TPM options working paper

Summary of submissions (SoS)

8 October 2015

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1 Introduction

The Electricity Authority (Authority) is reviewing the guidelines that Transpower and the Authority must follow in setting the transmission pricing methodology (TPM). The TPM determines the allocation of the costs of Transpower's transmission services among its transmission customers.

On 16 June 2015, the Authority published a consultation paper titled the 'Transmission Pricing Methodology: TPM options working paper' (options working paper).

The options working paper set out three potential options for the TPM. The Authority consulted on the three options to help it determine which option would better promote the statutory objective compared with the others. The Authority advised parties that it has not formed a view, at this stage, on which should be the preferred option.

The Authority welcomed comments on whether there were alternative options, including variations on the options included in the options working paper, which should be preferred or considered further.

The paper also considers whether any potential change to the TPM should be undertaken in a way that reduces the extent to which changes result in 'winners and losers'. This could be done, for example, by applying any proposed new methodology to new assets only, capping price increases, or including transitional provisions to smooth the impact of the proposed changes on transmission charges. The Authority advised that it had not formed a view on whether potential price changes should be mitigated or, if so, how.

This paper summarises the submissions received in response to the options working paper.

The next stage in the TPM review process will be to prepare, and then consult on, the second issues paper. The second issues paper will include the Authority's TPM reform proposals and, if applicable, related draft TPM guidelines.

Who made a submission

The Authority received eighty nine (89) submissions on the options working paper, from the parties listed in Tables 1 and 2. Table 3 shows the submitters that supported another submission.

The full text of the submissions have been published on the Authority's website.[1]

[1] http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374

Table 1 Summary of submitters by type and region

By submitter type	
Other	3
Generator, retailer or rep	14
Distributor or distributor rep	18
Consumer or consumer rep	54
Total	89

By submitter location	
UNI	21
LNI	7
USI	10
LSI	30
NI	1
National	20
Total	89

Table 2 List of parties making submissions

No.	Submitter	Category of submitter	Location
1	Andrew Shelley Economic Consulting (ASEC) - LCE submission	Other	National
2	Electric Power Optimization Centre (EPOC)	Other	National
3	Transpower NZ (including Competition Economics Group (CEG) and Scientia reports)	Other	National
4	Bryan Leyland	Generator, retailer or rep	National
5	Contact Energy (Contact)	Generator, retailer or rep	National
6	Genesis Energy (Genesis)	Generator, retailer or rep	National
7	Independent Electricity Generators Association (IEGA) (including ASEC report)	Generator, retailer or rep	National
8	Kawatiri Energy	Generator, retailer or rep	USI
9	King Country Energy (KCE) (including ASEC report)	Generator, retailer or rep	LNI
10	Meridian Energy (Meridian)	Generator, retailer or rep	National
11	Mighty River Power (MRP)	Generator, retailer or rep	National

No.	Submitter	Category of submitter	Location
12	Nova Energy (Nova)	Generator, retailer or rep	National
13	NZ Energy	Generator, retailer or rep	National
14	NZ Wind Energy Association (NZWEA)	Generator, retailer or rep	National
15	Pioneer Generation (Pioneer)	Generator, retailer or rep	LSI
16	Tauhara North No 2 Trust (TN2T)	Generator, retailer or rep	LNI
17	Trustpower (including Creative Energy and Bushnell reports)	Generator, retailer or rep	National
18	Alpine Energy	Distributor or distributor rep	LSI
19	Buller Electricity	Distributor or distributor rep	USI
20	Counties Power	Distributor or distributor rep	UNI
21	Electra (including ASEC report)	Distributor or distributor rep	LNI
22	Electricity Networks Association (ENA) (representing 29 distributors)	Distributor or distributor rep	National
23	Mainpower	Distributor or distributor rep	USI
24	Marlborough Lines	Distributor or distributor rep	USI
25	Network Tasman	Distributor or distributor rep	USI
26	Northpower	Distributor or distributor rep	UNI
27	Orion	Distributor or distributor rep	USI
28	Powerco	Distributor or distributor rep	LNI
29	PowerNet (representing 3 distributors)	Distributor or distributor rep	LSI
30	Price Waterhouse Coopers (PwC) (representing 21 distributors)	Distributor or distributor rep	National
31	The Lines Company	Distributor or distributor rep	LNI
32	Top Energy	Distributor or distributor rep	UNI
33	Unison Networks	Distributor or distributor rep	LNI
34	Vector (including Compass Lexecon report)	Distributor or distributor rep	UNI
35	Westpower	Distributor or distributor rep	USI
36	A D Harwood	Consumer or consumer rep	UNI
37	Auckland Energy Consumer Trust (AECT)	Consumer or consumer rep	UNI
38	Alliance Group	Consumer or consumer rep	LSI
39	Auckland Chamber of Commerce	Consumer or consumer rep	UNI

No.	Submitter	Category of submitter	Location
40	Business NZ	Consumer or consumer rep	National
41	C G McCullough	Consumer or consumer rep	UNI
42	Carter Holt Harvey Pulp & Paper (CHH)	Consumer or consumer rep	NI
43	Community Trust of Southland	Consumer or consumer rep	LSI
44	Counties Power Consumer Trust	Consumer or consumer rep	UNI
45	Dongwha NZ	Consumer or consumer rep	LSI
46	EIS	Consumer or consumer rep	LSI
47	Employers and Manufacturers Association, Northern (EMA Northern)	Consumer or consumer rep	UNI
48	E-type Engineering	Consumer or consumer rep	LSI
49	Export Southland	Consumer or consumer rep	LSI
50	Federated Farmers of NZ, Southland (Federated Farmers Southland)	Consumer or consumer rep	LSI
51	Fonterra	Consumer or consumer rep	National
52	Grant Keymer	Consumer or consumer rep	UNI
53	HW Richardson Group	Consumer or consumer rep	LSI
54	Invercargill Licensing Trust	Consumer or consumer rep	LSI
55	JK's & Wbe	Consumer or consumer rep	LSI
56	Lewis Windows	Consumer or consumer rep	LSI
57	Market South	Consumer or consumer rep	LSI
58	McIntyre Dick and Partners	Consumer or consumer rep	LSI
59	Major Energy User's Group (MEUG) (including NZIER report)	Consumer or consumer rep	National
60	Molly Melhuish - attachment to follow	Consumer or consumer rep	National
61	Tai Tokerau Northland Economic Action Plan Advisory Group (Northland Advisory)	Consumer or consumer rep	UNI
62	NZ Steel	Consumer or consumer rep	UNI
63	NZ Council for Infrastructure Development (NZCID)	Consumer or consumer rep	National
64	Otago Chamber of Commerce	Consumer or consumer rep	LSI
65	Otago Southland Employers' Association	Consumer or consumer rep	LSI
66	Pacific Aluminium (NZAS)	Consumer or consumer rep	LSI

No.	Submitter	Category of submitter	Location
67	Preston Russell Law	Consumer or consumer rep	LSI
68	Rangitihi - R L Shepherd	Consumer or consumer rep	UNI
69	Refining NZ	Consumer or consumer rep	UNI
70	Ross G Clark	Consumer or consumer rep	UNI
71	Sarah Dowie	Consumer or consumer rep	LSI
72	South Port NZ	Consumer or consumer rep	LSI
73	Southern Institute of Technology	Consumer or consumer rep	LSI
74	Southland Chamber of Commerce	Consumer or consumer rep	LSI
75	Southland Manufacturers Trust	Consumer or consumer rep	LSI
76	Southland region	Consumer or consumer rep	LSI
77	Venture Southland	Consumer or consumer rep	LSI
78	Stabicraft Marine	Consumer or consumer rep	LSI
79	Te Houtaewa Maori Trust	Consumer or consumer rep	UNI
80	Top Energy Consumer Trust	Consumer or consumer rep	UNI
81	Vision Far North	Consumer or consumer rep	UNI
82	Waiharara Primary School Board of Trustees	Consumer or consumer rep	UNI
83	West Coast Electric Power Trust (West Coast Trust)	Consumer or consumer rep	USI
84	West Coast region	Consumer or consumer rep	USI
85	Westland Milk Products	Consumer or consumer rep	USI
86	Winston Peters	Consumer or consumer rep	UNI
87	Winstone Pulp International (WPI)	Consumer or consumer rep	LNI
88	Queenstown Chamber of Commerce	Consumer or consumer rep	LSI
89	SBS (late)	Consumer or consumer rep	LSI

Table 3 List of submitters that support other submissions

Submitter	Supported by
ENA	Electra Limited Marlborough Lines Orion New Zealand Limited The Lines Company Limited Top Energy Unison Networks Limited
IEGA	AD Howard

Submitter	Supported by
	Kawatiri Energy MainPower New Zealand NZ Energy Pioneer Generation
MEUG	Fonterra New Zealand Steel Limited Winstone Pulp International Limited
PwC	Buller Electricity Limited Electra Limited Marlborough Lines Northpower Limited
Southland region submitted by Venture Southland	Community Trust of Southland Dongwha EIS E-Type Engineering Limited Export Southland Federated Farmers Southland H. W. Richardson JK's & WBE Limited Lewis Windows Limited Market South McIntyre Dick & Partners Otago Chamber of Commerce Queenstown Chamber of Commerce SBS Bank Southland Chamber of Commerce Southern Institute of Technology Southland Manufacturers Trust Stabicraft South Port New Zealand Limited
Vector	AECT
Westpower	West Coast joint submission West Coast Electric Power Trust

2 Process

Approval of the Authority's process and/or has shown a willingness to refine its options

Alliance Group: The Authority has engaged with the industry and/or has responded to issues raised in previous consultations (p.2)

Also: Community Trust of Southland (p.1), Contact (p.1), Dongwha New Zealand (p.1), EIS (p.1), E-Type Engineering (p.2), Export Southland (p.2), Federated Farmers Southland (p.2), Genesis (p.1), HW Richardson (p.1), Invercargill Licensing Trust (p.1), JK's & Wbe (p.2), Lewis Windows (p.1), Market South (p.1) McIntyre Dick and Partners (p.1), MRP (p, 1), NZCID (p.4), Otago Chamber of Commerce (p.1), Otago Southland Employers' Association (p.1), PwC (p.3), Queenstown Chamber of Commerce (p.1), SBS (p.1), Southland Manufacturers Trust (p.1), Southland Chamber of Commerce (p.1), Southern Institute of Technology (p.2), South Port NZ (p.2), Stabicraft (p.1), Southland region (p.6), TNT2 (p.1), Venture Southland (p.6)

BusinessNZ: "The review has progressed in a methodical, thorough and thoughtful manner. In particular, we support the initiative that the Electricity Authority has shown at continuing to refine its options." (p.1)
Also: NZAS (p.21)

PowerNet: Approves of the "extensive" consultation process (p.3)

PwC: The workshops were particularly useful (p.4)
Also: PowerNet (p.3), Transpower (p.7)

KCE: "acknowledges that considerable work has gone into the development of these options which has created a great insight into the alternatives that are available" (p.1)
Also: TNT2 (p.1-2)

Genesis: "congratulate the Authority, and particularly your TPM team, in presenting the options and the implications thereof, in an honest and open manner" (p.1)

Transpower: "The OWP is a positive step…the Authority's approach of consulting both on its option and inviting alternative options is the right one" (p.1)

Information requested from the Authority was not provided
AD Harwood (p.1), Contact (p.2)

Consultation with all relevant parties is necessary
Kawatiri Energy: "the EA needs to engage with all industry participants" (p.3)
Also: NZ Energy (p.2), Westpower (p.2)

AD Harwood Limited: There has been a lack of consultation with DGs. (p.1)
Also: Kawatiri Energy (p.1)

BusinessNZ: "Authority needs to continue to be receptive to ideas from submitters that will improve the proposals" (p.1)

A lack of reliance on experts
AECT: "expert opinions supporting the concepts were not provided" (p.1)

Any TPM also needs a high level of market participant and consumer support
BusinessNZ: "if the proposals are genuinely to the long-term benefit of consumers then you would expect a high degree of consumer support" (p.2)

Cross-submissions on the options working paper would be appropriate
BusinessNZ (p.7), MRP (p.5), Transpower (p.7)

The process has been badly managed
Kawatiri Energy (p.1-2)

Great clarity around the future process is required
BusinessNZ: "Greater clarity around the future process going forward would be desirable." (p.7)

Participation in the process requires specialist expertise and resources and/or large companies are advantaged
Marlborough Lines: "Responding to the Authority's consultation on TPM, and other matters, is a significant transaction cost which advantages large companies with resources" (p.1)

Parties will prefer the option that provides them with the greatest net benefits
Marlborough Lines: "by providing details of the benefits of the proposal in its current form to certain parties secures supporters and advocates for a methodology rather than informed debates about principles and alternatives." (p.4)
Also: Ross Clark (p.1)

The Authority should engage stakeholders further
PwC: "the Authority should establish a small expert working group to help it identify the problem and develop solutions." (p.13)
Also: Vector (p.4)

Top Energy: "A broader stakeholder group could be included in the discussions at key points in the process." (p.11)

Transpower: "We recommend that, before the next proposals paper, the Authority engages directly with stakeholders to test and develop alternative options… We believe this should occur before the Authority decides whether to issue a second proposals paper or determines the content of any second proposals paper" (p.6, p.7)

The Authority has failed to used plain English
Houtaewa Maori Trust (p.2), Kawatiri Energy (p.1), Rangitihi (p.1-2), Te Ross Clark (p.2), Vision Far North (p.1-2), Waiharara Primary School (p. 2)

The Authority's review should be progressed
Fonterra (p.6)

NZAS: "…the Authority should [now] have sufficient feedback and information to form a view on how an alternative TPM can promote improved economic efficiency and develop its second Issues Paper" (p.21)
Also: MEUG (p.2)

More work is required in identifying/developing the options
ASEC for Electra/KCE (p.v), Contact (p.1), IEGA (ASEC report) (p.11), KCE (p.2), Meridian (p.2), TNT2 (p.1)

Genesis (Castalia): More work is needed on fundamental and conceptual issues and identifying options (including combinations) before minor issues are discussed and a thorough evaluation undertaken (p.9)
Also: Transpower (p.1)

WPI: Detailed design needs to be developed and should be part of the final consultation stage (p.2)

Preference against major changes
NZWEA: "major unpredictable policy changes to an infrastructure sector are acceptable. In this respect the process to date is a long way off the mark." (p.1)

Pioneer: The Authority should follow Principle 4 of the Consultation Charter (preference for small-scale trial and error options) (p.5)

The Authority should consider Castalia's analysis of the regulatory process
Genesis (Castalia): "we urge the Authority and market participants to carefully consider our analysis of regulatory process" (p.1)

Predetermination
Marlborough Lines: The Authority has predetermined the outcome of the review (p.3-4)

Mr Peters: The review shows how a Wellington regulator can manipulate to the detriment of regional electricity users (p.1)

Counties Power: The Authority has not approached the review with an open mind (p.8)

Failure to take into account previous submissions
IEGA (ASEC report): The Authority has avoided formally responding to concerns raised by any submitters (except where it cites prior submissions to provide support for its proposals) (p.v, 1)
Also: Kawatiri Energy (p.1-2)

Consultation period too short

TNT2: It is difficult to provide an in-depth response to the paper. The Authority provided further information during the consultation period, and the consultation period was unreasonably tight (p.1)

Transpower: The consultation period was too short. There was insufficient time to complete modelling (p.7, 14)

Concerns with the length of the TPM review
PwC: The long review process will create at least four more years of uncertainty, which risks impeding efficient investment (p.13)
Also: PowerNet (p.5), Top Energy (re Ngawha Power Station expansion) (p.11)

Transpower: "the review has been protracted, resource intensive and a source of uncertainty for the sector…" (p.1-3)

Also: Mr Peters (p.1), NZWEA (p.1), Pioneer, West Coast Electric Power Trust (p.3)

NZAS: "As time advances, the inefficiencies of the current TPM are extended and, with increasing market change, have become exacerbated… Pacific Aluminium urges the Authority to rapidly progress its Issues Paper and decision" (p.21)

Unison: The Authority should consider whether the costs and uncertainty of the review are not worth the potential benefit and, if so, stop the review (p.17)

Interaction of TPM review process with Commerce Commission processes
MEUG: "it is critical that [the] timetable [for publishing and consulting on the second issues paper in the first half of 2016, and making a decision on the TPM Guidelines in mid-2016,] is achieved to ensure changes to the Capex IM can then be made to supplement the TPM in order to be used for the next IPP starting in April 2020" (p.2)

MEUG: "we have a concern about the work load for all parties when consultation timeframes coincide with other work by the Commerce Commission" (eg IPP review) (p.2)

3 CBA

The Authority needs to do a robust cost-benefit analysis
Buller Electricity (p.4), BusinessNZ (p.4-5), Contact (p.2), Counties Power (p.18)
Counties Power Consumer Trust (p.2), NZAS (p.21-22)

Features of a good CBA
BusinessNZ: Calculation of net benefits in net present value terms (p.4-5)

Counties Power: Detailed and scenario-based economic analysis of status quo and benefits analysis of future changes (p.18)
Also: Counties Power Consumer Trust (p.2)

Genesis (Castalia): supported by a good set of regulatory objectives (p.5)

NZAS: Clearly articulated objectives, empirical problem definition, defensible counterfactual, cause and effect between proposed changes and efficiency gains, estimates of efficiency benefits that are testable and evidence based, adjustments for timing differences, sensitivity testing of exogenous variables other than discount rates, identification and incorporation of qualitative benefits, clear documentation (p 21-22).

Matters that should be accounted for in the CBA
Business NZ: implications for SMEs (p.4-5)

Business NZ: dynamic efficiency costs of wealth transfers, which could swamp efficiency gains (p.4-5)

Meridian: The relative certainty of different costs and benefits (p.9)

Meridian: Durability must be fully accounted for in the CBA or treated as a quantitative pre-requisite for a TPM. A TPM that is not durable can undermine investment, water down dynamic efficiency benefits, and result in TPM reviews. (p.10)

MEUG: Impact on demand-side operating behaviour (p.8)

NZ Steel: Whether signals will be strong enough or timely (p.2-3)
Also: MEUG (NZIER) (p.17)

TNT2: Transition costs and the economic impacts of price shocks (p.3)

Difficulty in assessing the proposals in a CBA
Alpine Energy: "The reliance on assumptions and perceived benefits means that transmission prices are calculated using a largely qualitative, rather than quantitative approach. Overall, the Authority has not shown that the benefits delivered by the proposed TPM justify the time and resources that will be taken up by the TPM's implementation." (p.1)

Marlborough Lines: "concerned as to the scope of the Cost Benefit analysis phase of work given the unsubstantiated assumptions made at the current stage of the process" (p.3)

Meridian: Some factors may be difficult to quantify in a CBA framework, for example durability; how the TPM components interact (p.9)

Authority has not progressed to the point where a CBA is warranted
ASEC for Electra/KCE: Any CBA at this point will be subjective and based on the benefits the Authority believes the options will deliver (p.v)

Molly Melhuish: "…What is needed is further pilot trials of both market mechanisms and technologies that enable DERs to reduce overall system costs, consumer and supplier costs alike." (p.3)

Cannot comment on implementation of options as proposal would not pass CBA
ENA: The proposals would not pass a robust CBA, and as such the ENA is not commenting on implementation issues at this stage (p.12)

4 Material change in circumstances

The Authority is best placed to determine that a material change in circumstances has occurred
NZAS: "The Authority as an independent and expert regulator is best placed to appropriately determine that a material change in circumstances has occurred in line with its assessments … consistent with its statutory purpose" (p.16)

Material change in circumstances does not restrict consideration of other problems
NZAS: The Authority is not restricted to changes that only address issues arising from the material change in circumstances (p.17)

No material change in circumstances has occurred
Trustpower (p.2)

Mr Peters: The review has been poorly justified (p.1)

Northpower "A different approach to investment planning could have resulted in a steady growth in Regulated Asset Base (RAB) and revenue requirements over a longer period. Under this scenario the associated revenue allocation would have been recovered through the existing TPM without the need for complex reform" (p.2)

Powerco: The $2bn investment was "in train" when the current TPM was approved so it cannot constitute a material change in circumstances (p.3)
Also: PwC (p.4)

Powerco: The SPD method was already running in 2007 and the recent direction to run ex-post requires less speed than ex-ante, so computing technology does not constitute a material change (p.3)
Also: PwC (p.4), Marlborough Lines (p.4)

Powerco: "the broad scheme of the regulatory framework governing approvals has not changed, so this cannot constitute a material change in circumstances." (p.3)
Also: PwC (p.4)

TNT2: Although, if a robust case was made to clearly and empirically address inefficiencies in the current TPM, TNT2 would, in principle, accept this (p.2)

A material change has occurred
PowerNet (p.2), Contact (p.1)

Alliance Group: "We agree that there has been a material change in circumstances in three ways: firstly the significant investment in the grid since 2004, secondly the advances in technology that enable easier collection of data and thirdly significant changes in the regulatory regime."

