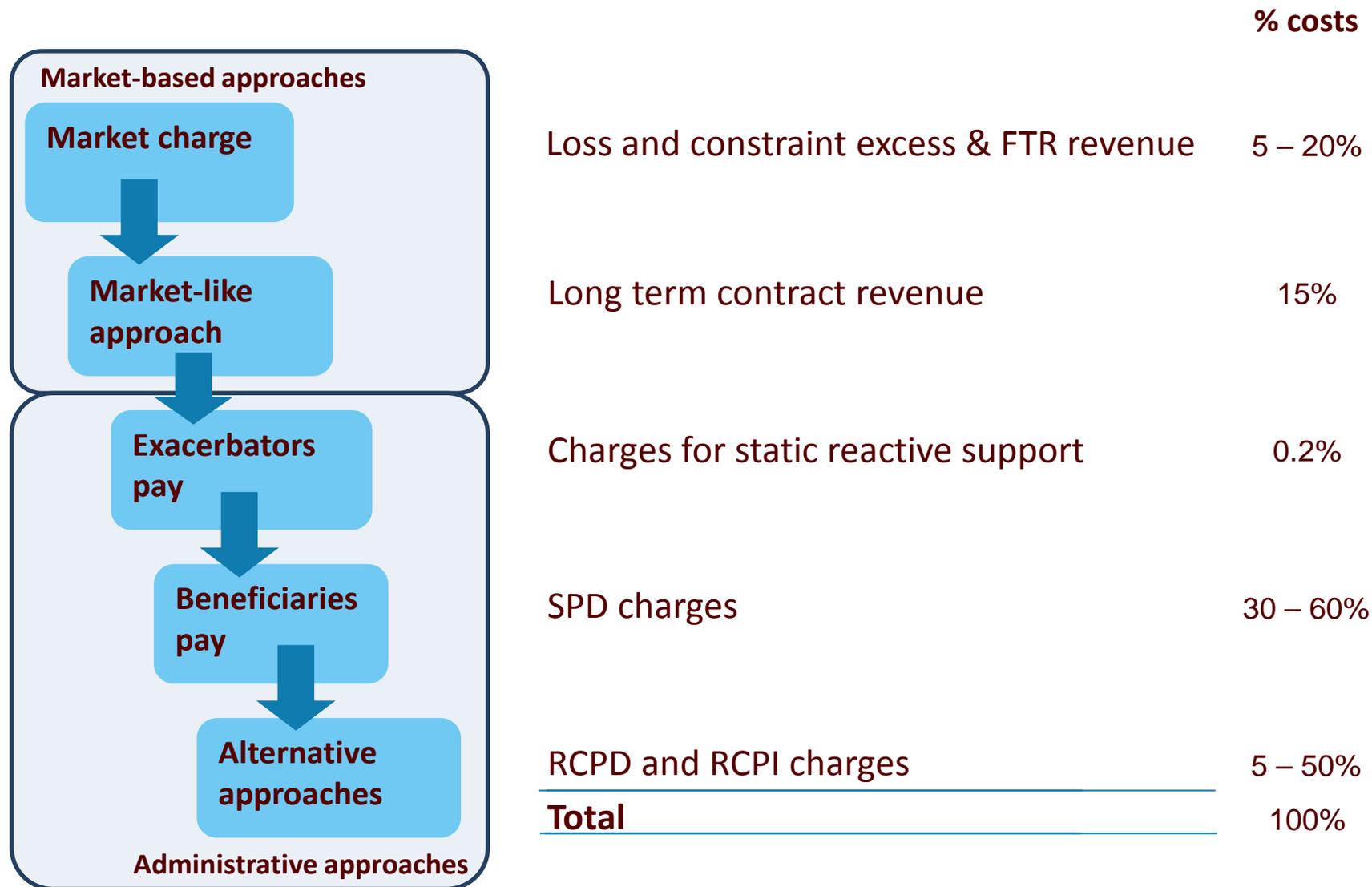
## Connection charges

- Proposing to limit the shifting of connection costs by
  - Amending the TPM to require that current connection assets be treated as connection assets until replaced or decommissioned
  - Amending the TPM to require that replacement assets are valued for charging purposes at the actual replacement project cost, and
  - Amending the Benchmark Agreement to include a mechanism to refer to the Authority disputes between Transpower and a connecting party about the level of connection charges following connection asset replacement

# Overview of proposed connection charges



# Approximate share of total regulated cost



## Comparison with Transmission Pricing Advisory Group (TPAG)

	TPAG minority view	TPAG majority view	EA proposal
Connection	Current approach	Current approach	Slight enhancement to current approach
HVDC	Current approach: charge all HVDC costs to SI generators	Transfer HVDC costs to interconnection charge (paid by distributors & consumers) over 10 year period	Clarify allocation of loss and constraint rentals/FTR revenue
Inter-connection	<p>Introduce NRS charge</p> <p>Retain RCPD charge</p> <p>Retain prudent discount</p>	<p>Introduce NRS charge</p> <p>Retain RCPD charge</p> <p>Retain prudent discount</p>	<p>Introduce NRS charge</p> <p>Introduce SPD charge</p> <p>Refine RCPD charge</p> <p>Introduce RCPI charge</p> <p>Allow distributors to opt out</p> <p>Refine prudent discount</p>

## General impacts of the Authority's proposal

### □ Large consumers

- Will in general share in minor reduction in electricity tariffs compared with the status quo
- Some will lose from refinement of RCPD and introduction of NRS charge so more efficient
- Will in general lose from shift from HVDC charge to beneficiaries-pay charge
- Will in general gain from shift from interconnection charge to beneficiaries-pay charge

## General impacts of the Authority's proposal

### □ Generators

- Generators will now pay for a portion of interconnection as well as HVDC costs, depending on their share of benefits from those assets

### □ Implications for household bill

- Overall effect will be a minor reduction in electricity tariffs relative to what they would otherwise be
- But changes in regional distribution: some regions will pay more and some less (as per the heat maps)

## Cost-benefit analysis of the Authority's proposal

Present value of economic benefits	Authority proposal (central case) (\$ million)	TPAG majority view (central case) (\$ million)
Interconnection & HVDC	\$158.2	\$36.3
Network reactive support	\$13.0	\$13.0
Connection	\$2.0	\$0
<b>Total</b>	<b>\$173.2</b>	<b>\$49.3</b>

## Briefing and consultation process

### ☐ Released today

- TPM Issues and proposal paper, Overview paper, Q & As

### ☐ Consultation

- Initial consultation closes **30 November 2012** – 7 weeks & two days
- Cross submissions closes **21 December 2012** – three weeks
- Further discussion forums in Wellington, Christchurch and Auckland
- Chair and CE meeting with chairs and chief executives of major participants
- One-on-one meetings available on request

### ☐ Aim is to have new pricing approach in place for April 2015 pricing year

# Indicative timeline as at 9 Oct 2012