Also: Community Trust of Southland (p.1), Dongwha (p.1), E-Type Engineering (p.2), Export Southland (p.2), Federated Farmers Southland (p.2), HW Richardson (p.1), Invercargill Licensing Trust (p.1), JK's & Wbe (p.2), Lewis Windows (p.1), Market South (p.1), McIntyre Dick and Partners (p.2), NZAS (p.16), Otago Chamber of Commerce (p.1), Queenstown Chamber of Commerce (p.1), Queenstown Chamber of Commerce (p.2), SBS (p.1), South Port NZ (p.2), Southern Institute of Technology (p.2), Southland Manufacturers Trust (p.2),

Unison: "the Authority is justified in re-examining the basis for allocating transmission charges due to the significant investments that have been made which ostensibly benefit specific parties" (p.4)

Other possible material change in circumstances
Molly Melhuish: An even more material change is changes in demand trends, including the development of distributed energy resources (e.g. rooftop solar), home insulation, heat pumps, and the removal of log burners (p.1)

Molly Melhuish: "The regulatory framework has changed, with ComCom now required to approve grid investments. This dissociation of responsibility is leading to dual investment by end users in competition with Transpower and lines companies." (p.3)

5 Interpretation of the statutory objective

The Authority has exceeded its mandate/statutory objective
NZWEA (p.1)

Trustpower: By seeking to influence transmission investment decisions (p.28)

The Authority has properly defined its statutory objective
Alliance Group (p.2), Community Trust of Southland (p.1), Dongwha New Zealand (p.1), E-Type Engineering (p.1), Export Southland (p.1), Federated Farmers Southland (p.2), HW Richardson (p.1), Invercargill Licensing Trust (p.1), JK's & Wbe (p.1), Lewis Windows (p.1), Market South (p.1), McIntyre Dick and Partners (p.1), Otago Chamber of Commerce (p.1), Queenstown Chamber of Commerce (p.1), SBS (p.1), Southern Institute of Technology (p.2), Southland Manufacturers Trust (p.1), South Port NZ (p.2), Southland region (p.3), Stabicraft (p.1), Venture Southland (p. 6)

NZAS: "The Authority correctly interprets its purpose statement as requiring it to promote economic efficiency, or a total welfare standard which is supported by legislative history" (p.9-10)

MEUG (NZIER): "we see the Authority focus on efficient grid usage and investment as the right one" but there are some objectives that the Authority has missed/to which the Authority needs to attribute greater weight, for example, willingness to pay; Hogan's important concerns regarding fairness, market-central planning tensions, and the efficiency of the required revenue pool (p.12)

The objective requires transparency and objectivity
Transpower: The statutory objective requires that the distributional impacts of individual design choices are made transparent and are objectively justified (p.5)

Authority needs to directly establish how the options promote the statutory objective
Marlborough Lines: "Options and variations presented do not promote competition and improve efficiency. Aside from stating that the options would encourage engagement, there is no description of precisely how the options outlined would promote competition and improve efficiency." (p.3)
Also: Top Energy (p.1)

Meridian: The DME and Code Amendment principles are useful but the ultimate test is whether the statutory objective has been met. Meridian supports testing options against the three limbs of the statutory objective (p.9)
Also: PwC (p.5)

Assessment of competition limb
IEGA (ASEC report): "The promotion of competition should not be restricted to short-run static competition…Instead, the promotion of competition should focus on long-run competition: such competition is still between generation of all forms, but taking into account the cost of delivery infrastructure." (p.9)

EPOC: "quantifying …[competition benefits] is very difficult, as they depend on counterfactual estimates of efficiency losses from exercise of market power." (p.6)

Options do not deliver long term benefits to consumers and are not consistent with the statutory objective
Counties Power Consumer Trust (p.1), Top Energy (p.1), West Coast Electric Power Trust (p.3), Westpower (p.2)

Bryan Leyland: "what is really needed is an overview of the options from the point of view of the effect it will have on the consumer … The consumers will suffer most." (p.2)

NZCID "if the uncertainty created by this review and the precedent it sets for ongoing regulatory intervention results in increased costs to electricity providers, these costs will be passed on to consumers and may not be in their long term interest." (p.1)

Molly Melhuish "Regulation is protecting the investors at the expense of consumers. This is virtually made explicit in Section 2.2 of the Authority's Consultation Charter." (p.1)

The Treaty of Waitangi was not considered
Waiharara Primary School: No consideration was given to issues pertinent to Tangata Whenua and rights under the Treaty of Waitangi (p.1)
Also: Rangitihi (p.1), Te Houtaewa Maori Trust (p.1), Vision Far North (p.1)

The Authority has not applied the statutory objective in relation to its treatment of distributed generation
NZ Energy: "The proposed TPM changes fail on ALL accounts [of the SO, because]

- Competition: DGs provide true competition to Transmission." Imposing a policy that would make DGs uncompetitive would reduce competition. [Competition is a primary driver for any free market, (p.4)]
- Reliability: More DG increases the reliability of a power system. "A good example of this is our more isolated regions where running "islanded" is a frequent occurrence."
- Efficient Operation: "It would be a brave economist to argue that DG is in-efficient…It's not about what looks right on an Analysts spreadsheet, its more so what's actually going on out there in the field."
- Long Term benefit of consumers "DGs are a long term investment. They are therefore the perfect "partner" for the consumer" (p.2)

Equity considerations/wealth transfers are not part of the Authority's statutory objective and should not be considered

ENA: The Authority does not have an equity mandate, so should not be trying to incentivise participation in the grid investment process with a view to increasing equity. In any case, equity is subjective and the proposed allocation does not appear to be equitable (page 8).

Meridian: "The Authority should not sacrifice a better approach to transmission pricing simply because there will be winners and losers (p.12)
Also: PwC (p.4)

NZAS: "While social disadvantage is a serious issue … the Authority is not mandated to solve social policy matters unless … this promotes economic efficiency for the long-term benefit of consumers" (p.14)

Southland region: The social impact of the TPM is the Government's responsibility, not the Electricity Authority's (p.3)
Also: Preston Russell Law (p.3), Venture Southland (p.2)

Transpower (CEG): "[Since a cross-subsidy problem has not been established] the concern expressed in the Options Paper about the 'cost-reflectivity' of transmission costs appear not to be motivated solely by efficiency considerations. Rather, they seem to be based also on notions of equity… that is not to say that there is no merit in seeking to implement a more equitable allocation of charges… 'fairer' charges have the potential to be less contentious and more durable" (p.27)

Trustpower: "The Authority has put equity as its primary objective, proposing to use beneficiaries-pay approaches applied to historical investments. In our view this approach will distort behaviour, especially when applied ex-post." (p.6)

The Authority should consider wealth transfers/equity considerations, and this would be within its statutory objective

AECT: "an unfair wealth transfer from consumers to generators, particularly as an equal sharing of costs could lead to a reduction in retail prices of between 2%-3%, as set out in Compass Lexecon's paper." (p.2)
Also: Vector (CLEX report) (p.4)

Contact: "imperative that the Authority pauses and considers the impact of the proposals on customers, particularly those where the price change will be most acute" (p.1)

Genesis: Wealth transfers should be considered, as they affect the durability of options (p.4)

IEGA (ASEC report): "From an economic perspective, unjustifiable wealth transfers remove certainty for investors. This reduces incentives for investment and increases long-term costs to consumers." (p.16)

Kawatiri Energy (p.1), Marlborough Lines (p.3-4), Nova (p.1), Pioneer (p.4), Te Houtaewa Māori Trust (p.1-2)

NZ Energy: because "consumers" means every consumer in New Zealand, and many rural consumers will be faced with huge increases in charges. The Authority's role is not to redistribute wealth (p.2)

Vector: "The Authority's responsibility to ensure long-term benefits to consumers does not equate to delivering benefits to some consumers at significant cost to others." (p.2)

Vector (CLEX report): "Had users expected transmission charges to change as it is now proposed by the EA, their investment decisions would have been different." (p.8)

Waiharara Primary School: "the philosophy behind your discussion papers is based on a very narrow socio-economic model and has failed to ensure that it makes accommodation for ensuring that regional development in the remoter parts of the country is supported by reasonably priced electricity. Without a wider accommodation, remoter regions will increasingly become a burden on the state" (p.1-2)
Also: Vision Far North (p.1-2), Rangitihi (p.1-2)

Authority not required to come up with an optimal solution
NZAS: the Authority is not required to determine that an option is optimal in terms of efficiency, it is required to identify improvements on the current arrangements and implement those improvements if there is a net efficiency benefit (p.11)

6 Decision-making and economic framework (DME)

The DME is not fit for purpose
ENA, Orion (p.5), Powerco (p.4), PwC (p.5), Trustpower (p.2)

Multiple options on same DME indicates that the DME is not helpful
Trustpower (Vince Hawkesworth letter): "the Authority has put forward a number of options for consultation using the same economic and decision-making framework. Each of these options, not to mention design choices within each of the options, has quite a different incidence of potential charges. This raises serious questions about the extent to which the decision-making framework provides any insight as to the true beneficiaries of an investment" (p.2)

DME does not provide a way to assess the relative merit of options
Genesis (Castalia) (p.5), Trustpower (p.2)

Applying the DME leads to complex overlapping components without assessing how they could best work together
Genesis (Castalia) (p. 5), Trustpower (p.20)

The DME does not produce simple options
Genesis (Castalia): The DME does not produce consistent, varied, and simple options (p.10)

Transpower: The DME precludes sensible options from consideration (p.4)

The deeper connection charge appears not to be market-like on the DME
Genesis (Castalia) (p.9), MEUG (NZIER) (p.5), Trustpower (p.9)

Orion: This indicates that the DME is not useful (p.5)

Options should not be assessed based on DME
ENA: the Authority needs to assess options on a CBA, not the DME (p.7)
Also: PwC (p.5)

Genesis (Castalia): The Authority needs a way to link the different charging options to the CBA (p.iii)

Transpower: DME should be viewed as guidance, rather than a rigid hierarchy (p.4)
Also: Meridian (p.4)

Meridian: Ultimately, the Authority's decision should be based on which TPM option best meets its statutory objective (p.4)

Suggested revised hierarchies to the DME
Trustpower: A revised hierarchy to the DME

- "Free market (applies to competitive and not monopoly services);
- Regulated market…
- Exacerbator pays…
- Alternative, administrative residual charges based on Ramsey pricing principles" (p.10)

Genesis (Castalia): "We see three stages in setting transmission prices:

- Allocating assets into groups or "pools"
- Designing charges to recover the costs of different asset pools in ways that achieve particular objectives
- Determining the mechanics of how charges will be set." (p.10)

…In our view, the options working paper only focuses on the stage of designing charges… we consider that the other two stages are equally important" (p.11)

The DME correctly reflects the Authority's statutory objective
NZAS (p.20)

Misuse of DME
ENA: The Authority is misusing the DME to give unwarranted preference to some options (p.7)

7 The Authority's evaluation and analysis of options

The options are all very similar

Genesis: "The options…are not sufficiently diverse for parties to assess the relative merits of each element." (p.1)

Genesis (Castalia): Varied options are important at this stage because focus should be on identifying the trade-offs being made in the design of transmission prices (p.10)

Marlborough Lines: "The process is flawed by considering such a narrow range of potential solutions." (p.3)

PwC: "the options presented are essentially three very similar methodologies which deliver similar [charge] outcomes" (p.4)
Also: West Coast Electric Power Trust (p.3), West Coast joint submission (p.3)

Insufficient rigour in analysis
ENA: The analysis is "not at a level of rigour required in light of the magnitude of the values involved and in many cases is based on subjective views rather than objective analysis." (p.6)

ENA: The Authority has dismissed RCPD and standalone LRMC with insufficient analysis (p.11-12). The Authority has provided insufficient analysis in relation to LCE, so ENA is unable to comment on the LCE proposals. (p.6)

ENA: The ENA would ideally prefer to engage constructively with alternative proposals instead of criticising, but does not have the resources. It is the Authority's responsibility to develop and objectively test a broad range of proposals (p.13)

MEUG (NZIER): The overall efficiency of the base case is difficult to determine because "none of the mechanisms make it easy to identify whether they meet the economic criteria - the Authority has made trade-offs, some of which are hard to understand" (p.14-15)

Orion: the problem definition is short on empirical information (p.1)

Transpower (CEG): "Terms such ‘beneficiary’, ‘market-like’ … have never been clearly defined and they continue to be applied inconsistently." (p.38)

Vector: Pacific Steel has been included in the paper as a major industrial direct connect to the grid but is in fact a direct connect to Vector’s distribution network. This error calls into question the level of scrutiny the Authority has applied to the detail of its proposal (p.4)

Aspects of the Authority's analysis that are not clear
ENA: It is unclear how the counterfactual has been treated. For example, are costs additional or total costs? (p.6)

NZ Steel: "Direct pass-through of Transpower charges is a key requirement of contractual arrangements we have with EDBs…The options paper is silent as to how calculations can be applied at individual nodes/GXPs. This detail is critical..." (p.2)

Trustpower: It is not clear how the Authority has incorporated practical considerations, transaction costs, consistency and certainty into the review (i.e. the considerations that were previously removed from the Code) (p.8)

Evaluation of AoB charge
WPI: We suggest that the use of an Area of Benefit charge, which covers substantially the same assets as the current HVDC charges should be evaluated and justified on its own merits, and separately from HVAC asset related costs…" (p.2)

8 Alternative objectives, approaches and frameworks

Alternative frameworks for analysis
Genesis (Castalia) "There are four critical steps in this regulatory process:

- Describing the status quo and defining current problems
- Developing objectives that any options for change should achieve
- Identifying plausible options to use in the TPM guidelines
- Assessing the ability of options to meet the objectives and generate net benefits." (p.3)

Genesis (Castalia): "Given their use in evaluating options, we expect the Authority will articulate its review objectives in its second issues and proposal paper. However, there is sufficient information available now to identify what the Authority's objectives should be… Without having explicit objectives, the options paper leaves the reader with a sense that options may resolve identified problems with the current TPM, but without any perspective on whether options will result in better outcomes overall." (p.3-5)

Pioneer: [from California Utilities Commission] "Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardises data and methodologies to address locational benefits and costs of distributed resources" (p.5)

Objectives for a TPM
Buller: The Authority should consider

- "the flow-on effect of its proposed TPM on distribution pricing"
    - E.g. "Locational cost reflectivity for BEL's sparsely populated network region may deliver significant price shocks to rural consumers—but without delivering any efficiency benefits"
- Does cost reflectivity require deep connection charges and/or LRMC pricing
    - To what extent has the EA considered and/or analysed the benefits, and is it available in a readily accessible manner p.3
- The TPM must recognise circumstances where transmission customers would not agree to pay for the existing service potential of deep connection assets if negotiations were taking place today
    - Most of the current transmission infrastructure was built without regard to market-like principles and/or economically efficient outcomes
    - It is fundamental that any retrofitted deep connection charge requires optimisation as well as utilisation adjustments

- Investments in long life transmission infrastructure will be inefficient unless the industry regulators provide a clear statement of who assumes the primary risks and rewards of asset ownership under the proposed TPM
    - It is not clear whether the negotiated, competitive outcomes the EA is seeking under the proposed TPM will easily fit with the Commerce Commission's approach
- The EA should give consideration to reducing the more extreme impacts of the proposed TPM—in particular through transitional mechanisms (e.g. a glide path), and a broader HHI range for phasing in the deeper connection charge" (p.2-3)

Business NZ: "the goals (or objectives) that the Electricity Authority should be striving to achieve are, in BusinessNZ's view:

1. to optimise the locational choices for new connection assets. Achieve this by:
    a. relying wherever possible on private contracting with directly affected parties for the provision of, and payment for, new connection assets; and
    b. where not possible, allocate the costs of connection assets as fixed charges amongst the connected parties.
2. the goal for all other costs—for interconnection assets and the HVDC—is to allocate the sunk costs in such a way as to:
    a. recover the cost of the asset in a non-distortionary way, say based on capacities, not generation; and
    b. efficiently trade-off the fairness of cost-sharing rules and any perverse incentives the rules may create.

We are pleased to see that some of these ideas have been captured by the Electricity Authority." (p.2-3)

EPOC: "transmission system provides several benefits for electricity consumers. In any trading period the presence of transmission provides

- System reliability [currently treated as a public good];
- Market competition [difficult to quantify];
- Short-run efficient dispatch [The beneficiaries of this dispatch are consumers who receive power at lower prices than those asked by local generating plant];
- An option to use cheaper power [This option has a value that should be priced in the market].

These benefits are quite different in form. Pricing mechanisms to pay for each of these benefits must therefore be different. It is not clear how to combine these to produce an enduring, efficient pricing, mechanism." (p.4)

Transpower: "Our preferred outcome for this review is a decision that yields a workable TPM. This means that it finds general acceptance among the main stakeholder groups and encourages our customers to sensibly manage their loads (to help us defer investment) and to sensibly engage in the grid investment process." (p.1)

Genesis (Castalia) provided a list of objectives as follows: efficient transmission investment, efficient generation investment, efficient load investment, efficient operation of the wholesale electricity market, efficient operation of the retail electricity market, sustainability/durability. This was broken down into more specific objectives, and a list of influences on each of the outcomes (p.7-8)

Genesis (Castalia): "Our initial evaluation against [the criteria specified by Castalia] suggests that DCC performs worse against the TPM objectives than other beneficiaries pay charges (AoB, SPD), while AoB outperforms the LRMC charge… our evaluation also shows that the approach to application matters as much as the charging option chosen." (p.iii)

MEUG (NZIER): "There is reasonable agreement in the literature regarding what matters when developing transmission pricing arrangements... Brunekreeft et al suggest that transmission charges should encourage:

- Efficient short run use of the grid
- Efficient investment in expanding the grid
- Efficient signals to guide investment decisions by generation and load
- Fairness and political feasibility
- Cost recovery" (p.4)

MEUG (NZIER): "In our view we believe objectives for the TPM could be: efficiency…recover fixed costs…transparent… Non-discriminatory… These 'pricing' objectives are however difficult to relate to the transmission grid in a practical manner and as discussed involve trade-offs regarding their relative importance that will change as grid and grid users circumstances alter over time… If we start with the proposition that the efficiency objectives of the grid are optimised from the existence of (marginal cost based) nodal pricing we then turn to the practicalities of applying these objectives to grid charges to:…

1. recover investment costs - which suggests that overall charges should be equal to average costs
2. provide incentives for investment - suggests that charges should be de-averaged by location and based on long run marginal costs

We see an obvious tension between these two approaches to transmission pricing that the Authority TPM mechanisms need to overcome in a practical sense." (p.8)

MEUG (NZIER): "Locational vs non-locational % split within the TPM options is …a big factor in the scheme of the TPM. This is because a locational component that is too high will over-signal the importance of location and have the potential to adversely influence demand-side operating decisions compared to demand behaviour from exposure to nodal pricing alone. This has the potential to deliver a less efficient outcome" (p.8)

MEUG (NZIER) "Charging mechanisms. The trick…is to identify the cost recovery mechanism(s) that will limit potential adverse impacts while still meeting the pricing objectives of cost recovery. This in turn suggests to us that analysis of the Authority charging options needs to pay particular attention to the impacts on demand side operating behaviour. We see this is a particularly important component in the cost-benefit analysis in the next stage of the TPM review process. There is another complication. In the presence of network scale and scope economies, grid charges should be set between the incremental and standalone costs thereby mimicking the conditions that would be found in a contestable market" (p.9)

MEUG (NZIER): Economic objectives of the TPM:

- Least cost grid services
- Cost reflective, Market like – transparent
- Subsidy free
- Adaptive and dynamic
- Identify beneficiaries
- Minimise distortionary impacts (p.13)

MEUG (NZIER): "In the next iteration we would be looking for more discussion on how the setting and reset processes should be aligned with the AoB and residual charge and how they should be affected by changes to the configuration or use of the grid." (p.28)

MEUG (NZIER): "Hogan… cost allocation should be on the best approximation of all types of benefits (reliability, economic and public policy related benefits)... beneficiary pays needs dimensions of 'fairness' because the government regulators mandate the scope of both transmission investment and cost recovery and then they 'compel participation' on the basis of benefits arising." (p.4-5)

Meridian: Moving forward the Authority should consider the following issues:

(a) Major pricing issues should be determined as objectively as possible and be independently verifiable, and important charging decisions should be the outcome of applying a clear rule or methodology, and that decisions that materially impact on parties should be made by the Authority (not Transpower) where possible;
(b) It is important to ensure that deeper connection and area of benefit charges relate to the actual beneficiaries of those assets;
(c) Charges should be adaptable so that they reflect changes in use and benefits in a manner that is predictable and robust. They need to be adaptable to significant one-off changes as well as incremental change. The setting of predetermined thresholds or review triggers will be an important part of implementing this successfully;
(d) Transmission pricing should be kept as simple as possible (p.3)

Nova: "it is important that any changes or the implementation of the TPM is considered in the broad context of the costs of electricity production and distribution." (p.1)

Transpower: The following four principles should apply to any TPM option:

- Cost application should be time-neutral;
- Customers should be treated equivalently;
- Avoid unnecessary complexity; and
- Transparent (p.4)

Transpower: "We recommend that the Authority, in considering TPM reform options, expressly considers those impacts and seeks to avoid pricing options that may discourage efficient consumption, investment and corporate structure decisions (or encourage inefficient consumption, investment and corporate structure decisions). More generally, the objectives for the TPM, including the relative weighting of static and dynamic efficiency outcomes, should be informed by the macro level outlook for the sector." (p.5)

Trustpower: Objectives for transmission pricing

- "Primary objective is revenue adequacy…
- Secondary objective is for transparent, stable long-run prices
- … Associated objectives are for endurance and equity: Endurance contributes to stability and transparency, and equity contributes to endurance. However, neither are objectives in themselves.

When objectives conflict they should be prioritised in the order listed above" (p.6)

The Authority has conflated cost allocation and pricing
Orion: the Authority has confused cost allocation with pricing. Cost allocation helps us to understand the revenue to be recovered, but there is no need to link it with prices (p.4)

The Authority should consider transmission assets sales
Rangitihi (p.1-2), Te Houtaewa Maori Trust (p.1), Vision Far North (p.1-2), Waiharara Primary School (p.2)

The Authority should adopt the efficient component pricing rule
ASEC for Electra and KCE (p.12-13), IEGA (ASEC) (p.13)

The Authority should consider the effect of emerging/disruptive technologies
Network Tasman (p.5), Transpower (p.5), Mr Peters (p.1), NZ Steel (p.3) Ross Clark (p.2)

The Authority should consider non-TPM related price shocks
PowerNet submitted that before committing to staged implementation the Authority should consider: (1) the Commerce Commission's approach to price changes in relation to the 2015 price quality path determination; and (2) the price increases faced by OJV customers in July 2006 and April 2007 (PowerNet provided this information in its submission) (p.5)

Trade-offs between static and dynamic efficiency
MEUG (NZIER) "It seems to us that the Authority is trying to use the TPM options to bridge the gap [between operational and planning efficiency]" (p.5)

Trustpower (Creative): Pricing efficiency should be prioritised over planning efficiency. (p.iii)

PwC "There are trade-offs between static and dynamic efficiency… While dynamic efficiency is more important when considering future investments, allocative efficiency is currently very important given Transpower’s limited pipeline of future investments" (p.6)
Also: Molly Melhuish (p.4)

Trustpower: TPM should only be considered to achieve dynamic efficiency after considering the following: changes to the market design; changes to planning policies; revenue regulation (p.8)

9 Specificity of the guidelines

Genesis (Castalia): "the problems the Authority seeks to address should relate specifically to the TPM guidelines, rather than how these guidelines are operationalised by Transpower." (p.4)

IEGA (ASEC): It is not the Authority's role to produce highly prescriptive guidelines (p.vii)

MEUG: More prescription in the guidelines is warranted for the residual because Transpower should not be asked to consider populating the TPM when judgement is required for difficult and partly or largely non-engineering criteria (p.3)

NZAS: "Transpower's discretion should be limited to matters where it has superior expertise, such as in the implementation and efficient operation of the revised TPM" (p.24)

NZ Steel: "we expect EA to be prescriptive around the guidelines and not leave these decisions to the discretion of Transpower" (p.3)

Southland region: "Some of the implementation detail is best kept for Transpower's round of consultation – however, the implementation issues should not unravel the process or undermine the principles that those who use the infrastructure should pay for it." (p.6)
Also: Ms Dowie (p.2), Venture Southland (p.6)

Trustpower: "the Authority has exceeded its role in determining transmission pricing guidelines as required by the Code, and is proposing methodologies instead" (p.28)
Also: ENA (p.7)

10 The effect of Transpower's operational review

Transpower's review has addressed many of the issues with the TPM
MRP (p.1, 5), PwC (p.6, 8) Westpower (p.3)

Genesis (Castalia): Allowing for Transpower's proposed variations, the remaining inefficiencies are $3 million net benefits in present value to $52 million net costs in present value. This is somewhat at odds with the Authority's statement that problems with the TPM "may exceed $100 million present value." (p.4)

MRP: Most of the static inefficiencies in the current TPM have been addressed (p.5)

Transpower's review provides a useful way to continue to improve the TPM
PwC (p.6), West Coast Electric Power Trust (p.3), West Coast joint submission (p.4), Trustpower (p.12)

Any TPM proposal should be evaluated against the outcome of Transpower's review
Alpine Energy (p.2) MRP (p.1), TNT2 (p.2, 5), Transpower (p.3)

Transpower: "We recommend that the Authority update its problem definition in light of those decisions [Transpower's operational review], perhaps this could be done as part of the post project review with Transpower." (p.3)

Transpower's operational review has resulted in minimal changes
NZAS: "Transpower's recent operational review…can only make a fundamentally flawed allocation methodology less flawed." (p.17)

Unison: "Transpower's operational review has resulted in only minor changes in the incidence of charges and therefore has made it a relatively benign exercise" (p.9)

The Authority has approved changes which are in conflict with its proposed TPM
Alpine Energy: The Authority stresses its preference of a congestion-based rather than a peak-based approach to transmission pricing. The Authority has not explained how the approval of N=100 impacts on its proposed TPM (p.2)

11 Problem definition: general comments

No problem with current TPM/problem definition overstated
AECT (p.1), Northpower (p.3), TLC (p.7)

ENA: "The ENA is of the view that the case against RCPD has not been demonstrated and that it should be considered against other options." (p.12)

Orion: The TPM review has confused cost allocation with pricing, which has led to an overstatement of the problem (p.3-4)

Powerco: the rise in charges after investments have been made is not a problem, because the rise would occur no matter what allocation method was used (p.2)

Trustpower: "We do not agree that these problems exist with the current methodology for the following reasons:

- the recent grid upgrades have resulted in decreased differences in nodal prices and an increase in HVDC and interconnection charges. This is consistent with what would have been expected during disclosure of Transpower's plans during the regulatory process: Revenue adequacy has been achieved and LRMC has decreased…
- The current TPM has adapted…
- The recent major upgrades were anticipated and discussed for many years before actually occurring and the TPM is therefore cost reflective.
- The Authority has provided no evidence that the current TPM creates explicit cross subsides that will result in inefficient grid bypass that cannot be managed through the prudent discount policy.
- … there is no empirical evidence to suggest that the current planning process is inefficient…

- no proposed method is considered generally superior to the existing arrangements. The survival of the current TPM under the stresses of continuous review suggests that it is durable…" (p.11-12)

Vector: Problems with the TPM have been overstated or mischaracterised, making them appear material when they are not. (p.3)
Also: Transpower (p.1)

Approval of the Authority's problem definition
Alliance Group: "the Authority has… defined the problem with the current TPM" (p.2)
Also: Community Trust of Southland (p.1), Dongwha New Zealand (p.1), E-Type Engineering (p.1), Export Southland (p.1), Federated Farmers Southland (p.2), Genesis (Castalia) (p.3-4), HW Richardson (p.1), Invercargill Licensing Trust (p.1), JK's & Wbe (p.1), Lewis Windows (p.1), Market South (p.1), Meridian (p.7), McIntyre Dick and Partners (p.1), Otago Chamber of Commerce (p.1), PowerNet (p2), Queenstown Chamber of Commerce (p.1), SBS (p.1), Southern Institute of Technology (p.2), Southland Manufacturers Trust (p.1), South Port NZ (p.2), Southland region (p.3), Stabicraft (p.1), Venture Southland (p. 6)

Meridian: "a single methodology cannot simultaneously reflect costs, benefits, congestion, platform externalities and relative elasticities. Pragmatism and trade-offs are required. The focus should be on solving the most significant and high value problems, which Meridian believes the Authority has focussed on." (p.8-9)

MEUG (NZIER): [The Authority] has adopted a more pragmatic 'principle driven' approach to defining the problems with the current TPM" (p.12). However, "Applications A and B imply radically different estimates of the scope of the current misallocation", and seem to be trying to address different problem definitions (p.19).

NZCID: "We acknowledge limitations within the existing transmission pricing methodology (TPM), which …are likely to send inefficient signals to the market regarding the actual costs of electricity transmission." (p.1)

Transpower: "the OWP contains the clearest definition to date of the problems the Authority sees…" (p.1)

The problem definition work hasn't progressed
Orion: "the problem definition discussion is short on empirical information" (p.2)

PwC: The problem definition hasn't changed significantly since the problem definition working paper. (p.5)

Trustpower (Vince Hawkesworth letter): "With each round of consultation we become more confused by exactly what problem it is the Authority is attempting to solve" (p.2)

Inefficient and inequitable distribution between load and generators
Vector: "[The options working paper] does not address the real problem with the current TPM, which is the inefficient and inequitable distribution of transmission charges between load and generators." (p.1)

Authority should clearly define and quantify the problem before proceeding
Counties Power Consumer Trust (p.2)

12 Problem definition: HVDC

The HVDC is the controversial part of the TPM and should be addressed
Powerco (p.2), Transpower (CEG) (p.101-102)

Meridian: "Removing the arbitrary charging mechanism for the HVDC is the "low hanging fruit" in this reform process." The HVDC charge has long been in dispute and is not durable (p.8)

HVDC charges do not reflect costs or benefits of assets
Meridian: "The HVDC charge is imposed on an arbitrary subset of users and does not reflect the costs or benefits of these assets" (p.7)
Also: PowerNet (p.2) Ms Dowie (p.2), Transpower (CEG) (p.101-102)

Transpower (CEG): "the chief rationale for the charge should be to recover efficiently the long-run costs of the link without causing undesirable distortions." (p.101-102)

The case for change for the HVDC charge is not clear
WPI: "the case for changing from the current HVDC charging arrangement is less clear." (p.2)

13 Problem definition: not adaptive and wrong price signals

TPM not adaptive/wrong price signals
BusinessNZ: the status quo isn't sufficiently adaptive to new circumstances and doesn't incentivise the appropriately efficient response (p.3)

The current charging regime provides sufficient signals for regions
EMA Northern: "The current charging regime does provide sufficient signals for regions to economise on their energy use." (p.2)

Transpower's review may address or partially address this perceived problem
Orion: The increase in N under Transpower's review may address this problem (p.2)
Also: Unison (p.8)

Transpower (CEG): "[Transpower's operational review] indicates that the TPM can send appropriate price signals and can adapt – and relatively quickly" (p.1, 18)

Response to peak avoidance signals is not evidence of a problem
Fonterra: If users avoid peak demand periods, this does not indicate a problem. Avoiding periods of peak demand on the grid assists with deferring the need for further transmission investment and should be encouraged" (p.6)

14 Problem definition: not cost reflective

There is a problem with cost reflectivity/cross-subsidies
Alliance Group: "Otago/Southland businesses and consumers are being overcharged by $64 million per annum under the terms of the current operative TPM" (p.2)
Also: Community Trust of Southland (p.2), Dongwha New Zealand (p.2), EIS (p.2), E-Type Engineering (p.2), Export Southland (p.2), Federated Farmers Southland (p.3), HW Richardson (p.2), Invercargill Licensing Trust (p.2), JK's & Wbe (p.2), Lewis Windows (p.2), Market South (p.2), McIntyre Dick and Partners (p.2), Otago Chamber of Commerce (p.2), Preston Russell Law (p. 1), Queenstown Chamber of Commerce (p.2), Ms Dowie MP (p.1), SBS (p.2), South Port NZ (p.3), Southern Institute of Technology (p.2), Southland Manufacturers Trust (p.1), Southland region (p.1), Stabicraft (p.2), Venture Southland (p.1)

Meridian: The HVDC allocation is not cost reflective and this is a problem (p.1)

NZAS: "NZAS was built to make use of an excellent hydroelectric resource at Manapouri which was too large for any anticipated local load. NZAS was later expanded to facilitate the development of the Clyde high dam. Hence, NZAS was located in its current position to allow for port access and to minimise the need for transmission. With a high load factor, NZAS is an ideal transmission customer as the transmission assets are continuously utilised… Auckland by comparison grew organically because of the natural advantages the location has for residential living. These advantages did not include nearby economic energy resources. As a result considerable expense has been, and continues to be, applied to transporting electricity to Auckland. With a large residential base, Auckland demand is 'peaky' and the transmission capacity built to supply Auckland is only fully utilised for small proportions of a year... Because of these characteristics, the economic cost of providing transmission services for NZAS is considerably lower than the economic cost of transmission to Auckland." (p.18)

PowerNet: "PowerNet agrees with the EA that a problem exists with the current TPM… particularly concerned about the current cross-subsidies that exist between regions" (p.2)

TNT2: "We are increasingly aware that there may be parties that are cross-subsidising the recovery of economic transmission assets under the current TPM." (p.2)
Also: NZAS (p.19), Unison (p.4), WPI (p.1)

Unison: "experienced in excess of $10 million per annum of increased transmission interconnection charges, but has seen little evidence to support that consumers in Unison's regions have received benefits." (p.3)

Overcharging can lead to inefficiency
Transpower: CEG notes that disparity between benefits and charges can lead to the following:

- "customers will make sub-optimal investment decisions that impact adversely upon Transpower's investment costs, harming dynamic efficiency; and

- parties will alter their grid usage in undesirable ways to avoid those outlays, reducing static efficiency" (p.3)

A flat-rate works well for a shared service
Auckland Regional Chamber of Commerce: "The Chamber's understanding of the current approach of charging a flat-rate across the country for the shared national grid appears to work well." (p.1)

Transpower (CEG): "The service that Transpower provides to its customers and the manner in which it charges them bears no resemblance to a restaurant (or a potato farm or a business managing a fleet of Toyota Corollas – similarly false analogies that have featured in earlier papers)." (p.20)

Charge imbalances will smooth out over time

Auckland Chamber of Commerce: "the status quo allows any cross-subsidy" to net off over time" (p.1)
Also: Counties Power (p.11)

PwC: "The problem definition is…selective in places… other regions prior to 2004…will have been funded by Upper North Island consumers to an extent greater than their private benefit" (p.5)

Cost reflective pricing will not improve efficiency for sunk costs
PwC: "Cost reflective pricing has little or no impact on sunk investments and price discovery is only important when a new investment is being considered." (p.5)

The problem could cause NZAS to close
PowerNet: "A decision by NZAS to close Tiwai due to say a $20 million over-priced ICR would have a damaging impact on the economy and wealth of the Southland region with the loss of 800 direct and 2,000 indirect jobs." (p.2)

A degree of smoothing of charges is administratively efficient
PwC: "there is always a level of smoothing of charges across assets or customer categories (in order to minimise pricing volatility or promote intergenerational equity). A trade-off exists between economically pure approaches, that are difficult to implement in practice or to understand, and administratively simple and fair prices." (p.5)

The view of socialised costs is based on the definition of regions
EMA Northern: "in the region from Taupo north – more than 50% of New Zealand's commercial enterprises – already contribute more than their share of revenue to Transpower through existing network user charges" (p.2)

Other infrastructure costs, such as for the road network, are subsidised
EMA Northern: "Taxpayers (who are also energy users in the north of Taupo region) have significantly subsidised the building of essential common infrastructure assets south of Taupo. This is especially the case with the road network where the extension of the road network…is the result of subsidies from the north of Taupo region" (p.2)

A cross-subsidy does not exist or has not been established
Transpower (CEG): "From an economic perspective, in the presence of significant fixed, sunk costs, all that matters is whether prices are subsidy-free, i.e. between incremental costs and stand-alone costs… The short-run incremental cost of transmission is equal to the cost of losses and any constraints. These short-run costs are reflected in the differences in wholesale spot prices between nodes. In other words, all transmission grid users pay a price that is at least equal to the short-run incremental cost of supply… The remaining fixed costs of the existing transmission assets are recovered through a series of fixed charges. It is safe to presume that none of these fixed charges exceed the stand-alone cost of supplying transmission services to any particular customer. This is because if the transmission charge levied upon a particular customer did exceed that level then it would rationally disconnect from the grid – and stand alone, as it were. The existing TPM is consequently subsidy-free." (p.22)
Also: Powerco (p.3)

Transpower (CEG): "the concern expressed in the Options Paper about the 'cost-reflectivity' of transmission costs appear not to be motivated solely by efficiency considerations. Rather, they seem to be based also on notions of equity… that is not to say that there is no merit in seeking to implement a more equitable allocation of charges… 'fairer' charges have the potential to be less contentious and more durable" (p.27)

Trustpower: "we do not consider this to be an efficiency concern unless a cross subsidy is created by the allocation. The Authority has not shown this to be an issue" (p.12)
Also: Buller (p.10), Counties Power (p.11)

Counties Power: Modelling to establish a cost socialisation problem would involve "comparing total transmission revenue earned in the Upper North Island with the total costs for operating the Upper North Island network." (p.11)

Current charges may lead to a cross-subsidy in the future
Buller: "the landscape is changing as a consequence of new technologies which threaten to reduce this [standalone] cost. Therefore it is of increasing importance to have transparency and cost reflectivity in transmission charges so that investment in transmission alternatives can be assessed efficiently. BEL considers the economic efficiency argument to be less about cross subsidies, and more about signalling the potential over-recovery of stand-alone costs" (p.10)

A separate charge for overheads could address any perceived problem
Powerco: If Norske Skog is an example of a problem, this could be addressed by a separate overhead charge for offtake (p.3)

15 Problem definition: fails to support discovery of efficient investments

The Authority has not established that past transmission investments were inefficient (and why)

Orion: "The Authority's analysis of private benefits using uncapped SPD suggest that for most recent investments, private benefits well exceed costs". Further, the analysis does not give the full picture i.e. reliability (p.2-3)

PwC: "The current grid approvals process is robust and decisions are made by an independent regulator that can access and rely on expert advice." (p.5)

Transpower (CEG): "It would be inappropriate to conclude, with the benefit of hindsight, that decisions were wrong" (p.1, 29)

Unison (p.9)

There have been inefficient transmission investments
CHH: "A large proportion of the increased charges relates to investments that ... should not have been made, should have been deferred or were made on an inappropriate scale." (p.2)

Cost reflective pricing can lead to more efficient participation in investment decisions
Meridian: "a mis-alignment of the costs and benefits may affect scrutiny of new investments, potentially leading to overbuild…While Meridian agrees with these concerns, we note that it is not possible to create a pricing mechanism which has perfectly aligned incentives. For example, an LRMC charge will cause parties facing congestion to advocate for early investment and AoB/SPD charges will, to some extent, make beneficiaries of an investment indifferent to that investment…the primary goal here should be to increase the degree of alignment between transmission costs with private benefits and to improve transparency as to where private and national interests diverge." (p.9)

NZAS: transmission charges have an important role to play in promoting efficient investment by supporting the discovery of efficient transmission investments (p.23)

Efficient investment of historic assets should only be considered in the TPM for reasons of durability
WPI: "the historic issue of over built transmission assets is outside the EA's direct remit, but we believe it should be a consideration in the TPM design because it may later affect the durability of a new TPM" (p.2)

16 Problem definition: not durable

The Authority has not established that the current TPM is not durable
PwC: "The Authority has not yet put forward a convincing case that the current TPM is not durable. In our view it has worked well over time." (p.5)

Transpower (CEG): "there is ample scope to address issues through incremental reform of the current guidelines, which suggests that the TPM is durable, irrespective of the ongoing controversy, which would persist under any option." (p.1)

Trustpower (Creative): the difficulty in establishing a better option than the status quo indicates that the current TPM is durable (p.vii)

Unison: "This problem is open to interpretation. Looking at…the introduction of a deeper connection charge…Vector may well become the new Meridian, by paying for a large amount of transmission charges; and the deeper connection charge would in effect become the new HVDC, with ongoing lobbying" (p.9)

The existing TPM is not durable
CHH: The existing TPM is not durable (p.7)

CHH: "the quantum and uncertainty around future transmission charges is negatively impacting on our ability to make investment decisions for our future production" (p.2)

Molly Melhuish: "the separation of responsibility for …[transmission pricing and investment approach], between Commerce Commission and Electricity Authority will cause continuing problems" (p.4)

17 Status quo and the base option

Preference for the status-quo
AD Harwood Limited (p.2.), Auckland Chamber of Commerce (p.1), Counties Power (p.9), Electra (p.2) IEGA (ASEC report) (p.20), Northpower (p.1), NZ Energy (p.1), Trustpower (p.32), West Coast joint submission (p.2, 4), West Coast Electric Power Trust (p.2, 3), Westland Milk Products (p.3), Westpower (p.1, 8)

AECT: Does not support any of the Authority's proposals (p.1.)
Also: CG McCullough (p.1), Vector (p.1)

EMA Northern: "EMA cannot support the…proposed changes… Other than distance from generation assets there appears to be no demonstrable justification for making the proposed change" (p.2)

ENA: The Authority has not provided evidence that there are issues with the status quo (p.6)

Kawatiri Energy: At least until the Part 6 review is completed (p.1)

KCE: But if the EA were to persist with the proposed options KCE would favour the base option plus application B, with charges allocated to load on the basis of AMD or RCPD (p.2)

Orion: TPM review should be abandoned due to problems with the problem definition, investment decision-making, cost allocation versus pricing, and the DME framework (p.1)

Pioneer: "consumers and local generators are being required by the Authority to cross-subsidise the major users and larger generators, all of whom are the key beneficiaries of the transmission system" (p.2)

Powerco: There has not been a material change in circumstances, but if there was Powerco would prefer a tilted postage stamp option. (p.2)

PwC: "it is not clear that the options, as presented, will be workable in practice."(p.4)
Also Unison (p.4)

PwC: "it is not clear that the options will deliver outcomes that would be expected in workably competitive markets." (p.4)
Also: Top Energy (p.11)

Ross Clark: "Are the utilities going to continue 'business as usual' and ultimately become the owners of what is termed 'stranded assets'? Surely a better option is to work together" (p.2-3)

Top Energy: status quo involves "fewer judgement calls that lead to substantial shifts in cost between parties" (p.9)

Trustpower: "Electricity supply is arguably on the cusp of radical change…it is arguable that any changes made today will be durable and stable in the medium to long-term" (p.32)

Consideration of the status quo is necessary
Northpower: The Authority should genuinely consider the existing status quo (p.2-3)
Also: NZWEA (p.1), PwC (p.4), TLC (p.7), Unison (p.17)

PwC: consideration of the status quo is a matter of good regulatory practice (p.4)

Unison: the Authority should consider the status quo or some enhancements to it (p.17)

Unison: "the proposed methods may be volatile and lead to outcomes where the full set of beneficiaries of some transmission interconnection investments are not identified as beneficiaries (e.g., because of the low frequency of particular load-flows). In particular, the insurance aspects of the inter-connection grid may be effectively ignored, allowing for free-riding. We believe these issues would need to be addressed" (p.9)

An incremental approach would be preferred to substantive changes
TLC (p.9), West Coast Electric Power Trust (p.3)

Genesis: The Authority should consider an enhanced status quo option (p.5-9)
Also: MRP (p.1)

Genesis: The Authority should consider a mixture of change options that seek to improve the status quo as well as more significant changes" (p.5-9)
Also: Genesis (Castalia) (p.32)

KCE: The status quo is preferred, but if changes are required gradual change is preferable to radical change (p.2-3)
Also: Electra (p.2)

NZAS "No regulator can ever reach a point where it knows if an allocation of resources is optimal or not; it can only make incremental changes using available information about current and anticipated effects" (p.11)

PwC: Such adjustments are able to be made within the context of the current TPM (p.6)
Also: Westpower (p. 3)

Pioneer: None of the options are supported. "[The Authority should] focus only on options for [the] dynamically efficient allocation of the HVDC charge" (p.6)

Westpower: incremental reform through Transpower's review is likely to be more durable (p.3)

Moderate reform should be considered
Transpower: The Authority could consider a more moderate reform, for example, the existing connection charge plus a regional RCPD charge based on undepreciated values plus an HVDC charge and RCPD-based residual charge (possibly using HVAC costs (p.6)

Transpower (CEG): Transpower's simpler base option would:
- allocate sunk costs to beneficiaries, with more modest wealth transfers;
- reduce the probability of private benefits and transmission charges becoming out of step;
- address timing problems caused by the prioritisation of the deeper connection charge;
- signal congestion through the RCPD charge;
- be simpler (p. 100)

Transpower (CEG): Two examples of moderate reform:
- the base option with a modified AoB charge (with a more efficient time profile) and RCPD-based residual, without deeper connection;
- a customised interconnection rate to offtake customers in different regions e.g. based on islands, the existing interconnection regions, or graduated rates (p 9-10)

Supportive or partially supportive of the base option
CHH (p.1)

Alliance Group: "delivers a market like approach where those who receive the benefit of infrastructure pay for it without the addition complexity of adding LRMC and SPD."
Also: Community Trust of Southland (p.2), Dongwha New Zealand (p.2), E-Type Engineering (p.2), EIS (p.1), Export Southland (p.1), Federated Farmers Southland (p.2), HW Richardson (p.2), Invercargill Licensing Trust (p.2), JK’s & Wbe (p.2), Lewis Windows (p.2), Market South (p.2), McIntyre Dick and Partners (p.2), Otago Chamber of Commerce (p.2), Otago Southland Employers’ Association (p.2), Preston Russell Law (p.2), PowerNet (p.4), Queenstown Chamber of Commerce (p.2), Ms Dowie MP (p.2), SBS (p.2), Southern Institute of Technology (p.2), Southland Chamber of Commerce (p.1), Southland Manufacturers Trust (p.2), South Port NZ (p.2), Stabicraft (p.2)

Buller: If issues (including transition) are addressed. Support is also dependent on optimisation of the deeper connection charge (p.5, 11, 14)

BusinessNZ: The base option "appears to strike the right balance between what might be considered as more theoretically correct approaches, and the benefits being sought. (p.3)

Contact: But further work needed. "Contact does not yet have a final view as to the optimal composition of the components" (p.1)

Fonterra: Cautiously supportive of the base and base plus SPD options (p.6)

Meridian: Prefers SPD, but out of the options presented in the paper supports the "Base" option, as it is the simplest (p.2)

MEUG (NZIER): "Application A (Base Option) delivers the greatest progress toward an efficient re-allocation of costs for a given implementation cost". MEUG still has concerns about the reallocation of sunk costs. NZIER has conducted analysis of the "winners and losers" under Application A (p.25-27)

Ms Dowie: "most fairly reflects the deeper grid connection and efficient grid utilisation and rightly encourages the building of demand close to generation assets" (p.2)
Also: Southland region (p.6), Venture Southland (p.6)

NZAS: Support base option with nodal pricing, deeper connection charge, area of benefit, kvar charge (if justified), residual charge (if needed), with no transition. Prefer to extend the application of AoB and deeper connection (p.36)

WPI: "Suitable pragmatic but effective approach" (p.1)

The options, in general, have some merit
NZCID: "We consider the options outlined in the Paper to more accurately reflect the true costs of transmission than the status quo…" (p.1)

NZCID: "We hold no specific preference as to which option (base, SPD or LRMC) is adopted, but emphasise the value of simplicity." (p.1)

TNT2: "In principle the options presented as the Authority's base option have merit. However, we question how feasible the options are in practice." (p.2)

18 LRMC component

Supportive or partially supportive of the base+LRMC option
Nova: "Nova supports the application of the LRMC charging methodology as it focuses of future investment" (p.5)

TNT2: "the LRMC concept has merit in principle [but adds] complexity to the base option without an obvious increase in benefit" (p.2)

Transpower (CEG): "an LRMC price could, in principle represent a useful addition to the TPM. A key potential benefit is that, unlike the deeper connection, AoB and SPD charges, it would provide an efficient time profile of prices, under which the signal would strengthen as the need for new investment approached, and weaken afterwards. This would meet one of the key objectives in the problem definition…[CEG does] not consider that there would be material benefits in this instance, given the point in the investment cycle" (p.82-83)

Trustpower (Creative): The Authority should establish a stable and transparent pricing method based on transmission LRMC over the typical life of user investments, and establish a surcharge that ensures revenue adequacy and that follows Ramsey pricing. (p.vii)

Supportive of LRMC but not as part of the Base+LRMC package
ENA: LRMC should be investigated as a standalone option (p.11)
Also: Powerco (p.2, 6-7), Unison (p.6), Marlborough Lines (p.9)

ENA: "The Base Option plus LRMC approach is not consistent with ENA's previous submissions (p.11)
Also: Marlborough Lines (p.9)

MRP: "a standalone LRMC charge would be cleaner and more transparent mechanism for signalling the value of future investments" (p.3)

Tilted postage stamp
ENA: another option would be a simple allocation method consistent with LRMC, such as a tilted postage stamp charge (p.11)
Also: Powerco (p.7) Transpower (CEG) (p.104)

Orion: "consider tilted postage stamp as a simpler option to achieve [geographic targeting]... if that remains an objective in the final proposal" (p.3)

Transpower (CEG): Potential titled postage stamp options include:

- "an up-to-date estimation of the array of 'private benefits'…
- reapplying the 53:47 split that applied from 1993 to 1996, i.e., 53% to North Island load and 47% to South Island generators (noting that this allocation related to Pole 1 and Pole 2 – not Pole 2 and Pole 3)…

- a simple 50:50 split between South Island generators and North Island load…
- using an allocation of the share of flows across the link…

One of the key trade-offs would be between trying to get the most accurate picture of private benefits on the one hand, and trying to keep the approach relatively simple on the other." (p.104-5)

Recommending further investigating LRMC as part of a package
Genesis: "consider the LRMC Charge as part of an Improved Status Quo option" (p.5)

Genesis: "further consideration of the LRMC charge will need to consider how the signals it provides interact with other price signals - particularly Transpower's demand response programme. We suggest that a LRMC can only be effective if it compliments these price signals and avoids over signalling" (p.8)

Powerco: "dynamic efficiency could potentially be enhanced by including a forward-looking LRMC-based element in the charging mix, for new investments only, and we would urge the Authority to investigate this approach" (p.3, 7)

Problems with LRMC in general
BusinessNZ: "where transmission investments are centrally planned, Transpower's transmission pricing is about cost recovery, not about providing locational signals. By the time the investment is approved, it's too late for signals." (p.2)

CHH: "its practical application is likely to be highly contentious…The numbers are so large that we question whether they are sustainable given all of the other TPM components… [and may force the exit of consumers]" (p.4)

Fonterra: "[is] not supportive of the Base + LRMC option on the basis that there are numerous uncertainties with the LRMC component and none of these assets are within Transpower's regulated asset base to be charged on" (p.3)

Meridian: "an LRMC charge likely to be too complex / controversial to apply effectively" (p.2)

Meridian: There are calculation difficulties (p.24)
Also: CHH (p.4)

Molly Melhuish: "The LRMC charging mechanism is the problem not the solution (see the Lazar paper on Smart Rate Design). LRMC pricing for network tends to involve high fixed charges, which directly compete with DER energy options (PV and even firewood). They assure revenue recovery for network investments even if they are not used and useful." (p.4)

NZAS: "we doubt that adding a specific LRMC charge would achieve efficiency gains in excess of the deeper connection charge, the AoB charge and nodal electricity pricing. Both deeper connection and AoB charges should encourage behaviour consistent with achieving dynamic efficiency." (p.35)

NZAS: Investment signalling through the Commerce Commission's grid investment process can be as effective as investment signalling from an LRMC charge (p.35)

Powerco: "do not agree that an LRMC-based allocator should signal short-term congestion, as this is already achieved by the wholesale electricity market's nodal pricing" (p.7)
Also: Meridian (p.2), Trustpower (p.17)

Transpower (CEG): "because LRMC oscillates through time, so too do the benefits that any such price signal can deliver." (p.83)

Trustpower: "the LRMC charge proposed by the Authority is, in our view, neither stable nor transparent." (p.17)

Trustpower (Creative): "It is generally accepted…in the transmission context – DWL will be lowest if the long-run efficiency objective is treated as paramount and prices are set to LRMC… However, every electricity market has different characteristics…" (p.4)

Problems with the charge focusing on future investments
Contact: "it would seem unusual to pay for future grid upgrades, without receiving any of the benefits to help cover the charge." (p.2)

Fonterra: Uncertainties include demand forecasting, expenditure forecasting, and changes to capex which may result in LRMC charge being inappropriately applied (p.3)

Genesis (Castalia): "the signals from LRMC charges could work against those from other charges…parties that would benefit from an investment would face high charges (as a result of the LRMC charge) prior to an investment being made, and then again pay higher charges once the investment is made given that they now benefit from the underlying asset where the investment has been made" (p.30)

Meridian: "Pre-funding through the TPM is inherently unstable and results in participants 'paying twice' for a single asset...which may impact durability" (p.6, 24)

NZAS: "the consultation process provides a signal based on a real proposal, whereas a LRMC charge reduces the residual charge until the point the investment is made, at which time the deeper connection charge or AoB charge take over the charging of the relevant parties for the actual cost of the asset. This "borrowing" from the residual "revenue bucket" distorts the price signal sent to parties not affected by the future investment by temporarily reducing their charges" (p.35)

Unison: "the LRMC methodology [needs to align] with the allocation methodology once the investment has been made. For example, the effected party(s) would have the opportunity to reduce demand to defer the investment; and the same parties would be paying for the investment once it had been made." (p.15)

Minimal benefit due to low investment outlook
MEUG (NZIER): Adding LRMC has "Minimal impact due to low forecast investment. Adds complication to the allocation process because of the different methodology used." (p.18)

Also: Trustpower (p.17)

WPI: The package is too complex for minimal extra benefit (p.1)
Also: Trustpower (p.17)

Problems with the LRMC charge design
ASEC for Electra/KCE: "if there are 5 years until an investment is considered likely to occur, and an alternative project exists which can reduce net coincident demand by 10MW in each of those years, then the project should receive a credit for those 10MW in each year that it operates. However, the description in the TPM Options Paper appears to suggest that a credit will be paid to the project in just the first year, and that additional credit will only be paid in subsequent years if demand is further reduced again." (p.13)
Also: IEGA (ASEC report) (p.11, 16)

ASEC for Electra/KCE: "the charge as proposed would reduce to zero as soon as the investment has been made…However, true LRMC does not suddenly drop to zero just because a transmission investment has been commissioned." (p.13)
Also: IEGA (ASEC report) (p.16)

IEGA (ASEC report): "Referencing the charge to a single trading period introduces considerable volatility. The Authority would be wise to consider Transpower's experience with demand charges. A single peak is subject to considerable volatility from year-to-year, and the contribution of any given party to that peak is also unstable." (p.16)

MRP: "design issues that would need further consideration… LRMC charges could be quite volatile for some Transpower customers if the number of peak congestion periods is small and parties are charged on the basis of load/generation in the most recent year versus the previous year. It could therefore be preferable to socialise the overall load charges/generator credits (in the case of an import driven investment) across all loads/generators via a suitable allocator such as average MW drawn/injected during peak congestion periods. Volatility could also be combated by increasing the number of peak congestion periods… We also note that calculating LRMC charges for export driven investments that are largely contingent on new generation build could be challenging. These drivers are naturally lumpy in nature and often depend on factors unique to the entity contemplating the generation project, making them much harder to reliably forecast than an upward trend in demand." (p.4)

Trustpower: "the LRMC charge, as proposed, is only levied on annual changes in demand or generation at the period of peak congestion makes it particularly volatile. It would not be nearly stable enough to support parties making long-lived investments, as those investments would only gain benefit in the first year, and risk receiving negative benefits in subsequent years – and any further potential for benefit would disappear completely after the transmission investment was made" (p.18)

Trustpower: "peak congestion is likely to be much less predictable than peak demand, and therefore EDBs may struggle to notify their customers in advance of when an LRMC charging period was imminent" (p.18)

Trustpower: "Levying [LRMC] charges on the basis of coincident peak demand, which is more predictable, and across all demand and generation in a region (not just the incremental change) would be more transparent and stable, thus improving the efficacy of the charge" (p.18)

Problems with the signal not being preserved downstream
Trustpower: "In the absence of ubiquitous half-hourly metering, EDBs would likely smear those charges over all customers on their networks, via a variable charge on consumption, which would reduce the efficacy of the signals" (p.18)

Comments on MIC as compared to LRIC and AIC
Nova: "We understand the advantages of… (MIC) for the next likely transmission upgrade, but it is not clear why this should be applied only to the increase or decrease in peak load and generation in any year? …logical to apply the MIC charge to the total peak load or capacity of any unit on an annual basis… far less volatile from one year to the next and the pricing would be a signal to all load and generation in the region." (p.5)

Transpower (CEG): MIC is likely to be more volatile than LRIC or AIC (p.82)

Trustpower: "If the LRMC charges were only levied on incremental changes in demand, it would also potentially be impractical for EDBs to identify which parties on their networks should incur those charges. EDBs would likely smear those charges over all customers on their networks, which would reduce the efficacy of the signals. Further, peak congestion is likely to be much less predictable than peak demand, and therefore EDBs may struggle to notify their customers when an LRMC charging period was imminent…Levying charges across all demand and generation in a region would be more transparent and stable, thus improving the efficacy of the charge" (p.35)

Unison: Supports further development of MIC (p.6)

19 SPD component

Supportive or partially supportive of SPD
Counties Power: Prefers the status quo, but "The SPD charge is the most accurate mechanism for determining transmission beneficiaries, and many of the earlier issues with the application of the charge have now been resolved." (p.4)

Fonterra: "cautiously supportive of the Base and Base + SPD options" (p.3)

Meridian: SPD is preferable, because it is durable, flexible, and objective (p.26)

Meridian: "the various issues identified with the SPD charge in the process to date can be substantially addressed through detailed design decisions." (p.2)

MEUG (NZIER): Support SPD in principle but recommend that the Authority weigh up the complexity and cost against the relative strength of the signals that are likely to be produced. "An advantage of the SPD is that it caps the recovery of the cost of the asset at each party's private benefit and implicitly adjusts for under use of capacity when the asset is first commissioned" (p.23). The inclusion of SPD has "no material effects on either the size of the residual or the AoB charge." (p.18)

Westland Milk Products: Prefer the status quo, but out of the options, the Base Case + SPD results in the lowest annual cost to the West Coast ($8.9m) and is hence slightly more favourable (p.3)

Not supportive of SPD in general
CHH: "the SPD charge is not needed as the AoB charge effectively covers the same ground and is simpler to understand…less stable and predictable [than]… AoB" (p.4)

ENA: Do not support SPD. SPD comes with a high risk of unintended consequences, is very complex, and has little international precedent. The interaction between SPD and other charges has not been well thought through. "The Authority … has only identified a 'try it and see' basis for the proposed capping" (p.11)

Genesis: Suggests SPD is dropped "the least likely [charge] to provide material benefit to consumers" (p.5, 8)

Marlborough Lines: "The SPD model was not designed to do anything but clear the energy market and produce prices. It is not fit for purpose to allocate transmission costs. (p.9)
Also: ENA (p.11)

Marlborough Lines: The significant number of non-empirical assumptions and the level of post-processing that the Authority must apply to achieve even a feasible solution let alone a 'correct' one is testament to this." (p.9)
Also: ENA (p.11)

Nova: "Because the SPD charge applies after the investment is made, it does not provide the same signals for future investment." However, SPD may be appropriate if the area of benefit change was impractical (p.5)

TNT2: "We remain particularly sceptical of the SPD method" (p.2)

Unison (p.6)

Unison: Do not support SPD. If SPD is considered further, the Authority should model the negative impacts on dispatch (p.6)

WPI: The package is too complex for minimal extra benefit. (p.1)
Also: NZAS (p.36), Orion (p.7)

Proposed SPD charge is better than previous versions
Trustpower: The proposed SPD charge is better than earlier versions, is less volatile and more aligned to actual benefits (p.19)

SPD will create market distortions
MRP: "creates incentives for distortionary behaviour within the wholesale electricity market as it is based on market offers" (p.4)

Also: ASEC for Electra/KCE (p.13), Contact (p.2), ENA (p.11), EPOC (p.9), IEGA (ASEC) (p.23), Nova (p.5) Powerco (p.6), Transpower (CEG) (p.85), Trustpower (p.19)

Powerco: This would distort nodal prices (p.6)

Transpower (CEG): "if this type of behaviour became widespread it could seriously compromise the efficiency of the wholesale market… (p.85)

SPD does not/may not accurately identify benefits
EPOC (p.9), Marlborough Lines (p.9), Powerco, Trustpower (p.19), Unison (p.16)

Powerco: SPD "would not recognise the option value of the assets" (p.6)
Also: EPOC (p.1)

TLC: "If SPD pricing is adopted, transparency and understanding will reduce further" (p.4)

Trustpower: "each administrative decision made by the Authority yields a significantly different distribution of benefits. This raises serious doubt about the extent to which this methodology is able to identify the true beneficiaries of an asset" (p.19)

Unison: "Unison submits that Authority should model the potential negative impacts on dispatch to fully assess whether there is any benefit, if this model is considered further" (p.16)

Not including existing assets incentivises locating where there is spare capacity
Genesis (Castalia): "Application B improves SPD's impact on load investment efficiency. This is because there are now incentives to locate where there has already been transmission investment and is spare capacity" (p.27)

SPD will create disputes over modelling parameters
Transpower (CEG) (p.85), Powerco (p.6)

EPOC: "The [SPD] charges will depend very much on defensible estimates of VoLL, and the confidence in the counterfactual outcomes." (p.11)

SPD design preferences
CHH: Support net benefit over gross benefit (p.4)
Also: Trustpower (p.19)

Fonterra: Calculate SPD on the basis of net injection. Fonterra "queries if the minimum threshold for embedded generation is high enough." (p.4)

Meridian: Allocate SPD on a three-year rolling average (p.26)

Meridian: Include instantaneous reserve (p.27)

Meridian: Include Pole 2 (p.26)

Meridian: Provisional support for a longer capping period of one month (as opposed to daily or weekly capping) as it will "increase the 'benefits' caught by the charge". (p.26)

Meridian: Supports inclusion of distributed generation (charge calculated on the basis of injection into the grid) with a threshold of 10MW (p.27)

Meridian: Support gross benefit over net benefit. Participants do not have a right to be compensated for benefits that may have been enjoyed in the past due to the geographic separation of submarkets. If compensation for such disbenefits is taken into account in decision-making, future investment decisions will be distorted because they will be made based on the historical grid configuration (p.27)

Meridian: The SPD charge should be calculated ex post and applied ex-ante (p.26)

Trustpower: "[SPD] capping should still be undertaken over a longer period. Shortages can be extremely costly, and spot prices extremely volatile. For some transmission assets, their entire "benefit" can be concentrated in just a small number of periods per year…This would be inconsistent with a market-based outcome, in which such concentrated benefits are the norm, rather than the exception" (p.35)

Supports further investigation
Fonterra (p.4)

The Authority's design changes have improved the methodology
Transpower (CEG) "changes have improved the methodology" (p.84)

20 Existing connection component

Support existing connection charge
Fonterra: Supports status quo connection as the "easiest approach" given CICs are becoming common (p.3)

Powerco: The current connection charge should be retained (p.2)
Also: CHH (p.3), Genesis (p.6), NZAS (p.26)

No strong view
TNT2: "We do not have a strong view on the approach being taken by the Authority on these aspects of the base option" (p.3)

21 Deeper connection component: General preferences

Do not support deeper connection
NZ Energy (p.3), Powerco (p.5)

ENA: Deeper connection is inefficient (p.8), Counties Power: Concerned that all options have deeper connection (p.8)

Genesis: Suggests deeper connection is dropped "inherent flaws …that are not easily resolved, as identified by Castalia's analysis" (p.5)

Supports deeper connection/principle of deeper connection
CHH (p.2), Fonterra (p.3)

EPOC: "Flow-tracing charges like the deeper connection charge have support from the economic literature (Green 1997, Bialek 1996, Kattuman et al. 2014, Pérez-Arriaga and Smeers 2003). This is because they approximate beneficiaries-pay schemes, but are less open to strategic manipulation." (p.12)

Meridian: Support the general direction of the deeper connection proposal but there are a number of design issues that need to be addressed. The durability of the charge could be improved by having a backward looking charge (p.2, 16)

MEUG (NZIER): There are concerns with the "black box" nature of the deeper connection mechanism, nevertheless deeper connection under Application A would be more efficient than the status quo (p.i)

MRP: Support deeper connection under Application B (p.2)

NZAS "supports the principle of a deeper connection charge as being consistent with the Authority's economic efficiency objective." (p.27)

TNT2 "In principle, we conservatively support the concept of deep connection (p.3)

Trustpower: There is an economic basis for applying something in the spirit of a deeper connection charge, but LMP already provides adequate signals. Deeper connection should not play such a prominent role in grid cost recovery (p.14)

Unison: agrees in principle with the Authority's rationale for including a deeper connection charge (p.5)

22 Deeper connection component: problem of inefficient behaviour

Deeper connection charge could lead to gaming, lobbying, or other inefficient behaviours
Buller (p.6), Counties Power (p.13) ENA (p.8-9), EPOC (p.12), Genesis (p. 6), Genesis (Castalia) (p.19), Orion (p.6), Pioneer (p.2), Powerco (p.5), TLC, TNT2 (p.3), Transpower (Scientia) (p.13), Trustpower (p.14),

Transpower (CEG): The deeper connection charge would result in prices that exceed private benefits, leading to distortions in behaviour. The prudent discount framework "might be able to address problems relating to exit, it cannot address some of the other potential distortions surrounding new entry" (p.72)

Arbitrary HHI methodology may lead to firms altering their behaviour to avoid charges
Counties Power (p.13), ENA (p.8-9), EPOC (p.12) Genesis (p.6), TNT2 (p.3) Transpower (Scientia) (p.13), Trustpower (p.14)

Buller: The impact of this could be addressed by adopting a broader HHI range e.g. 4,000 - 6,000. (p.6)

Parties might inefficiently bid at constrained times
Genesis (Castalia) (p.19)

Parties might bid inefficiently to avoid the de minimis threshold
Genesis (Castalia) (p.16), Pioneer (p.2, 3), Transpower (Scientia) (p.14)

Inefficient lobbying
ENA: Charge "could encourage…lobbying for connection points that reduce flow shares. For example, industrials may be encouraged to connect directly to the grid to reduce the load HHI. The Authority's suggested solution, to make more assets deeper connection assets by reducing the HHI threshold, in our view would exacerbate the issues we have identified with the form of the charge." (p.9)

Incentive to seek alternative means of electricity
Genesis (Castalia): the deeper connection charge will lead to parties in some regions seeking alternative means of electricity generation (p.19)

Parties could be incentivised to change their behaviour in order to influence their categorisation as a generator or load
Transpower (Scientia) (p.19-20)

Incentive for parties not to want to attract load
ENA (p.9)

Incentive to locate near highly loaded lines
Genesis (Castalia) (p.16, 18)

Incentive to connect directly to the grid
ENA (p.9), Genesis (Castalia) (p.16, 18)

Price sensitive customers may exit
ENA: Price sensitive customers such as generators may exit (p.9)
Also: Transpower (CEG) (p.70)

Generators may time their entries to avoid deeper connection charge
Transpower (CEG): Averaging the HHI calculation over five years may cause generators to time their entries so as to minimise exposure to deeper connection charges, which may cause cheaper generation to be delayed (p.5)

Deeper connection may discourage merger activity/encourage de-mergers
Genesis (Castalia) (p.16), Orion (p.6), Powerco (p.5), TLC (p.6), Transpower (CEG) (p.70), Westpower (p.7)

ENA: The deeper connection charge may incentivise the proliferation of small EDBs and discourage service agreements (p.9)

Powerco: "The fact that the method might need to be manipulated [to address disincentives to merge] suggests that it would not be durable, as the Authority would frequently be pressured to modify the HHI threshold. There is also likely to be pressure to change the flow tracing model used, as we understand there are at least five alternative models available." (p.5)

Deeper connection unlikely to discourage merger activity
NZAS: "There does not appear to be much strength to [comments around disincentivising mergers because]… Transmission charges are a 'pass through cost'…" and the Commerce Commission incentive mechanisms balance the incentives on lines companies (p.30)

How/whether to mitigate disincentive to merge
Genesis (Castalia): "While the Authority has thought of ways to manage these risks… the solution in our view is not to introduce further regulation and market restrictions. EDBs' size or "market share" is an accident of history, but nevertheless impacts the charges EDBs face under the DCC" (p.16)

Meridian: "Thought would also have to be given to:
a. How changes in ownership were treated;
b. How participants were defined in terms of, for example, aggregation across interconnected bodies corporate." (p.16)

NZAS: If HHI has a perverse incentive if discouraging mergers, the Authority could modify its use of the HHI or adopt another method to determine deeper connection assets (p.30)

Generators will be able to avoid charges to a greater extent
Westpower: "generators are able to avoid more of…[deeper connection] charges because, it seems, generation usage of assets is more diverse." (p.6)

23 Deeper connection component: other problems

DG can be discouraged in areas with high HHIs
Marlborough Lines: "Deep connection charges will discourage investment in generation distributed or otherwise to be located in areas where the HHI is high…For example, a generator can provide dynamic voltage support significantly reducing the need for static VAR compensation in a region such as the upper South Island" (p.8)

Flow tracing doesn't account sufficiently for security of supply
Marlborough Lines: "Flow tracing as applied in the paper makes no allowance for assets that are required to achieve the required levels of security of supply" (p.5)

Also: ENA (p.7), Contact (p.2), Genesis (Castalia) (p.15)

Flow tracing doesn't account for voltage stability, frequency and frequency stability, attenuation for transients and harmonics and other power quality benefits
Marlborough Lines (p.6)

Deeper connection may cause charge volatility
Transpower (Scientia): The charge could lead to significant volatility (p.21)
Also: MRP (p.2)

Transpower (CEG): "reclassifications may give rise to unwelcome price volatility" (p.46)

Transpower (CEG): "[To address volatility issues and their effects] Transpower could not credibly commit to apply a deep connection charge to an asset in perpetuity, since circumstances may transpire to make this impossible." (p.46)

Transpower (CEG): "the charging arrangements may result in large price changes as customers connect and disconnect. This may have a number of adverse effects, such as encouraging disaggregation, discouraging efficient consolidation, and causing 'cascading' exits, where one disconnection leads to another" (p.70)

Use of HHI causes volatility and therefore, lacks durability
Genesis (p.6), MRP (p.2), Trustpower (p.14), Unison (p.5)

TNT2: "we are not confident that HHI is stable mechanism. It may be stable for a given set of input parameters but there will always exist the temptation to adjust the HHI threshold or alter the de minimus. We note this can have dramatic effects on the charges that get allocated to parties." (p.3)

Practicality issues with deeper connection
MEUG (NZIER): There are practicality issues in relation to agreeing the methodology for calculating the deeper connection charge, clarifying the definition of capacity, and confirming the estimates of the timing of the required changes. (p.27-28)

Problem of new lines near generators
ENA: "If the connection for the new line was near one of the generators then it could easily pick up all the power flow share on the line, despite their low willingness to pay. This is not market-like or efficient." (p.7)

The charge exacerbates changes in demand
ENA: The charge exacerbates changes in demand. Charges will reduce as congestion approaches and vice versa (p.9)

Relationship with the Benchmark Agreement requires consideration
Powerco: "It is not clear if the deeper connection assets would be defined as connection assets for the purposes of the Benchmark Agreement. If they were so defined, any material changes or upgrades to the assets would have to be done under customer investment contracts (CICs), because clause 36.1 of the Benchmark Agreement states that Transpower must not change the connection assets except in accordance with

other provisions of the Agreement or the wider Code that effectively require the use of investment contracts…If an upgrade to interconnection assets had to be done under a multilateral CIC, but, sometime in the future, the flow tracing model showed that the parties to the CIC were no longer the principal users of that asset, the parties to the CIC would presumably be left paying for an asset that they may not benefit from or even necessarily use." (p.4)

Problem of binary selection between load and generation
Westpower: "Where an asset has an HHI of above 4000/5000 for load but below 4000/5000 for generation, the load customers pay the full cost of the asset, even though it is clear that generators also benefit from them." (p.6)
Also: Unison (p.6)

Different treatment of large and small loads/generators
ASEC for Electra/KCE: "The proposed approach has the practical effect of treating large and small loads (and generators) differently… The larger load does not receive an allocation of the Deeper Connection costs, but the smaller load does" (p.17)
Also: IEGA (ASEC report) (p.17), Trustpower (p.34-35)

Not transparent
Genesis (Castalia): "due to flow-tracing information not being available until after an asset has been in use, transmission customers will face uncertainty" (p.14)

MEUG (NZIER): It appears to be a "black box" - based on the judgements of its architects rather than representing the potential for asset users to club together and contract for these assets (p.13)

Failure to pick up load that should be in charge
Contact: "the HHI does not appear to pick up load in cases where it seems obvious that it should, for example CYD_ROX. In order to ensure the durability of any future TPM change, we believe further analysis needs to be undertaken on the optimal HHI settings." (p.4)

Problems with the review period
MEUG (NZIER): "the long review period …[is] unlikely to be responsive to shorter term changes in grid costs or use of the grid." (p.i)
Also: Top Energy (re Ngawha) (p.5), Transpower (CEG) (p.42)

MEUG (NZIER): "Considerable effort will be required to monitor deeper connection in practice to enable regular updates over time as usage changes" (p.13)

Meridian: It may be difficult to agree on the period covered by flow tracing and the process for resets (p.27-28)

Problem with lightly loaded lines
ASEC for Electra/KCE: "Regardless of the specific methodology used for flow tracing, there will always be a problem that a specific scenario could result in "null points" in system, or lightly loaded lines, creating very high or very low allocations to a specific transmission user." (p.15)

Durability concerns
Meridian: The deeper connection charge may have the "same sort of issues that give rise to durability issues with the current TPM [due to] … [the] Risk of poor classification decisions,… Charges falling on parties who do not benefit,… inefficient investment signals for generation and load,… May result in disaggregation of portfolios or other unintended consequences,… May be insufficiently flexible over time" (p.16-17)

MEUG (NZIER): Deemed beneficiaries may not agree they receive benefits, resulting in willingness to pay problems (p.13)

Not cost reflective
Top Energy: "Thus allocation of deeper connection charges to various distributors can vary depending on whether a neighbouring load customer has significant export capacity. This effectively random allocation of costs suggests that the proposed TPM may not deliver cost-reflective pricing" (p.8)
Also: Top Energy Consumer Trust (p.3)

Problem of embedding excess capacity
MEUG (NZIER): "embeds excess capacity in charges and averages node and zonal charges which is less efficient." (p.13)

The Authority should consider "de-averaging"
MEUG (NZIER): "Less distortionary if de-averaged." (p.13)

Promotion of deeper connection above LRMC is inconsistent with DME
Trustpower: "The promotion of market-like approaches above exacerbator-pays (LRMC) approaches is inconsistent with the pricing objectives" (p.14)

Deeper connection "predicated on industry structure" issue
Trustpower: "The identification of deeper connection assets is predicated on industry structure, rather than the geographical and topological indicators that are usually used to delineate such assets" (p.14)

Deeper connection boundary issues
Trustpower: "There are boundary issues around delineating deeper connection assets from other assets, and these are likely to detract from transparency and stability." (p.14)

Double- or under- recovery
Transpower: "Moving from the Transpower pricing asset view to determine connection charges, to an SPD element view to determine deeper connection charges could result in double or under recovery at an asset level. This is because of the numerous boundary interfaces created by the additional classification and the sheer number of assets, approximately 8,000 pricing assets or 300,000-plus FMIS assets. We consider this will be challenging for our customers, Transpower, and Auditors to validate. Currently our customers are engaged in the pricing process to ensure they are comfortable with the assets they are being charged for." (p.12)

Problem of substation allocation
Transpower (Scientia): We understand the Authority has implemented an approach that calculates the total flow through all buses and nodes that comprise a substation. Since

substations can consist of multiple buses and nodes the effect of aggregation can inflate MW allocations of substations to the generators and loads. If these increased MW allocations are not affecting all "deeply connected" parties equally, there could be an impact on the calculated HHI for the substations which may impact its deeper connection classification and consequently participant deeper connection charges…[This could affect the 3% threshold and the HHI threshold]… We don't think usage ratios in excess of 100% should be possible …which would tend to overestimate allocation of substation charges to some participants ... further consideration should be given to the approach of determining substation allocations" (p.9-11)

There are too many different allocation methodologies
Top Energy: "The EA put forward six different methodologies of allocating the deeper connection charge between the parties". This creates uncertainty (p.9-10)

Setting of HHI is arbitrary
Counties Power: "concerns with the seemingly arbitrary allocation of the transmission grid using the HHI at 5,000" (p.4)
Also: TNT2 (p.3)

Charge is highly sensitive to changes in inputs
PwC: The allocation is highly sensitive to small changes in inputs. eg, changing the HHI or the de minimis, and there is no logic between applying 5000 or 6000 HHI or 2 or 3% de minimus, (p.6-7)
Also: TLC (p.7), Westpower (p.7)

MEUG (NZIER): Has conducted analysis of how the deeper connection charge varies with changes in HHI that "illustrates the sensitivity of the allocation to the choice of level for the HHI" (p.21-22)

Trustpower: "the boundary needs to be defined in a rigorous, transparent and intuitive way, so as to minimize problems of instability and avoidance" (p.14)

24 Deeper connection component: whether it is a market-like charge

Deeper connection is market-like or is theoretically, market-like
CHH: Conceptually, deeper connection is market-like (p.3)
Also NZAS (p.31), Fonterra (p.3)

Deeper connection is administrative/not market-like
ASEC for Electra/KCE (p. iv), Electra (p.2), KCE (p.2), Unison (p.9)

Marlborough Lines: "To suggest a methodology can be market-like when the seller is able to shift all cost and risk for an asset on to a reducing pool of customers is not credible (p. 6)

ENA: It is an administrative approach. It does not represent what would have occurred under negotiation (p.7)
Also: Genesis (p.6), Orion (p5), Powerco (p.4), PwC (p.10), Trustpower (p.5), Transpower (CEG) (p.3), West Coast Electric Power Trust (p.1), West Coast joint submission (p.1), Westland Milk Products (p.4), Westpower

ENA: In practice, contractual arrangements are extremely unlikely. This was demonstrated prior to 2003, when voluntarily multilateral agreements to fund grid upgrades, did not eventuate. This led to centralised capex decisions (p.8)
Also: Powerco (p.4), PwC (p.10), Trustpower (p.5), Westpower (p.8)

Trustpower: HHI may not reflect benefits and therefore may not reflect willingness to pay (p.15)

Powerco: the deeper connection method would not correctly reflect the investment that generators would voluntarily have funded, as they do not need N-1 security (p.4)
Also: Transpower (CEG) (p.64)

PwC: "the Authority is assuming it is market-like for a few parties to agree to build the asset and then let other parties use it for free" (p.10)
Also: ENA (p.8)

Meridian: Meridian considers the proposed charge may not produce market-like outcomes because:

- "Power flows indicate physical usage, but are not a measure of the economic utility of an asset to grid users…
- The proposed HHI threshold may not be a good proxy for situations where a transmission agreement is likely to be reached.
- the share of capacity, rather than the share of flow, may be a better measure of the likelihood to contract
- some of the outcomes produced by the methodology would be unlikely to arise in real markets (p.15-16)

Market-like is not necessarily efficient
Trustpower (Creative): Market-based pricing is not necessarily efficient. Markets commonly deliver inefficient prices (p.iv)

Market-like arrangements may not fit with the Commerce Commission's FCM approach
Buller: "Market like responses may give the customer the opportunity to invest in connection assets and then benefit from that investment if and when new customers are connected…It is not clear whether negotiated, competitive outcomes of this nature will easily fit with the Commerce Commission's FCM approach… it is important for the EA and the Commerce Commission to provide a clear statement of who assumes the primary risks and rewards of asset ownership under the proposed TPM" (p.12)

May lead to legal action
Counties Power: Under deeper connection Counties "would be required to seek legal action to remedy a non-negotiated outcome." (p.15)

25 Deeper connection component: allocation

Agreement with AMD/AMI
CHH (p.3)

MEUG (NZIER): "We support the allocation mechanism that both promotes efficient investment and is simplest to implement –option 2 based on AMI/AMD." Also provides comments on options 1, 3, 4 and 5 (p.35)

Peak is preferred/is market-like
NZ Steel: "The Authority is designing a methodology with allocators that it will be difficult for grid users to influence based on usage. This would be an administrative approach… hence invalidating any claim to a market-based approach" (p.2)

ASEC for Electra/KCE: "A better measure of proportional peak capacity requirements in a single year is obtained by considering a range of half-hourly periods that might be considered "peak". [For example, the method Transpower adopted in the 90's]" (p.18)

The allocation may result in inefficiencies (ie, HAMI)
MRP: "While charging on an AMD/AMI basis is consistent in its application, it would likely result in generation inefficiencies. The evidence for this can be found in the analysis of the static inefficiencies identified as part of the current HVDC charging arrangements and the application of a maximum injection charge to South Island generators" (p.3)

Transpower (Scientia): "With the coupling of the deeper connection cost allocation to the operational decisions of participants we would expect some impact on current and future behaviour as participants seek out their most efficient outcomes given the proposed rules." (p.14)

Transpower (Scientia): AMD "Using nodal AMD as an allocator could create a distortionary peak avoidance signal… We consider this effective peak charge could create incentives on Vector (and its customers) to manage their anytime nodal peak demand to avoid increases in deeper connection costs which could be inefficient, considering:

- nodal AMD is more a driver of localised transmission investment and might be less coincident with regional peaks (regional transmission investment driver) or national peaks (generation investment driver) thus reducing its benefit in deferring larger future investments
- large transmission capacity investments have already been made (committed) in many regions" (p.16)

Transpower (Scientia): AMI "The linkage of the deeper connection charge allocation to generator anytime maximum injection (AMI) may have similar effects to those observed currently in the South Island where the HVDC revenue recovery is linked to historical anytime maximum injection (HAMI) of South Island generators". Transpower noted that "this is the same order of magnitude of HAMI-based HVDC charges faced by some

South Island generators that has led to the inefficient withholding of South Island peak generation capacity to manage their HVDC costs going forward" (p.16)

Transpower (Scientia): Charging on nodal AMD "Many distribution companies can shift load between grid exit points (GXPs) through reconfigurations in their distribution network. These reconfigurations can assist in managing planned and unplanned outages, increasing reliability to distribution customers. These periods of load shifts do not represent a normal state and can sometimes result in a new AMD at a GXP which has been allocated a greater share of the distribution load. Using the nodal AMD as an allocator for deeper connection charges could impact the incentives and trade-offs faced by distribution companies during their system management and when there is a risk of setting a new AMD" (p.17)

Transpower (Scientia): Potential impact on Transpower’s operation "[Deeper connection creates] a strong linkage between individual assets (e.g. branches and substations) and the connected nodes. This linkage can create tensions in the operation of an interconnected grid view where there can be winners and losers for changes on the grid…. its decisions may have on branch flows on the interconnected grid which can have flow-on effects onto transmission customers’ deeper connection charges… Tarukenga interconnecting transformers (TRK_T1 and TRK_T2) example provided… The change in allocations under the different grid configurations were not due to any actions of the load participants (as their modelled loads are the same) but due to external factors (grid reconfiguration), physical laws of power flow and the tracing algorithm. To the extent that these change in allocations affect the calculated HHI at or near the threshold or affect a parties utilisation at or near the usage threshold (de minimis), parties would be incentivised (more than currently) to influence Transpower’s maintenance and grid reconfiguration process to increase their private benefits." (p.17-18)

Transpower (Scientia): "[The] AMD allocator can create an incentive for nodal peak control… Given that the each node’s peak demand might not be fully coincident with national or regional peaks there could be muted wider efficiency benefits from such investments in managing the nodal peak demand…[This] could also have an impact on Transpower’s transmission investment process." (p.18)

AMD/AMI should be based on use of the asset, not another part of the transmission system
ASEC for Electra/KCE (p.16)

Deeper connection method: GXP residual profiles are a better alternative
Pioneer: "The Authority should implement a more robust and fair methodology of allocating demand. This could be achieved by using actual GXP residual profiles as calculated monthly for these consumers using the current industry reconciliation practices." (p.4)

Deeper connection method: MWh method for generators
Contact: "Change to MWH [for generators/deeper connection]" (p.4)

MRP: "Moving toward a usage based allocator, such as flow shares or MWh injection/off-take, could improve the efficiency of the allocator. However, in our view allocating charges on a capacity basis is likely to be the most incentive-free and therefore efficient approach." (p.3)

Transpower: The marginal method (MWH method) has some advantages over the Bialek method but is not suitable because New Zealand's topology will result in negative values (p.17)

Deeper connection method: capacity-based
Meridian: HHIs and cost allocation should be based on share of capacity rather than share of flow (p.5, 16)

Deeper connection method: Export and import based method
Trustpower: Deeper connection" A separate ruler could be run over the grid to determine which assets would materially impact parties' ability to export generation to or import electricity from the grid, if those assets were removed (one at a time). Many of the assets classified as deeper connection in the options paper would be unlikely to qualify using this mechanism." (p.34)

Deeper connection method: a zonal approach
Unison: "the Authority consider alternatives to the HHI for the deeper connection charges, e.g. a zonal approach…For example, if X% of flows are benefiting parties in the 'y' zone, then the deeper connection charge could apply. Alternatives such as this may be more appropriate and create more stability / durability in the TPM" (p.12)

Deeper connection method: diversity of flow considerations
Unison: "The determination of assets for of deeper connection charging should also take into consideration the diversity of flow direction. E.g. in Taranaki assets should arguably be part of a greater interconnection pool based on the rationale that when electricity supply is short, the assets are used to transport flow in the opposite direction; and therefore there is a case for broad-based cost recovery…" (p.12)

Allocation: forecast peak loading
MRP: Do not agree with AMD/AMI. Prefer a usage-based allocator or a capacity basis or, even better, forecast peak loading. This would be simpler and avoid the need to consider prudent discounts where capacity exceeds usage." (p.3) "To the extent this may result in any inefficiencies, we would support consideration of how a prudent discount policy could apply" (p.4)

Allocation: Calculate AMI at grid injection point/not maximum injection at the station gate
Trustpower: "the deeper connection charge for embedded generators should be levied on the basis of maximum injection from the distribution network into the grid, not maximum injection at the station gate. There will need to be some way of fairly allocating export charges on those networks which have more than one embedded generator" (p.34)

Allocation: charges should be balanced for customers that are offtake at some times and injection at other times
PwC (p.10)

26 Deeper connection component: other design choices

Should the deeper connection charge be deeper or shallower?
MEUG (NZIER): "The choice of the HHI cut off is critical. A more detailed explanation of the driver of the sensitivity as well as comparison of the expected effects of a lower HHI on the efficiency outcomes sought by the Authority seems to be needed for the next iteration of the analysis of the options" (p.28)

MRP: There are significant problems with HHI, but if HHI must be used HHI=5000 is better than a higher or lower HHI. Decreases in HHI would reduce efficiency. (p.2)

NZAS: support an even deeper charge than the deeper connection charge proposed in the Options Paper (p.29)
Also: CHH (p.3)

TNT2: "we are concerned at how far deep connection can pragmatically be pushed. Where difficult definitions are required to try to determine what is and what is not deep connection, then greater incidence of gaming and unintended consequences occurs." (p.3)

TNT2: higher HHIs might be less susceptible to gaming and unintended consequences (p.3)

Transpower (Scientia): an even deeper conection charge would increase revenue recovered through deeper connection, increase allocation to generators, and reduce allocation to mass market demand (p.12)

Unison: "Authority could consider a lower HHI threshold cut-off, below 4,000". This still suggests a small number of parties use the asset (p.5)

Should HHI be calculated separately for generation and load?
Genesis (Castalia): A separate calculation could overly influence generation signals (p.15-16)

NZAS: Generation must be considered separately to load because an asset can be 100% relied upon by load and generation (p.28)
Pioneer: "We do not understand the assumptions about power flows. Is power assumed to go in only one direction on the HVDC? How is load and generation taken into account at each GXP?" (p.3)

PwC: Separate calculations does not reflect market interactions. In a workably competitive market it would be likely that the load parties using the asset would seek a contribution towards its construction from generation (and vice versa) (p.13)

PwC: "The HHI calculation would be more convincing if it considered load and generation together." (p.13)
Also: ASEC for Electra/KCE (p.15) Meridian (p.2, 5, 15-16)

De minimus
Top Energy: "A 5% [de minimus] threshold would be more reasonable and ensure only significant users of an asset are required to pay for them." (p.10)

Transpower (Scientia) "the value of the usage threshold becomes more crucial at a lower HHI threshold." (p.13)

PwC: "It is difficult to construct a compelling logic that the best de minimus charge level is 3% rather than 2%" (p.7)

Gross flows will overestimate allocation to generators
Transpower (Scientia): "The use of gross flows for generators will tend to overestimate allocation to generators that are electrically further away from an asset". This may not impact the overall results (p.8-9)

Net flows will underestimate allocation to loads
Transpower (Scientia): "The use of net flows for loads will tend to underestimate allocation of loads that are electrically further away from an asset". This may not impact the overall results (p.9)

No support for a congestion charge
MEUG (NZIER): "We argue against the addition of a congestion charge to either the AoB or deeper connection charge for the following reasons:

- a combination of other options e.g. SPD and LRMC can provide a clear signal of the beneficiaries of current assets and the allocation of the costs of investment to improve capacity.
- the congestion charge is complex and it is likely to be difficult to distinguish this signal from the other cost allocation signals." (p. 35)

Agree or partial agreement with the use of HHI
CHH: (p.3)

NZAS: "In using the HHI, the Authority appears to have identified a credible mechanism for defining deeper connection" (p.31)

More work needed on HHI
Meridian: More work is required to identify which asset should be subject of the HHI test, and whether any assets, in addition to the HVDC, should be excluded as a matter of principle (p.15)

Treat each retailer as a load party
PwC: "If the HHI calculation were to treat each retailer as a load "party" at each node, the HHI results would look quite different." (p.13)

The Authority should consider the threshold for "predominantly used"
Unison: "If the HHI is introduced, what is the threshold for ‘predominantly used’?" (p.5)

HHI should be compared to a but-for test
IEGA (ASEC report): "It would also be useful to compare the results of the HHI analysis against the results of the "but for" / incremental cost analysis" (p.17)

Request for electrical diagram
IEGA (ASEC report): It would be useful to see an electrical diagram to see whether the network that is not allocated as deeper connection makes sense from an electrical network perspective (p.17)

27 Deeper connection component: optimisation

The Authority should consider optimising stranded assets (either by Transpower bearing the cost or by spreading the cost of stranded assets)
IEGA (ASEC report) (p.14), Marlborough Lines (p.7), MEUG (p.2), NZ Steel (p.1), PowerNet (p.4), Trustpower (p.34), Unison (p.8), Westpower (p.5),

ASEC for Electra/KCE: "the relevant assets could be optimised down to the capacity required to provide service to the expected load for the reasonably foreseeable future (maximum 10 years)…This has a sound economic foundation, is consistent with the ECPR" (p.6)

Buller: The TPM must recognise circumstances where transmission customers would not agree to pay for the existing service potential of deep connection assets if negotiations were taking place today

- Most of the current transmission infrastructure was built without regard to market-like principles and/or economically efficient outcomes (p.3)
- It is fundamental that any retrofitted deep connection charge requires optimisation as well as utilisation adjustments (p.5)

Meridian: The Authority needs to consider whether the entire risk of excess capacity should fall on those deemed eligible to pay (p.2)

Nova: Optimisation would:

- "reduce the immediate cost impact of new transmission investments on users,
- extend the charges over a longer time frame, and
- more fairly reflect the worth of transmission assets that are no longer fully utilised" (p.3)

NZ Energy: "The reality is that if …[disconnection in the West Coast] did occur, the recoveries for those assets would have to be spread across Transpower's MAR" (p.4)

TNT2: "we would expect both the Commerce Commission and the Electricity Authority to pressure Transpower to rationalise its assets." (p.2)

Optimisation could mute the peak avoidance signal
IEGA (ASEC report): "ORC should be used instead of RC, but optimisation should be restricted to the quantum of transmission capacity (and hence the associated costs), and not be extended to consider the cost of alternative sources of delivered energy. [ie, optimisation could have the effect of muting an efficient peak avoidance signal which could, in turn, incentivise investment in efficient grid alternatives]" (p.14)

Charging optimised assets through the residual is problematic
NZAS: "To the extent that the residual charge relates to any uneconomic fixed assets that ought to be rationalised, no pricing mechanism will convert inefficient revenue into an efficient charge. However, it is outside the mandate of the Authority to address revenue related issues" (p.34-35)

Not optimising will create a "death spiral"
Marlborough Lines (p.7)

If Transpower assumes the risk of stranding, a higher return may be warranted
Buller: "if Transpower accepts the risks and rewards of asset ownership, then the Commerce Commission must accept higher returns for Transpower" (p.5)
Also: PowerNet (p.3)

Direct connects should pay a risk premium to compensate high stranding risk
Network Tasman: "with regard to direct connected load the risk of asset stranding is much higher. A market-like price would reflect this differing level of risk by incorporating a higher risk premium in the return required from directly connected customers" (p.4)

Exit provisions for deeper connection should be defined
ENA: "it would be normal commercial practice to define the exit provisions…it does not necessarily hold that there is a cost that must be recovered from other users…Such practices do not apply to so-called deeper connection assets as they are not subject to contracts" (p.9)

ENA: "The Authority's contention that the assets would be revalued and that this value would re-determine pricing is also incorrect. The accounting value of the asset does not necessarily change due to the exit of a customer" (p.9)

28 Deeper connection component: examples of misallocation

Examples of misallocation: Clyde/Islington
Pioneer: "Unintended consequences could include generators north of Clyde reducing their generation to avoid incurring Deeper Connection charges for transmission assets from Twizel down to Roxburgh. This would likely occur when generation at Clyde and/or

Roxburgh was reduced and flows are southward from Twizel to Roxburgh. It is also conceivable that the cost of these Deeper Connection charges will be factored into spot prices in anticipation of these events." (p.3)

Pioneer: "Pioneer understands the Authority's estimate of our transmission charges includes us paying for transmission assets all the way up to Islington. The Authority's estimate of our injection of 41GWh pa represents approximately 0.5% of transmission from Clyde southwards. It is inconceivable that we are a key beneficiary of these assets hundreds of kilometres from our generating plant." (p.3)

Examples of misallocation: Haywards substation buses
ASEC for Electra/KCE: "If we define network assets as assets used by a large number of parties, it makes logical sense that assets between a Connection Point and a network asset are classified as Deep Connection or Deeper Connection. However, it does not make sense that the party is then allocated Deeper Connection assets "beyond" the network assets. Logically, once the power flows have reached a network asset, from that point on the relevant flows are all contained within the networked system. However, some of the Deeper Connection assets for PRM – namely transformers T1, T2, and T5 at Haywards substation – appear to be embedded between buses classed as network assets and have no direct connection to assets directly feeding PRM" (p.17)

Examples of misallocation: Counties Power
Counties Power: "Counties Power not paying a deeper connection charge on the 220kV assets because - owing to an accident of history - a sufficient number of companies are connected, while Counties Power is subject to the charge on the 110kV assets because for historical reasons only a few companies are connected." (p.13)

Counties Power: Disputes its deeper connection charges for future transmission investment between Otahuhu and Wiri as other EDBs will use it and the investment's primary driver is security of supply. Counties has little ability to influence the investment (p. 13-14)

Also: ENA: The rationale for the investment is to improve security of supply on Vector's network (p.7)

Examples of misallocation: GXPs being allocated remote deeper connection assets
ASEC for Electra/KCE: "concerning is the implications if remote interconnection assets change from their current status of not Deep Connection for load to Deep Connection for load… there are a number of scenarios under which the HHI could increase to a level where the asset was classed as Deeper Connection for load. These scenarios include: consolidation between loads…; the Authority decides to measure concentration at the lines company rather than GXP level; more embedded generation behind some GXPs, reducing the load flows from those GXPs and increasing the apparent concentration of the other GXPs. The methodology should be designed to be sufficiently robust that these situations would not result in a GXP being allocated remote Deeper Connection assets." (p.18)

Examples of misallocation: Hawkes Bay
ASEC for Electra/KCE: "the allocation of assets in the Hawkes Bay as Deeper Connection assets for PRM, even though there are significant network assets between PRM and those allocated Deeper Connection assets. Lesser problems also arise at MHO." (p.14)

Examples of misallocation: Pioneer
Pioneer: "Injection by Pioneer (and other embedded generation) at the Clyde node (CYD0331) is dependent on coincident demand and therefore our injection predominantly occurs outside of peak demand periods. The Authority's modelling has us paying a transmission charge of $15/MWh for off-peak injection compared with Contact's $3.90/MWh charge at the same node when their injection is more coincident with use of the grid in peak periods. This is a perverse outcome… We are likely to spill water and wind to avoid uneconomic transmission charges much more than we currently do" (p.3)

Pioneer: "If Transpower bills Pioneer directly and not other embedded generation within CYD (which includes a rapidly increasing amount of domestic solar PV) we would be subsidising other generation which is responsible for materially increasing our level of injection at CYD" (p.3)

Example of misallocation: DGs - Hokitika
NZ Energy: "the GXP at Hokitika actually exports at times due to the combined DG on the distribution network then AOB/DDC charges would be passed down to the DG's. A ridiculous outcome." (p.4)

Example of misallocation: NPL_SFD
Nova: "the grid components in Taranaki north of Stratford (SFD) were built to; Export electricity from the New Plymouth Power Station (now closed) on the NPL_SFD 220 kV line, and meet the load requirements in the region, including Methanex… The grid in the region is capable of meeting the current load. It also had the capacity to export 100 MW of additional generation from the McKee Peaker Plant (MPP) with relatively minor additional expenditure. Under the proposed Deeper Connection Charge, the MPP will also be required to pay for transmission costs in the region." (p.2)

Example of misallocation: Ashburton to Bromley
Orion: The two Ashburton to Bromley lines form part of four 220kV circuits to supply approximately 1000MW of load into the upper South Island. These lines are reliability assets. "Given that future upgrade investment decisions in the upper South Island will be directly linked to the capability of the grid to deliver under contingency, this deeper connection classification seems counter intuitive… it is almost always true that investment is driven by the various post contingency states of the power system, not the normal state." (p.6)

Example of misallocation: Nelson
Network Tasman: "Historically Nelson Electricity Limited (NEL) was a non-grid connected distribution network. As a result, until April 2014 NEL's entire load was carried through NTL's Stoke GXP. After that time, NEL established its own GXP in Stoke which currently carries around 55 GWh. However, the majority of NEL's load (more than 60%) is still delivered through NTL's Stoke GXP. NTL directly passes

through to NEL its share of transmission charges. In the Authority’s calculation of the HHI for Stoke and a number of other transmission assets it appears that NEL’s entire load has been treated as if it were NTL’s. The result is that the HHI for a number of assets has been overestimated." (p.4)

Example of misallocation: Blenheim and Nelson
ENA: "In the case of the configuration of the grid around the upper South Island, because the main transmission lines were built first to Nelson and then a 110kV line run in a loop through Blenheim, Blenheim attracts the deep connection charges for the 110kV in addition to a share of the lines to Nelson using the flow tracing method… [however] if the grid had been built first to Blenheim… Nelson… would attract the… charges for the extra assets." (p.9)

Example of misallocation: Kikiwa to Stoke
Marlborough Lines: [The proposal] "leads to Marlborough Lines paying a portion of the charges from Kikiwa to Stoke and all of the charges from Stoke to Blenheim. Conversely if the lines had been constructed in the reverse direction i.e. the 220kV lines taken from Kikiwa to Blenheim and then the 110kV taken from Blenheim to Stoke, the proposed TPM would result in quite different charges." (p.10) "The Authority cannot reasonably conclude that the implied deep connection 'contract' that MLL would be party to would represent the contract and the investments that would have occurred…" (p.7)

29 Area-of-benefit (AoB) component

Support or partial support of AoB
CHH: " the allocation is consistent with the regulatory investment approval process. This provides a fairly robust way of identifying the beneficiaries" (p.3)

Fonterra: "supports further investigation of the AoB charge and suggests the EA consider how this could include an element of exacerbator pays" (p.4)

Genesis: Further consideration and refinement of AoB is warranted (p.5)

Genesis: "the AOB Charge marginally out-performs LRMC and other beneficiaries-pay methods (including the DC Charge). This is primarily because the AOB Charge aligns more closely with Transpower Grid Investment Test and is relatively simple to apply." (p.7)

Genesis (Castalia): "an AoB and a residual charge would deliver the greatest efficiency gains, under Application A or B. This is largely because AoB charges avoid negative impacts on efficiency in other areas of the electricity industry" (p.31)

Meridian: "Meridian supports the Authority’s proposed application of such a charge to economic as well as reliability investments" (p.20)

NZAS: It complements the deeper connection regime (p.31)

NZAS: "Our view is that the [AoB] charge would be market-like, as the parties who would pay for the asset would likely have been willing to negotiate with Transpower for the asset to be built had they had the opportunity and the collective decision processes to do so" (p.31)

TNT2: "the AoB approach is an approach with merit that has been used internationally. In principle we conservatively support an AoB approach to new investments." (p.4)

TNT2: "It does also seem feasible that for existing investments that have suitable GITs associated with them, (that is, post-2004 major investments), the AoB approach could work." (p.4)

Unison: Agree in principle with AoB, but the current allocation method inequitable. Also have concerns about how the charge interacts with the deeper connection charge. The Authority needs to do further work (p.5)

Detail of charge lacking
Powerco: Uncertain as to the treatment of entries and exits and uncertainty as to how the AoB and deeper connection interact where deeper connection assets change over time (p.5-6)

Do not support/issues with AoB
ENA (p.10), NZ Energy (p.3), Powerco (p.6)

Buller: There are too many variables in the area of benefit charge. The Authority needs to provide more information about how the charge will actually work in practice. (p.13)

Meridian: Supports the beneficiaries-pay principle behind the AoB charge but the charge could be contentious and AoB has disadvantages when compared to SPD (p.2, 5)

Trustpower: AoB is unlikely to comply with Ramsay pricing principles, is likely to degrade efficiency, is likely to lack transparency and stability, and is unlikely to facilitate efficient participation in the planning process (p.17)

Identification of beneficiaries must be objective and consistent/identification may require judgement
Fonterra: "The Working Paper notes that identifying beneficiaries under the AoB charge can require judgement. Fonterra encourages the EA to consider how a revised TPM could minimise the use of discretion." (p.5)

Meridian: "There is no clear method for determining how "benefit" will be assessed under the GIT. The determination of benefits needs to be robust and transparent given the likely financial consequences." (p.21)

MEUG (NZIER): "GIT and actual costs/benefits may differ materially" (p.13)

Orion: "It would be interesting to know how those benefits were determined, as allocation on a consistent basis would seem appropriate." (p.7)

PwC: "We can foresee controversy over how beneficiaries are described in any grid approval documentation" (p.7)
Also: Meridian (p.21-22), Transpower (p. 81)

TNT2: "For core grid reliability investments the benefits are not necessarily defined and these tests are minimum cost assessments" (p.4)

Ex ante – requires "heroic assumptions" but minimises distortions
Trustpower: "[Bushnell] While dependent upon potentially heroic assumptions, an ex-ante determination of benefits at least minimizes the risk of distortions to market behaviour in the pursuit of manipulating the measurement of benefits." (p.7)

Charges may exceed private benefits/difficulty in relation to reliability investments
Powerco: For reliability investments (p.5)
Also: ENA (p.10)

Westpower: Due to the allocation mechanisms (p.6)

AoB may incentivise free-riding
Trustpower (Bushnell): "Once a firm judges that enough benefits to other firms have been identified for a project it supports to go forward, it can hope to "free-ride" on the future expansion by concealing its plans in the hopes of avoiding a cost allocation" (p.5)

AoB could incentivise lobbying
ENA: "potentially significant incentive to lobby to be excluded from the AoB" (p.10)

Powerco "Each area of benefit decision point would represent an opportunity for argument" (p.5)

Marlborough Lines: "While the applications to the Commerce Commission may be a useful way of identifying beneficiaries, it does not appear to offer any objective or quantifiable way to allocate costs amongst beneficiaries…It will likely lead to litigation [reducing durability]… The GITs are a net social benefit test and while they identify at an aggregate level the net benefits of investments (if the regulatory has made a correct decision), not every implied beneficiary as an individual may have accrued private benefits in excess of their share of the investment…The reason why regulators are the ones that need to make these decisions is because the risk appetites, values and preferences of the individual parties are so varied that, in practice, they are unable to reach agreement…In making the assumption that every beneficiary based on a GIT is willing to pay, and applying charges on that basis, the Authority will create the cross-subsidies it purports to remove" (p.8)

Marlborough Lines: The Authority is considering "whether the areas of benefit should be dynamic over time. This seems to acknowledge that the GIT method is not a durable method for applying a beneficiary pays approach" (p.9)

Trustpower: "Stakeholders can be incentivised to actively steer modelling methods and assumptions in the direction that would lower their contribution to AoB charges" (p.17)

Trustpower: "Ex-ante benefit determination can motivate concealment of future plans, as their revelation could attract charges in future" (p.17)

Westpower: "The area of benefit charge may incentivise parties to try to not be identified as a beneficiary of an asset (it is not yet clear to us how beneficiaries will be identified)" (p.7)

AoB could give rise to inefficiencies if implemented as currently designed
Transpower (CEG) (p.5)

AoB is not consistent with the investment approval process for economic investments because that process considers national rather than private benefits
ENA: "The current test applied by the Commerce Commission for economic investments is a net national benefit test". If the Authority thinks this should change it should explain the problem with this process. (p.10)

AoB is more aligned to the investment approval process than SPD
MRP: "supports greater alignment of transmission charging with the Commerce Commission's approvals process. We consider this [AoB] approach an improvement over utilising market offers under the Authority's previous SPD methodology. (p.3)

AoB is too complicated
Orion: AoB "strikes us as an unnecessarily complicated way to allocate cost based on use by linking it to benefits considered in the investment approval process." (p.7)

AoB should recognise disbenefits
Orion: "Since transmission investments often disadvantage parties, we presume such parties would get a credit?" (p.7)

Overlapping allocations could develop
Powerco: "a complex overlap of area of benefit allocations could also develop" (p.5)

Static inefficiencies could develop
Powerco: Entries and exists and declining demand could cause static inefficiencies and inefficient location decisions (p.5)

MEUG (NZIER): Distortionary impacts "Likely higher than lower because of the ex-ante basis of allocation and material gaps between deemed and actual beneficiaries over time." (p.13)

The AoB charge might not adapt to an increasing use of DG/problems when a load becomes a net generator
Top Energy: "it is possible that Top Energy's allocated costs under AoB would not change even if it substantially increased its exports onto the grid. However, there are two reasons to suggest that Top Energy's allocation may change if it exported 100% of the time. This would not promote allocative efficiency and dynamic efficiency.

- The EA…reviewing the beneficiaries of the AoB investments…on a 5 yearly basis. This could change the allocation of costs to Top Energy under the AoB.

- The identified beneficiaries are categories of Transpower customers (e.g. "North Island consumers"). If Top Energy exported 100% of the time it would be reasonable to view Top Energy as a generator rather than a load customer. As such it could be allocated AoB charges that are allocated to North Island generators but not charges allocated to North Island consumers… We estimate that Top Energy would face only $41,000 in deeper connection charges if it was treated as a generator (compared to $1.3 million under the status quo)" (p.6)

Top Energy: "Where a party that was previously deemed a load customer becomes a generation customer, it is unclear if the AoB charges applied to load would cease being applied to that customer, while AoB charges applied to generators would start being applied" (p.7)

Consideration would need to be given to whether AoB is associated with a participant or an asset, and how changes of ownership are treated
Meridian (p.21)

Transparency required as to the gross versus net question (as in SPD)
Meridian: "It is not clear whether the… [gross versus net benefit question that arises in relation to SPD] arise[s] in relation to Transpower's calculation of GIT benefits to be used for AoB purposes" (p.27)

Reallocation of costs between generators and consumers
MEUG (NZIER): has conducted analysis showing how charges will be reallocated between generators and consumers under the base option AoB charge (p.21-22).

Unclear whether AoB is low cost
MEUG (NZIER): Least cost grid services? "Unclear. Likely to be not least cost based." (p.13)

AoB is likely to be cost-reflective
MEUG (NZIER): Cost reflective? "Yes – costs known from GIT business case." (p.13)

AoB is partly market-like
MEUG (NZIER): Market like – transparent? "Partly – uses GIT benefits data so could be used under a 'contracting' model." (p.13)

AoB is not adaptive
MEUG (NZIER): Adaptive? "No – allocation of costs is ex ante GIT based for each investment and is therefore fixed." (p.13) "The Authority proposal does not define … thresholds. The combination of the long review period for the deeper connection charges and the static nature of the AoB assessment suggest that once they are established both of these charges are unlikely to be responsive to shorter term changes in grid costs or use of the grid" (p.21)

AoB is more efficient under Application B
Genesis (Castalia): AoB should apply to new assets only, or be implemented using a staged approach. Application B further improves the AoB charge's impact on transmission investment, generation investment (because beneficiaries can easily

minimise generation costs with certainty), load investment efficiency (because it has incentives to locate where there is spare capacity, and because it is more predictable), and sustainability (because it is linked to the investment approval process) (p.25-26)

AoB is "equity" based rather than "efficiency" based
Trustpower: "Trustpower therefore sees this charge as being principally equity driven [correcting perceived inequity between regions]. As stated before, we do not believe equity to contribute to efficiency." (p.16)

Interaction with deeper connection issue
Transpower (CEG): "there would still be the problem of what to do when only some of the assets to which an AoB charge has been applied are reclassified and subjected to a deeper connection charge. As we set out earlier, there would seem to be no robust way of reconfiguring the AoB charges that are applied to the narrower suites of assets when these transitions occur" (p.46)

A MWh charge to generators could compromise the efficiency of the wholesale market
Transpower (CEG): "Levying charges on all generators based on MWh has the potential to distort the wholesale market outcomes and lead to higher prices" as "these are not 'true' short-run marginal costs – they are fixed sunk costs that have been made variable by the AoB charge, and this may lead to generators being dispatched out of 'true' merit order (ie, based on their 'true' SRMCs), resulting in inefficiently higher prices" (p.5-6)
Also: EPOC (p.11-12)

EPOC: "EPOC recommends that the AoB charge be allocated on a HAMI basis, since a per MWh charge can be distortionary during low-price periods. The area of benefit for generation for a transmission investment is the upstream (export-constrained) end. A capacity charge would discourage peaking capacity at the upstream end of the line. This is not a perverse incentive, as peaking plant should be encouraged at the downstream (import-constrained) end of the line." (p.11-12)

Opposition to the HVDC allocation

ENA: "it is not clear that the AoB charge would respond efficiently to the entry and exit of major load or generation. For example, it would seem that AoB prices would rise for other parties within the AoB if demand declines…creates static inefficiency as well as potentially poor incentives for parties looking to locate new investment." (p.10)
Also: PwC (p.11)

Meridian: Care needs to be taken in setting a trigger that enables a review or change in response to major events or incremental changes in use [including entry/exit of participants (p.21)] and benefit of transmission assets over time." (p.5)
WPI: The "current fixed costs to SI generators may be transferred to Load, increasing delivered electricity costs without material economic efficiency gains" (p.2)

A dynamic charge is favoured
MEUG (NZIER): The methodology is static (p.21)
Also: IEGA (ASEC) (p.vii)

Unison: "logical for the AoB charge to be dynamic and that charges should be able to be reallocated should the beneficiaries of the investment change." (p.6)
Also: ASEC for Electra/KCE (p.iv), Fonterra (p.4)

Unison: Nevertheless, the process by which this reallocation might occur would need to be carefully defined so that there are appropriate incentives on beneficiaries. For example, it would not be appropriate to reallocate costs where new embedded generation reduces the benefit of particular transmission investments." (p.6)

IEGA (ASEC): The methodology is static in that it ignores re-contracting, which will mean that over time charges will become mismatched with benefits, causing pressure to change the allocations or methodology (p.vii)

Pre-set adjustment threshold strikes a reasonable balance
CHH: "an AoB charge that is adjusted only when pre-set thresholds have been crossed seems to strike a reasonable balance between a charge that is not too volatile but which can adjust to a material change in circumstances" (p.3-4)

MRP: "If a periodic review process is considered preferable, we agree with the Authority's view that the AoB charges should only be altered when changes in the benefits exceed a pre-determined threshold rather than be subject to five yearly review" (p.3)

Transpower should decide how benefits are to be reassessed
MRP: "we recommend the Authority leaves the decision to Transpower as to how the private benefits for the AoB charge should be re-assessed. Our view is the process should be aligned as closely as possible to the GIT." (p.3)

A 5 yearly review for AoB will cause step changes to charges/annual preferred
ASEC for Electra/KCE: "[A five yearly review] potentially introduces step-changes to charges, increasing uncertainty. If the incidence of a charge may change over time then it is better to conduct an annual allocation." (p.10)
Also: IEGA (ASEC report) (p.17-18)

A 5 yearly review for AoB is preferred
Genesis: "any AOB Charge must have a clear and transparent review period built-in to ensure it is durable to demand and supply changes over time. In this regard, we suggest a 5 year period should be considered." (p.7)

Capacity rights informs how dynamic charges should be
ASEC for Electra/KCE: "While capacity rights have proven difficult to implement in practice in electricity networks, this hypothetical market aids understanding of whether the AoB charge should be static or dynamic. When usage patterns change in this hypothetical market environment, some transmission customers will be left holding capacity rights that they do not need, while others will require a capacity right. The capacity rights would be traded… This in turn raises the question of whether the AoB charge as proposed is the right option. An alternative approach is to use allocate optimised assets on the basis of flow shares" (p.10-11)
Also: IEGA (ASEC report) (p.11, p.17-18)

Static and dynamic approaches for AoB are both problematic
Transpower (CEG): "Because usage patterns will change over time it may be difficult to accurately identify beneficiaries under the 'static' approach and for parties to predict the charges they will face under the 'dynamic' approach." (p.78)

30 Kvar component

Support or partial support for the kvar component
MRP (p.2)
Meridian: "application …at times of peak demand will incentivise efficient investment" (p.5)

TLC: "This should incentivise generators and load to perform optimally to manage reactive support, not just recover the cost of reactive support" (p.7)
Also: Fonterra (p.4)

No strong view
TNT2: "We do not have a strong view on the approach being taken by the Authority on these aspects of the base option" (p.3)

The revenue collected will likely be minimal so it may not improve efficiency
NZAS: "no objections to the application of a reactive power charge… However… since the revenue collected … would be minimal, there may not be any improvement in economic efficiency from introducing this additional charge." (p.32)

The Kvar charge must reflect local conditions
Fonterra: "Fonterra encourages the EA to consider how this would be applied to ensure that users that have invested in this equipment to correct their own power factor are not inadvertently charged if this is applied on a regional basis" (p.4)

Meridian: "the charge must reflect local conditions…the kvar charge should not be based on current regional divides because areas within regions have very different needs for voltage support (for example, Wellington and the Wairarapa in the LNI). Rather, specific regions should be established for the purpose of the kvar charge so that areas within each "Kvar charge region" have similar reactive support needs" (p.18)

31 LCE component

Agree with the Authority's approach to LCE
Fonterra (p.3), Meridian (p.5) MRP (p.2)

NZAS: "supports the proposal by the Authority to credit the LCE against the assets that created them and to the participants that pay for those assets….This is consistent with Locational Marginal Pricing theory" (p.26)

Meridian: "supports offsetting the LCE against charges for individual connection or deeper connection assets….[because it] avoid[s] cross-subsidisation between asset classes and does not carry any practical risk of muting short term price signals or inefficient generator offer behaviour" (p.19)

Meridian: "The Authority proposes to credit the remainder of the LCE against the residual charge on the basis that this likely to be the "most distortionary" charge. Meridian agrees with this approach on the basis it is a simple option that is broadly consistent with aligning costs and benefits…If App B was selected, which Meridian strongly opposes, then the LCE credit for the HVDC would have to stay with the HVDC by parity of reasoning" (p.19)

Genesis: "this change is logical. However, we reiterate the requirement that the LCE Offset must provide sufficient revenue for the FTR market" (p.6)

Preference of status-quo arrangements/market distortion issues
ASEC LCE: "Finally, the Authority has not identified a material problem with the current allocation methodology for the LCE, and there is no need to change it. Under the proposed TPM Options, this would mean that the LCE that arises on Connection, Deeper Connection, and Area of Benefit assets should be allocated to the parties that pay for those assets. The remaining LCE can be credited against the Residual charge." (p.2)

ENA: "the status quo (attributing LCE to pools of assets) is a relatively non-distortionary method of rebating LCE. We reiterate our view that a method that targets LCE to specific assets may eliminate, or reduce, nodal price signals related to losses and congestion, introducing inefficiency." (p.6)

Powerco: Before making changes, the Authority would need to show "the change would not introduce a distortion to the wholesale electricity market by dampening the nodal price signals relating to losses and constraints" (p.7)

Modelling difficulties have not been addressed
ENA: "We also noted in our earlier submission that this approach may also have modelling difficulties; these do not appear to have been addressed." (p.6)

Preference for a 'least cost' approach
ENA: The method should impose the least administration costs on Transpower. This has not been addressed. (p.6)
Also: Powerco (p.7)

No strong view as to an approach
TNT2 (p.3)

LCE should be allocated on a link by link basis
ASEC LCE: "ASEC [previously] submitted that the LCE should continue to be allocated on a link-by-link basis, and thereby to the parties that pay for the asset. The Authority's current proposal in respect of the LCE credit attributable to individual connection or deeper connection assets is therefore supported." (p.1)

LCE should be allocated to AoB assets as it is a market-like approach and it is not highly distortionary
ASEC LCE: "ASEC does not support the proposal to credit the remaining LCE in bulk against Transpower's remaining MAR. … A party paying for the Area of Benefit charge should also receive an LCE credit for those assets….if beneficiaries did actually club together to contract for an Area of Benefit asset, the option would exist for them to collectively own that asset and thereby receive the LCE that arises on the asset… Note also that the larger the pool of beneficiaries paying for an asset, the less that the LCE credit could be said to distort the marginal price signal received by any given user of the asset. In any given half hour there is likely to be a significant difference between the beneficiaries assumed by the TPM and the actual users of an asset. Crediting the LCE generated on the transmission asset will ensure that the overall price levels for individual assets are correct over time, but will not alter the market price signals in a given half hour." (p.1-2)

ASEC LCE "If the proposed TPM were to be implemented, this extension of the LCE credit to Area of Benefit assets would mean that Auckland and Northland would receive a the LCE for the central North Island and NAaN upgrades, and the relevant identified beneficiaries would receive the LCE credit for the HVDC." (p.2)

Congestion rents could be allocated to capital costs
Trustpower [Bushnell]: "congestion rents could be applied to the capital cost of the pending project rather than applied to a general, reduction in the residual charge. I [Bushnell] view this option as very similar in spirit to the LRMC proposal, but with the correct marginal incentives for network usage" (p.18)

32 Residual component

Support for the proposed residual charge (also refer "AoB and Residual allocation to EDBs and Direct-connects" section)
Meridian: "support[s] the proposed residual charge" (p.6)

Incentive-free residual charge makes sense
Genesis (Castalia): "an incentive-free residual charge makes sense in the context of the Authority's DME hierarchy" (p.28)

The residual is too large
Contact: the residual component is surprisingly large and should be lower (p.2)
Also: NZAS (p.33)

NZAS: once the residual is minimised, the Authority can consider what services those assets provide and decide a charge accordingly (p.34)

Difficulty with identifying variable cost
MEUG (NZIER): "We suggest that the basis for this charge and the definition of what is included as variable may be difficult to identify and categorise in practice." (p.29)

AMD may incentivise avoidance

Westpower: "The residual charge may incentivise direct connect customers to reduce their AMD" (p.7)

The charge could have a distortionary impact
MEUG (NZIER): Distortionary impacts "Likely material unless charges are carefully designed to minimise distortions (Ramsey pricing for example)" (p.14)

The residual charge should be non-distortionary
Genesis "any residual charge should be non-distortionary" (p.-8)
Also: Genesis (Castalia) (p.28)

Issue with not charging generators (refer "Charging generators" section)
Vector: "the residual postage-stamp charge is not charged to generators at all [creating inefficiencies]" (p.2)

The magnitude of the residual is sensitive to assumptions
ASEC for Electra/KCE: "The magnitude of the Residual Charge is sensitive to the assumptions as to MAR, the revenue to asset value ratio, and other revenue-related assumptions [and the Authority's assumption that charges are 15% of RAB is overstated]." (p.9)

MEUG (NZIER): has conducted analysis showing the sensitivity of the residual charge to assumptions about EDB capacity (p.23-24)

Ramsey pricing
NZAS: "the focus …should be to allocate as much of the charges for assets to those that are willing to pay for them, and hence minimise the residual charge." (p.33)

Trustpower: "We agree with the Authority's assessment that a pure Ramsey charge is not practicable, and should therefore not be considered further" (p.25)

The residual charge should be based on capacity
Meridian: "Meridian considers that allocating the residual to load is supported by the economics of two-sided markets, international practice and the minimisation of distortions. Meridian agrees that the charge should be based on capacity" (p.2)

Genesis (Castalia): "Having a capacity-based charge that does not change with use of the grid is therefore more incentive-free and fits better alongside other charging options being explored by the Authority." (p.28)

Unclear whether the approach is least cost
MEUG (NZIER): Least cost grid services? "Unclear but unlikely – depends on whether Transpower costs are efficient" (p.14)

The approach is not cost reflective
MEUG (NZIER): Cost reflective? "No – by definition the cost pool that cannot be attributed directly to assets, users or locations." (p.14)

The approach is partially transparent
MEUG (NZIER): Market like – transparent? "Partly insofar as the costs are a defined, and allocated in a visible manner. Parties may be willing to contract and pay for the residual if it was seen as being necessary and efficient." (p.14)

The approach is not subsidy free
MEUG (NZIER): Subsidy free? "No – by definition is the cost pool that cannot be identified to assets, users or locations" (p.14)

The approach may be adaptive
MEUG (NZIER): Adaptive? "Possibly – depends on how adaptive and dynamic the other mechanisms are." (p.14)

Further consideration is required
Genesis: Further consideration and refinement of the residual is warranted (p.5)

Coverage and structure of the charge are important
Genesis (Castalia): "The optimal application of the residual charge is less important than the coverage and structure of the charge because its role is to pick up all remaining costs." (p.28)

Unclear whether the options provide better price signals than the status quo
Genesis (Castalia): "It is unclear whether the combination of charges that potentially provide stronger price signals (DCC, AoB, LRMC, SPD) and an incentive-free residual actually provides better price signals overall than current RCPD and HVDC charges" (p.29)

33 Applications A and B

Preference of Application A over Application B
Alliance Group: Application A is more efficient. "Under Application B, regions would continue paying for infrastructure build to benefit consumers in other areas...However should local transmission lines need an upgrade, under Application B, only local consumers would have to bear that cost. A double burden of cost would be borne; again potentially leading to a decrease in GDP and jobs in regions that needs to grow." (p.2)

Also: CHH (p.6), Community Trust of Southland (p.2), Dongwha New Zealand (p.2), EIS (p.2),E-Type Engineering (p.2), Export Southland (p.2), HW Richardson (p.2), Invercargill Licensing Trust (p.2), JK's & Wbe (p.2), Lewis Windows (p.2), Market South (p.2), Meridian (p.6), McIntyre Dick and Partners (p.2), MEUG (NZIER) (p.27), Ms Dowie MP (p.2), Otago Chamber of Commerce (p.2), Otago Southland Employers' Association (p.2), PowerNet (p.2), Preston Russell Law (p.2), Queenstown Chamber of Commerce (p.2), Southern Institute of Technology (p.2),), Southland Manufacturers Trust (p.2), Southland Chamber of Commerce (p.2), Southland region (p.2), South Port NZ (p.2, SBS (p.2), Stabicraft (p.2), Venture Southland (p.2)
Contact: prefer Application A, conditional on modelling in the next paper, and the Authority conducting further work to determine the optimal composition of the base option (p.1-2)

Meridian: "Application B would effectively mean the simultaneous existence of two TPMs. This is highly undesirable [because it would result in]… Mixed signals…Boundary disputes (ie in the case of refurbishments versus replacements)…[an] Uneven playing field…South Islanders pay[ing] twice…Complexity for operational reviews… Precedent: Grandfathering current assets creates a precedent which means that next time there are changes there will be pressure for a further layer of grandfathering." (p.12-13)

Meridian: "[Under Application B] South Island customers and generators would continue to pay for existing transmission assets in the North Island despite deriving no (or little) benefits from these assets. In addition, they would end up paying for new transmission investments in the South Island on a beneficiary or user pays basis. The inequity of this "double whammy" outcome would undermine the durability of the TPM." (p.1)

NZAS: "the adoption of Application B would lead to a more complex and confusing TPM, with two pricing approaches running in parallel for the long-term" (p.36)

NZCID: "We acknowledge that an area, such as the Upper South Island, could under Application B find itself in the future having to cover the near full costs of the next phase of transmission investment while also subsidising transmission investment to the rest of the country. Although we find this undesirable, it is no less desirable than requiring upper North Island consumers to subsidise the costs of pre-2004 national transmission investment and not receive a similar subsidy from other regions once "its turn" arrived post-2004 via NIGUP and NaaN" (p.3)

PowerNet: Prefer the status quo, but "Application A…attempts to deal with the pricing inefficiencies that exist and while being applied retrospectively may not be ideal, it is no less ideal than not correcting the existing inequities." Application B will further penalise regions where new investments are made. The Authority should consider applying Application A further back than 2004 (p.2)

Unison: "Unison’s preferred approach to any new TPM where there is significant reallocation of costs is Application A – but with a suitable transition reflecting that it is generally undesirable to make retrospective changes" (p.6)

Venture Southland: "supports Application A as this mechanism supports the Authority’s statutory objectives and it is:

- technically robust, pragmatic, reflects sound modelling and is sustainable over time, and
- promotes durability and provides a more efficient investment decision-making environment." (p.5)

Problems with Application A

Counties Power: "Application A only makes sense if the country started from a blank sheet of paper and EDBs were able to balance their benefits and costs in the grid design." (p.10)

Genesis (Castalia): "under Application A, DCCs would improve the efficiency of transmission investment, but reduce efficiency in load investment, the efficiency of retail market operations, and the sustainability of the TPM." (p.13)

Tai Tokerau Northland: Application A will lead to inefficient avoidance and disconnections. Application B provides signals for future investment. Application A promotes excessive allocation of costs to the regions. (p.3)

Trustpower: "Application A proposal would harm efficiency by introducing distortions to the short-run operation of the market with no prospect of offsetting long-run gains" (p.25)

Vector: Application A will lead to wealth transfers (p.2)

Application B perpetuates problems with the current TPM
Fonterra: "Application B would preserve the existing imbalances in transmission charges" (p.5)
Also: Business NZ (p.4), CHH (p.7), Meridian (p.1)

Fonterra: "If the EA did proceed with Application B, Fonterra would recommend that the EA consider a net MWh basis for charging, rather than the proposed gross MWh basis. Applying a gross MWh charge would inappropriately charge industrial co-generation, as often the primary reason for installing industrial co-generation is to efficiently generate steam for industrial processes and is not driven by electricity transmission use." (p.5)

Preference of Application B over Application A
Genesis: "strongly support Application B. Application B provides the critical dynamic efficiency benefits the Authority sought in this change…[Application B] minimises the significant risk of unintended consequences from changes to the TPM" (p.2, 10)

Genesis (Castalia): "[Application B] removes incentives to avoid locations with spare capacity due to investment. However, it does not overcome the incentives created by the arbitrary use of EDBs' "market share" under the DCC. As under Application A, load investment decisions will still be impacted by how many parties' use key assets. Incentives for load to connect to the grid directly (rather than to EDBs) are uncertain." "The effects of DCCs on the retail market are reduced under Application B by reducing the 'shock' of cost rises, which will only be felt when a new investment is made in a region" (p.24-25)

KCE: prefer the status quo, but Application B is better than Application A (p.2)

KCE: "Application B reduces the wealth transfer compared to Application A" (p.2)
Also: Genesis (p.2)
MRP: Application B would be more consistent with the Authority's logic that the DCC is a market-like charge (p.2)

Nova: Under Application A "consumers and generators are being required to pay charges that were never contemplated when they made investments in plant." (p.1)
Also: KCE (p2)

NZCID (p.3), Powerco (p.3), Trustpower (p.12), Westland Milk Products (p.6)

Tai Tokerau Northland: Prefer Application B over Application A because investments have already been made, and on the basis of the current TPM (p.3)

Top Energy: Application B "does not resolve the issue of ensuring those that pay are actually receiving a benefit." (p.11)
Also: Top Energy Consumer Trust (p.3)

Westpower: Application B would deliver price signals without large price shocks. Retrospective regulation is poor regulatory practice (p.9)

No apparent preference
Orion: "Application B needs transition arrangements just as would application A." (p.8)

TNT2: "applying the base option to existing assets is more likely to realise static inefficiencies, even though it might also reduce some, and we remain unconvinced that this would realise any dynamic efficiency benefits" (p.3)

Transpower (CEG): "there seems to be a concern that Application A may involve ‘too much’ re-balancing and that Application B may involve ‘too little’. The transition paths might therefore be characterised as ways of finding a ‘middle ground’" (p.91)

Transpower (CEG): "the fact that Application A would serve to reduce any such ‘wedge’ between current charges and the perceived level of benefits also represents its biggest potential drawback. In order to reduce that wedge, the transmission charges levied on some parties will need to increase. Under the proposed options, those increases would, in some cases, be substantial… giving rise to significant static inefficiencies" (p.88)

Transpower (CEG): "It follows that the biggest question insofar as the choice between Applications A and B is concerned is whether these potential short- to medium-term efficiency costs would be outweighed by the potential longer-term efficiency gains. There is also the related question of whether now is the best time to be reforming the TPM with a view to achieving those longer-term objectives" (p.89)

Transpower (CEG): "there is the question of whether it is practicable for Transpower to maintain two methodologies side-by-side, as it would be required to do under Application B…. In our opinion, these considerations would tend to steer one towards Application A"…"changing the TPM cannot affect the efficiency of investments that have already been made…which might steer one towards Application B (p.90, 84)

34 Transitional arrangements

Support for transitional arrangements
Buller: The proposals could trigger price shocks that will not necessarily increase efficiency. Price shocks could be addressed through transitional mechanisms (p.6)
Also: CHH (p. 7) Meridian (p.1), TNT2 (p.3)

ENA: "In principle, transitions should be considered depending on the basis of the costs and benefits attributed to a change in TPM...For example… reduce the impact of static losses while still signalling the benefits from changing behaviour in the future" (p.13)
Also: TNT2 (p.3)

Genesis: The Authority should "tailor implementation to mitigate the impact on those who are most affected" (p.11)

MEUG (NZIER): "The lead-in time for the price change in 2019 should give the:

- EDBs and retailers time to prepare the customers for the prospect of increased costs
- Commerce Commission time to consider how the risk of re-allocation of grid costs could be allowed for in the price paths agreed with EDBs" (p.29-30)

MRP: "care would need to be taken to minimise and transition any impacts to various parties" (p.5)
Also: BusinessNZ (in relation to SMEs) (p.4), TNT2 (p.3), Trustpower (p.28), Westland Milk Products (p.7)

NZAS: The Authority should discuss all of the transition options to show that they have been considered (p.38)

TNT2: Transition costs are too quickly ignored in CBAs and the economic costs of price shocks ignored (p.3).

Trustpower: "if the Authority wishes to pursue TPM reform to address equity issues [through beneficiaries-pay] arising from recent investment…our recommendation is that it should undertake any reform gradually, in a well-signalled fashion with sufficient transition mechanisms…" (p.12)

Trustpower: An appropriate transition could "avoid significant wealth transfers impacts; reduce the impact of regulatory risk on external capital providers; and enable the dynamic wholesale market to adjust over time to the new framework without unnecessary distortions and/or uncertainty and/or negative impacts for the New Zealand economy" (p.27)

A transition is inconsistent with the Authority's regulatory framework
No transition – inconsistent with the statutory objective: EIS (p.1), NZAS (p.40), Preston Russell Law (p.2), Southland Chamber of Commerce (p.2), Southland region (p.2), Venture Southland (p.2)

NZAS: "a decision to defer efficient prices and retain inefficient prices would, assessed on its own, not be consistent with the Authority's statutory objective" (p.40)

NZAS: "As the Powerco judgments are based on the specific legislative scheme and purpose of the then Part 4 of the Commerce Act, they do not apply to other Acts of Parliament" and do not apply to transitional arrangements for the TPM (p.40)

Trustpower: "the current TPM guidelines highlight the importance of transition arrangements for operational changes: Guideline 19 provides that "overall transition arrangements should be proposed where revision of the methodology leads to large increases or decreases in current charges" (p.27)

Transitional arrangements will preserve inefficiently high prices for some consumers
Preston Russell Law: "While we understand that some economically disadvantaged customers might find it hard to face higher prices, there are already disadvantaged customers paying prices that are inefficiently high, any transition would mean they had to keep on paying them." (p.2-3)
Also: Fonterra (p.5), MEUG (NZIER) (p.30), NZAS (p.20), Southland region (p.2), Venture Southland (p.2),

Fonterra "there is sufficient lead time from the implementation of any change for this to be communicated to those impacted by the change" (p.5)

MEUG (NZIER): The discussed timing "implies that the misallocation of costs that the Authority is attempting to correct will have persisted for another four years …and also that the assets to which the reallocation will apply will have depreciated by approximately 20 percent" (p.29)

Transitional arrangements should not only apply to EDBs
Network Tasman: "it is not clear why the Authority proposes that capping and funding of the cap applies only to EDBs, rather than all load." (p.2)

PwC: "most of the transitional options allocate the costs of transition to load or distributors only. We are not aware of any valid reason why" (p.13)

Annual maximum increase in electricity prices
Meridian: Supports a cap on the maximum increase over a three-year period (p.11)

Unison: "[new charges] phased in over a five-year period and…a cap is applied on regional increases (e.g. no more than a 5% increase in the rate of change to final delivered electricity prices" (p.7)

Long transition period needed
Nova: "An equitable way of transitioning the Deeper Connection Charge would be to defer the imposition of the charge on all existing generation assets for a period of twenty years from the date the generator was connected to the grid. …Given the age of most generation plant, such a deferral would not have an excessive impact on the overall costs on load, but it would give a clear signal that the impact of regulatory risk is considered seriously" (p.2)
NZCID: The Authority should consider a 10 year transition period to recognise the long-term nature of investments (p.1)
Also: Westpower (p.10)

Trustpower: Any transition to Application A needs to be significantly longer than 5 years (p.28)

Support alternative 4
Westpower: "If Application A is implemented, our preferred transitional provision is Alternative 4. None of the other transitional provisions provide a sufficiently graduated transition to have a meaningful benefit for customers affected by the price shocks. (p.10)

Support for an annual maximum increase in prices EDBs face, funded by EDBs
CHH: "We do not support Alternative 4 (or any variant) which is a phase-in of the new charges over a five-year period. We consider that this option would not meet the Authority's principle objectives" (p.7)

CHH: "We understand the concerns about rate shock, particularly for consumers on the West Coast and upper North Island…In order to phase in the price increases over a period of time it might be reasonable to do this by slowing down the price increases in the EDBs facing increased charges and balancing that with a slowing of the price decreases in these classes in the EDBs facing decreased charges" (p.7)

Transpower (CEG): Temporarily capping prices for EDBs "The chief reason [for significant inefficiencies] for this is that charges faced by generators and direct-connected load would remain uncapped." (p.92-93)

Given the Commerce Commission smooths price increases to 5% to 10% pa, the Authority might accept a slightly higher rate because transmission is a small component of electricity prices
Meridian (p.11)

Preserving a portion of old TPM charges would create complexity and nullify price signals
Meridian: "While Meridian supports a cap…it does not support a weighted average of old and new changes. This would be complex and the combination of old and new charges is likely to mean that the intended price signals are lost." (p.11)

A transition will not make an inefficient new TPM, more efficient

Transpower (CEG): "transition mechanisms that cap the annual increase in charges do not serve as a panacea to short- to medium-term efficiency problems. At best, they can only delay distortions to consumption decisions and, at worst, they will have no effect whatsoever." (p.92)
Also: Genesis (Castalia) "However, in some cases transitions improve how the charge evaluates by allowing more time to collect information and improve the analytical tools used to set prices." (p.23)

35 Interaction between components

Difficulty in determining whether an asset will be deeper connection in advance
PwC: In determining where an asset will be deeper connection or AoB "the Authority proposes to determine this before the start of an asset's life – i.e. hypothetical flow tracing…. Given the risk that actual load flows will differ, this is likely to prove

controversial, especially if the hypothetical analysis put the asset close to the HHI cut-off point" (p.7)
Also: Unison (p.13)

Uncertainty as to treatment where assets change over time
Powerco: Uncertainty as to how the AoB and deeper connection interact where deeper connection assets change over time (p.5-6)
Also: Transpower (CEG) (p.46)

Transpower (CEG): As we set out earlier, there would seem to be no robust way of reconfiguring the AoB charges that are applied to the narrower suites of assets when these transitions occur" (p.46)

Uncertainty around how layered charges will interact in practice
Trustpower (Vince Hawksworth Letter): It is not clear how the plethora of new charges will interact with each other and with nodal prices (p.1)
Also: ENA (in particular the SPD and AoB charges) (p.11), NZAS (re nodal prices) (p.18), Trustpower (p.9)

Unison: Any package of charges should be well integrated (p.17)

AoB complements the deeper connection charge
NZAS (p.31)

Sequencing of proposed charges is unworkable: suggest applying AoB first
Transpower (CEG) " it is not feasible to prioritise the deeper connection charge over the AoB charge since:

- it cannot be applied ex ante to assets not yet built since the actual load flow data would not be available – it would instead be necessary to use forecasts, which would create insuperable problems;
- assets may transition in and out of the deeper connection charging framework over time, leading to highly volatile charges and compromising parties' ability to engage constructively in new investment processes; and
- there would be no satisfactory way to reapply AoB charges to a narrower group of assets if certain assets within a broader asset group (such as the NIGU lines or the Wairakei Ring) are reclassified as deeper connection" (p.3)

Transpower (CEG): "If the AoB charge was applied before the deeper connection charge then, for each major new investment, the principal beneficiaries would be identified and the relevant costs allocated accordingly. Those assets could then be quarantined permanently from other charges to avoid the undesirable volatility associated with assets transferring between charges… (p.47)

Concern about level of deeper connection and AoB charge
Transpower (CEG): "[A] potential problem with the proposed levels of the deeper connection and AoB charges. ..In this respect it is important to remember that transmission investments exhibit significant economies of scale… once the land has been purchased and the towers built, there is not much difference in cost between a low and a high capacity line… There are also often more than private benefits at stake…

increased transmission can reduce market power and increase network reliability… there are also likely to be valid national security interests to 'err on the side of caution' by investing building 'bigger and sooner'" (p.52)

Suggestions as to optimal combination of charges
Genesis (Castalia): "to avoid duplicative or interfering signals, this Authority should only combine one "active" charge (either DCC, AoB, SPD or LRMC) with the residual charge… Three of the charges … will duplicate each other's signals if combined… …The design of the residual charge as an incentive-free pricing approach means any charge can be combined with the residual without duplicating or undermining price signals." (p.30)

Meridian: "the best combination for a new TPM is the current connection charge, the SPD charge (as simplified by the Authority from the version proposed in October 2012) and the new residual charge as proposed in the TPM Options paper. Such a combination would be objective, independently verifiable, adaptable to changes in grid use over time, and relatively simple and comprehensible." (p.3)

36 Interoperability between transmission and distribution regimes

Distributors are limited in their ability to pass through a TPM price signal/costs will be variabilised
Marlborough Lines: Distributors cannot pass through the pricing signal, due to regulatory requirements (e.g. Low Fixed Charge Regulations) (p.10-11)
Also: ENA (p.11), Network Tasman (p.3), Orion (p.7), PwC (p.12), Top Energy (p.5), Top Energy Consumer Trust (p.2)

Orion: Variabilising of the residual charge may lead to efficiency gains being lost (p.7)
Also: Nova (p.4), Top Energy (p. 5), Top Energy Consumer Trust (p. 2)

PwC: Disagree with the Authority's assumption that variable charges to end use customers are less likely to be affected if the residual charge is allocated to load, because the residual will be rebundled as a variable charge (p.12).
Also: Top Energy Consumer Trust (p.2)

The complexity of the options will reduce transparency
TLC: "we believe that attempting to communicate what is proposed to customers would be extremely challenging…The Authority is currently asking EDBs to make things simpler for consumers and retailers, but this proposal in TLC's view, moves in the opposite direction" (p.4)

Charges are inconsistent with the LFC regulations
TLC: "The proposed changes will make this [LFC] difficult to implement as all residential customers in a region will attract the same transmission charge. The deemed capacity of a residential customer, set at the maximum rating of a Class 1 meter, is effectively a fixed charge within an EDB's network. There is very little the customer can do to

influence it and therefore it should be passed on to the customer as a fixed charge which is inconsistent with the objective of the Low Fixed Charge Option. Holiday homes are another customer group that would be adversely effected by the proposed changes, effectively making their transmission charge fixed." (p.6)

The Authority should differentiate between customers with stable and predictable demand and customers with undulating demand
CHH: "distribution pricing for large loads are generally established on a different basis to the mass-market consumers which are commonly based on installed capacity…. distributors have recognised New Zealand's large industrial loads have quite different characteristics to the multiple small loads connected to distribution networks. The lines services they require are highly predictable with specific contracts setting out supply arrangements." (p.6)

Whether revised transmission charges will be passed through from EDBs to their customers
AECT: "the proposals could result in electricity generators paying $23m less in transmission charges each year, but this is unlikely to translate into reduced electricity prices being delivered to consumers." (p.1)

MEUG (NZIER): the options paper is silent on how grid users (EDBs) will change their approach to the recovery of grid costs from their end customers (p.25)

NZ Steel: "Direct pass-through of Transpower charges is a key requirement of contractual arrangements we have with EDBs, but we have not been able to get any indication as to how this may work under the TPM proposals or the $ implications. The options paper is silent as to how calculations can be applied at individual nodes/GXPs. This detail is critical to informed comment on the proposal and future consultation." (p.2)

37 Cutoffs: 2004 cut-off for investments / $20m to $50m cut-off

2004 cut-off is arbitrary
NZAS: "in principle the AoB charge should be extended to pre-2004 assets if a suitable proxy for the GIT can be defined to establish the area benefiting from or relying on the asset…One possible proxy is the use of flow tracing" (p.32)

PwC: "if regulation is going to be applied retrospectively this should be done consistently... The basis for the 2004 cut-off is not strong… (p.6)
Also: Tai Tokerau Northland (p.4)

2004 cut-off causes inefficient opposition to asset replacements
Powerco: "Creating a distinction between pre and post-2004 assets could also have the perverse effect of encouraging industry members to oppose the replacement of pre-2004 assets." (p.2)

The 2004 cut-off causes cost reflectivity issues and/or is inequitable
Fonterra: "Fonterra queries why the $20M threshold isn't also applied to investments made since 28 May 2004 (this query also applies to the assets included for the SPD charge)." (p.4)

NZCID: "It is clear that for whatever date the Authority identifies as the cut-off for transition to a new TPM there will be winners and losers" (p.3)

Tai Tokerau Northland: "2004 and $50 million cut-offs … exacerbate the price burden on consumers in UNI and the west coast" (p.4)

Top Energy: [Given the distinction between pre and post-2004 assets] "Top Energy would pay a larger share of the post-2004 transmission asset investments than it does currently but still pay towards pre-2004 investments…Had Top Energy known at the time, it would likely have made different investment decisions, such as earlier commissioning at Ngawha" (p.11)
Also: Unison (p.13)

Unison: submits that "the Authority consider applying the AoB approach for assets older than 2004 that are yet to be fully recovered, as an option to improve fairness and equity" (p.3, p.13)

Changes should only apply to new assets
Genesis: Disagrees with the presumption that any TPM change will apply to significant assets constructed after 2004. "The appropriate starting point is the assumption that any changes will only apply to new assets from the date of the decision" (p.10)

38 Cutoffs: The inclusion of Pole 2

Pole 2 should be excluded
Contact: Pole 2 should not be included in the area-of-benefit charge (p.5)
Also: TNT2 (p.4)

Marlborough Lines: "To try to extend this approach to Pole 2 suggests that the private benefits accruing to Pole 2 exceed that public benefits. This is arguably true for Pole 3 but for Pole 2 (which should be described as the existing HVDC) there are significant public benefits. Pole 2 provides underlying security of supply and power quality to all users in the same way as other core grid assets." (p.9)

Pole 2 should be included
ASEC for Electra/KCE: "The question [of inclusion of Pole 2]…requires broader consideration of the economic contracting framework that might apply in a market environment. Would the identified beneficiaries elect to pay, or would they elect to forgo an inter-Island connection in favour of more generation on each Island?... The whole point of the link is that it provides access to lower cost generation (particularly for the North Island) and security of supply in dry years (for the South Island). This suggests that there would have to be additional generation in both islands, and the cost of electricity would therefore be higher… an SPD simulation conducted without the HVDC

would identify higher prices in the southern part of the North Island, that is only a short-run analysis that does not consider the offsetting investment that would likely occur. …The HVDC link serves to connect the two island-based networks together, and in so doing provides "gains from trade" to both islands, delivering benefits to both that would not otherwise be achieved. As such, it might be more economically sensible to recover the costs on a basis that recognises the wide spread of those longer-term benefits" (p.10)

CHH: "We support the continued allocation of the costs of Pole 2 to South Island generators with the proviso that generators who do not benefit from Pole 2 are not charged for it." (p.5)

CHH: "the EA states (October 2012 issues paper] that South Island generators will, in aggregate, derive a private benefit from Pole 2 of about $540m PV (point estimate) against an estimated HVDC charge related to Pole 2 of about $500m PV" (p.7)

Fonterra: "Pole 2 should also be included to ensure the durability of a revised TPM." (p.4)

Meridian: "Pole 2 should be subject to the AoB charge to maintain consistent treatment with Pole 3 given they jointly provide energy and ancillary services" (p.5)
Also: NZAS (p.32)

Meridian: "It is…preferable to have HVDC assets recovered through the AoB/SPD charge and ahead of the residual, given the expected efficiency benefits (and as reflected in the Authority's DME framework)." (p.21)

Meridian: It is appropriate to include Pole 2 because of consistency with Pole 3, in particular, power flows over Pole 2 and Pole 3 are managed in a co-ordinated manner by Transpower. Further, it is appropriate to take a principles approach. "a considerable proportion of the Authority's review has been concerned with addressing arbitrary distinctions involving HVDC assets… it directly confronts the historical debate with regard to who benefits from HVDC assets and who pays". (p.21)

39 Cut-offs: inclusion of HVDC in deeper connection component

Exclusion of Pole 3 in deeper connection is not explained clearly
Meridian: considers that more work is required to identify which assets should be subject to the HHI test and whether any assets, in addition to the HVDC link, should be excluded as a matter of principle" (p.14-15)

Trustpower: "The Authority has not explained clearly why Pole 3 is not subject to the deeper connection charge." (p.16)
Also: Transpower (CEG) (p.73)

Arguments for excluding HVDC link from connection assets
Meridian: "If an HHI test suggested that the HVDC link was a deeper connection link, this would indicate a flaw in the HHI methodology rather than be evidence that the HVDC link was really a deeper-connection asset". Meridian "agree[s] that the HVDC link is not a deeper connection asset given its clear role as an interconnector of the North and South Islands and the range of benefits it provides to all grid users in both islands under all flow scenarios" (p.5)

Transpower (CEG): "Seeking to recover 100% of the costs from…[a] sub-set of generators may …cause them to respond inefficiently" (p.73)

Transpower (CEG): "From a practical perspective, HVDC and interconnection assets are differentiated and treated separately in the regulatory arrangements administered by the Commission, i.e., there are distinct revenue streams and performance measures. In this sense, they could be said to be distinguishable because they are already distinguished." (p.74)

Transpower (CEG) Reasons: "are based on the current load flow analysis (under which the supply-side HHI is met, but the demand-side HHI is not), only certain generators would pay for 100% of the costs of the link [whereas it]… delivers a much wider array of benefits…[and] the link was built so as to cater for future demand growth" (p.73)

Arguments for including the HVDC link in connection assets
Transpower (CEG): "We do not see the distinction that the Options Paper is seeking to draw between the HVDC link and assets such as the NIGU and NAaN lines. Neither of these recent upgrades is ‘required’ to connect a party to the grid – they are, after all, expanding a network that already exists. They are links that, like the HVDC, facilitate the flow of energy from one part of the interconnected network to another… If anything, the HVDC link bears a closer resemblance to a ‘connection’ asset than the other assets the Options Paper identifies, because it is actually joining two parts of the network that would, in its absence, be physically separate" (p.73)

40 The case for cost reflective charges/beneficiaries-pay

Support or partial support for cost reflective charges/beneficiaries-pay
Alliance Group "The current system of allocation does not meet the Authority's statutory obligation as it is not cost reflective and it does not drive efficient investment decisions." (p.2)

Also: Community Trust of Southland (p.2), Dongwha New Zealand (p.2), E-Type Engineering (p.2), Export Southland (p.2), Federated Farmers Southland (p.2), HW Richardson (p.2), Invercargill Licensing Trust (p.2), JK’s & Wbe (p.2), Lewis Windows (p.2), Market South (p.1), McIntyre Dick and Partners (p.2), Otago Chamber of Commerce (p.1), Queenstown Chamber of Commerce (p.2), Southern Institute of Technology (p.2), Southland Manufacturers Trust (p.2), Southland region (p.5), South Port NZ (p.2), Stabicraft (p.2), Venture Southland (p.5)

Buller: Broadly supports "Reducing free-riding on transmission investment…Redressing the growing disconnect between localised investment and localised transmission charges…Reducing the ability for parties to game the allocation of transmission charges to their advantage" (p.1)

CHH: "we are facing a material and continuing increase in transmission charges, which is unjustified as it is not driven by improved service…" (p.2)
Also: Counties Power (p.12), Counties Power Consumer Trust: (p.2), West Coast Electric Power Trust (p.3), West Coast joint submission (p.3), Tai Tokerau Northland (p.2)

Contact: "where the beneficiaries of investments (for both reliability and economic purposes) can be clearly identified, beneficiaries should pay for such investments." (p.2)

Contact: The Authority should consider adjusting charges so that they increase in line with benefits rather than being flat year on year, to reflect that utilisation of an asset is typically lower immediately following commissioning. (p.4)

Meridian: (p.2)

Nova: the numbers suggest the beneficiaries of the NIGUP line are being overcharged under the proposed TPM" (p.2)
Also: Top Energy (p.8)

Southland region: The Authority's proposals will deliver "not just the best use of the grid a pricing regime that will affect the size of transmission investment in NZ and

- Will not waste money building a grid we do not need (ie it will promote efficient future investment decision making), and
- Will not over charge consumers, both residential and industrial, for infrastructure they do not use.
- Decisions by businesses to close operations due to inefficient TPM price signals will be avoided.
- Greater certainty will be provided for future industry investment surrounding transmission pricing and encourage development close to generation assets" (p.7).

Also: Ms Dowie (p.4), Venture Southland (p.7).

TNT2: "While we would strongly oppose moving the burden of such cross-subsidies to other parties we would strongly support simple measures to remove such cross-subsidies." (p.2)

Trustpower: "Vector, Northpower and Top Energy [may] see the reallocation of NIGU and NAaN as somewhat inequitable because:

- The investment decision has already been made and there is nothing they can do to influence it;
- The benefits of increased competition are less than the increased costs of the network upgrade;
- They might have a different view on reliability and/or preferred solution than the regulator; and/or

- Their customers have previously paid for reliability investments in other regions (including the South Island) for which they get no benefits." (p.15)

Unison: "If a reliable method can be found to allocate transmission asset costs to beneficiaries then Unison would support change" (p.4)

Vector (CLEX report): For new investments, a beneficiaries-pay principle should, in principle, promote efficiency." a proper implementation of beneficiaries-pay would entail:
- Beneficiaries are properly identified
- Beneficiaries are involved in the decision making process; and
- Beneficiaries are charged in proportion to their net benefits - loads' capacity or generators' injection is not a proper indicator of net benefits as no measure of benefits is associated with AoB. (p.10)

Authority has not found a robust way of identifying beneficiaries
AECT: "The AECT is not convinced that the EA has determined a robust method of properly identifying beneficiaries" (p.2)

Contact: The Authority "must consider how to identify actual beneficiaries in the simplest way possible and whether the proposed options will be enduring" (p.1)

ENA: The attempt to identify beneficiaries of assets is illusory, as evidenced by the high sensitivity of allocation outcomes to administrative decisions (p.13)
Also: MEUG (NZIER) (p.12).

MEUG (NZIER): Externalities from loop flows create complexity for identifying beneficiaries (p.7)

Whether charges should be spread
Refining NZ: "electricity infrastructure has the characteristic of a "public good", and therefore, the Government (and its agencies) have a role in ensuring that social equity objectives are met" (p.2)
Counties Power: (p.2)

Pioneer: transmission is a national good and so charges should not be on a regional basis (p.4)

Ross Clark: "Electricity is a national asset for all NZ and pricing should be fair and equitable to all regardless of location" (p.2)
Also: C G McCullough (p.1)

Vector (CLEX report): Nodal prices give all the necessary signals for location to both loads and generators. A transmission pricing mechanism that distorts such locational signals is necessarily inefficient. (p.4-5)

Cost reflective charging should differentiate by service reliability levels
EPOC: "Ideally electrical energy should be a product differentiated by different levels of reliability (see Doorman 1975, Margellos and Oren 2015)…a [TPM] should be capable

of including such pricing models, even if they are difficult to implement in the short term." (p.5-6)

Considering separately (ie NIGU for SPD) overestimates benefits
EPOC: "In a transmission network, investments in capacity typically have synergies that must be considered as a portfolio. Charging for the sum of individual benefits of these investments can … overestimates the benefits" (p.10)

Equity should not be the primary objective of a beneficiaries-pay approach
Trustpower: Beneficiaries-pay may not promote equity, but equity is a secondary consideration in any case. In our view this approach will distort behaviour, especially when applied ex-post." (p.6, 10-11)

Transpower (CEG): "unlike efficiency – which is an objective, measurable standard – equity [which the Authority appears to be aiming for] is inherently subjective." (p.27)

41 The case for cost neutrality over the life of assets

Advantages of cost neutrality over the life of assets for valuation purposes

IEGA (ASEC report): A non cost-neutral approach for asset valuation over the life of assets (ie the saw-tooth price structure) encourages over-use of an asset when it is older (p.12)

PwC: cost neutrality over the life of assets reflects the service levels experienced by customers (ie, constant regardless of asset age (p.10)
Also: IEGA (ASEC report) (p.12), Meridian (p27), MEUG (p.23), Orion (p.4), PowerNet (p.2), Top Energy (p.10), Transpower (p.4), Westpower (p.2),

PowerNet: cost neutrality over the life of assets will avoid price shocks to customers (p.2)
Also: Tai Tokerau Northland (p.4), Top Energy (p.10)

Transpower: cost neutrality over the life of assets will avoid perverse price signals (p.4)

Transpower: cost neutrality over the life of assets will avoid arbitrary wealth transfers (p.4)

Transpower: if there is no cost neutrality over the life of assets, upgrades may be opposed, causing reinvestment difficulties (p.4)
Also: PowerNet (p.3), PwC (p.10), Top Energy (p.10)

Transpower: cost neutrality over the life of assets would be much simpler to implement than a depreciated replacement cost approach (p.13)

Older assets serve generators while newer assets service UNI load
Transpower: The replacement cost methodology … generated comparable results to those published through the OWP, however in this instance the swing toward North

Island EDBs was slightly damped by a comparable increase for the Generators. This is likely due to the relative age of TPM assets serving generators, compared to the newer assets serving North Island EDBs." (p.13-14)
Also: Transpower (CEG) (p.48-51)

Asset valuation should be based on depreciated asset value
Counties Power (p.17)

42 Allocation of charges to generators

Support or qualified support charging residual to generators
AECT (p.2), ENA (p.12), Fonterra (p.5), MRP (p.3), Tai Tokerau Northland (p.4), TLC (p.5-6), Transpower (CEG) (p.55-58), Westpower (p.6), WPI (p.2)

Counties Power: A 50/50 split between generation and load is appropriate for the residual charge (p.17)
Also: Fonterra (p.5), MRP "unless there is a demonstrable and material efficiency benefit" (p.3), Transpower (CEG), Vector (CLEX) (p.38-39)

CHH: recommend modelling "charging [generators for residual] on the basis of nameplate rating of the generator and a deemed capacity utilisation." (p.5)

KCE: Otherwise there is likely to be wealth transfers (p.2)

Vector: The differentiation between load and generation is arbitrary, biased and creates inefficiencies (p.2-3)

Vector (CLEX report): "The EA is also wrong in assuming that postage stamp charges to generators would not be competitive neutral as it could shut down low profitability generators… Back up or must run generators are normally operated based on contracts with system operators, covering all their costs including transmission charges." (p.6)

NZAS: "does not object to the approach of not charging a residual to generators, so long as the assets contributing to the residual are not connection-like assets or AoB assets that the generators rely upon to a significant degree." (p.33)

Orion: "if it is appropriate to allocate cost to generators, then consideration can be given to the least distortionary method (which based on other aspect of the options appears to be on a per MWh basis)"… But no matter where the cost falls, it will probably end up with consumers. (p.7)

The AoB charge should provide for greater allocation to generators
Network Tasman: "The options proposed in the Working Paper do not seem to fully recognise this two-sided nature of the benefits of transmission" (p.3) example – AoB for HVDC Poles 2 and 3 exclude NI generators. (p.4)

Improved dynamic efficiency from targeting generation
Counties Power: "improved dynamic efficiency will be obtained from charges targeting generation rather than targeting load. Unlike consumers, the costs of transmission are a key consideration in the location of a generation business" (p.3, 10)

Generators may not be capable of passing charges through
PwC: "distributors are able to pass these on to consumers in full. Every dollar of transmission charges allocated to distributors can be expected to be paid by a consumer. In contrast, the wholesale market is workably competitive [generators may not be able to pass the charge through]" (p.12)

Do not support charging residual to generators
Contact (p.3), Nova (p.3)

Meridian: "allocating the residual to load is supported by the economics of two-sided markets, international practice and the minimisation of distortions (p.23)

Allocation mechanism for generators requires further consideration
CHH: "the EA has been too dismissive of alternate allocations [to the distortionary MWh charge for generators]" ie AMI. (p.1)

Transpower (CEG): "peak charges based on anytime maximum injection (or HAMI) may lead to generators strategically withholding capacity" (p.56)

Transpower (CEG): "The effect of a MWh charge is that some generators may be dispatched when they have a higher 'true' SRMC than others that are not called upon. (p.79)

Transpower (CEG): "capacity based charges may cause generators to inefficiently decommission plant, or eschew adding it." (p.56)

Capacity charge for generation could be problematic for peakers/this problem could be addressed
PwC: "We agree that a capacity charge to generators would have undesirable effects for peak generation relative to baseload plant. However, the Authority's assumption that variable charges to end-users are less likely to be affected if the residual charge is allocated to load rather than generation does not withstand scrutiny" (p.12)

CHH: "The competitive neutrality concern with low capacity utilisation generators is easily dealt with by adjusting their charge on the basis of utilisation… this can be dealt with by charging on the basis of nameplate rating of the generator and a deemed capacity utilisation. With both of these being fixed, there should be no influence on behaviour… In fact it may well incentivise the offering of more capacity" (p.5)

Generator charges may be reflected in wholesale bids, as a variable charge
Transpower (CEG): "MWh charges may be factored into wholesale bids, which may result in inefficient wholesale dispatch… Usage-based charges operate as a tax on usage, deterring the utilisation of sunk assets. Dynamic efficiency requires that charges influence participants' generation and load investment decisions but minimise their impact on operational decisions" (p.56, p.78)

Also: CHH (p.3)

Fonterra: "Fonterra acknowledges that if the residual was allocated to generation, it may be passed through to users via higher energy costs. However, this will provide a price signal to load to incentivise reduced energy use and can assist with the efficient use of the transmission assets and deferring investment, more so than a static charge" (p.5)

Ramsey pricing should be considered for generators
TNT2: "we accept that where there is clear and good economic reason that Nga Awa Purua, as a generator connected to the NZ grid, may be allocated transmission charges. However, if the grid is economic in its entirety, then there is no reason why Nga Awa Purua should receive charges in excess of its joint venture owners' willingness to pay. That is, the charges should not compromise the owners' reasonable ability to recover a return on capital. We have yet to see any evidence that the grid is not economic in its entirety." (p.2)

43 Allocation of AoB and Residual charges to EDBs and Direct-connects

Allocation for AoB and residual should be the same for EDBs and direct-connects
ASEC for KCE/Electra (p.iv), Contact (p.3-4), Contact (p.3-4), Electra (p.2), Genesis (Castalia) (p.29), IEGA (ASEC report) (p.15), KCE (p.1), Meridian (p.2, 21), MRP (p.3-4), Network Tasman (p.1-2), Pioneer (p.2), Powerco (p.8), Powerco (p.2, p.7-8), PwC: "grossly inequitable and distortionary outcomes" (p.10, 11-12), Tai Tokerau Northland (p.4), Top Energy (p.4, 7-9), TNT2 (p.4), Transpower (p.4) Trustpower (p.16, 19), Unison (p.3), Unison (p.13), West Coast Electric Power Board (p.6), Westpower (p.6)

Alpine Energy: The proposed method is not cost-reflective. This will lead to durability issues (p.1)

Counties Power: "The direct customers chose to invest in the New Zealand market on the basis of the existing transmission arrangements. They have benefited for decades from New Zealand's low electricity prices. ...It is unacceptable for the government to now transfer wealth back to these companies." (p.9)

ENA: "there is no clear rationale for why some forms of allocation suit some types of charge but not others (for example AMI/AMD appears acceptable for deeper connection, but not for AoB or the residual)" (p.12)

Fonterra: this charge is instead allocated to direct-connects and EDBs on an actual use or AMD basis" (p.5)

Genesis: "limit allocation to maximum load. This would ensure the allocation is consistent across consumer types." (p.8)

Marlborough Lines: The allocation method is an inefficient, inequitable and unjustified transfer of wealth from ENBs (and their consumers) to directly connected major users. (p.12)

PowerNet: Would result in inefficient outcomes (p.4)

TNT2: "The proposition that major users should be charged on AMD (itself a distortionary approach) rather than deemed capacity because they don't use all of this capacity (incorrectly implying that EDBs do) is a nonsense and an arbitrary distinction" (p.4)
Also: Alpine Energy (p.1), Counties Power (p.16), Northpower (p1)

TLC: The effects of inconsistent allocation methods between EDBs, Direct-connects and generators are:

- to disadvantage EDBs with a large % of vacant premises and holiday homes
- the benefits of demand restraint from the LRMC charge are negated
- to discourage new customers from locating in areas of surplus capacity
- no ability for EDB's or consumers to react to pricing (p.5-6)

Transpower (CEG) In our opinion, a robust rationale has not been provided for the application of different charging parameters (and the attendant redistribution), because:

- although the capacity of some direct connect customers' connections substantially exceeds their AMD – this is also likely to be true of many EDBs;
- although EDBs may have an incentive to inefficiently suppress load to avoid an AMD-based charge, this could be avoided by retaining an RCPD charge which is measured over a large number of periods, e.g., 100+; and
- EDBs may also seek to inefficiently reconfigure their assets so as to limit their exposure to the charge, e.g., by constructing micro-grids so as to reduce their numbers of ICPs." (p.7)

Unison: "the capacity-based methodology…does not reflect the diversified demand distributor's experience and would unfairly bias the costs of transmission towards distribution consumers" (p.4)
Also: Marlborough Lines (p.10)

The allocation approach would enable direct connects to avoid the charge with DG
Pioneer: "major industrials at a distinct advantage by using net load (where installed capacity is used for all other consumers) – particularly if they have generation embedded behind load on site." (p.2)

PwC: "This approach would also enable direct connect customers to reduce their charges by using embedded generation" (p.12)
Also: Pioneer (p.2)

PwC: "The Authority should seek to avoid a situation where load customers are actively incentivised to invest in DG" (p.9)

Capacity disincentivises DG to generate during peaks
Nova: "the proposal to base the residual charge on capacity rather than RCPD removes the incentive on embedded generators to generate during peak demand periods" (p.3)

Also: ASEC for Electra "This will bring forward transmission investment" (p.4, p.12)

A difference in allocation may be justifiable due to capacity factors
ASEC for Electra/KCE: "Different types have load have different capacity factors, but that is no reason to use a fundamentally different measure of capacity for the different load types… Furthermore, notional gross capacity is nearly eight times higher than AMD for distributors" (p.iv, p.11))

A difference in allocation may be justifiable on the basis of Ramsey pricing
EPOC: "Some degree of bias may be justifiable on the basis of Ramsey pricing, however the partition of cost between EDBs and direct connect customers should really be made an explicit parameter of the methodology" (p.12)

TNT2: "In our view no allocation methodology is going to be perfect and exceptions are to be expected. A process and an exception process that recognises that certain loads have much higher elasticity than other loads seems a more reasonable way of improving on Transpower's operational review than a dramatic set of changes." (p.4-5)

Ramsey pricing is being applied
Trustpower: "it appears that a Ramsey pricing principle is being applied. However, the AoB allocation is not equitable because the capacity measure is arbitrary and disproportionate…[David Smith] although equity is not a pricing objective, extreme inequity could impact on the durability" (p.16)

Support or partial support for the allocation method in the options working paper
CHH: "The distributors [ie Vector] have recognised New Zealand's large industrial loads have quite different characteristics to the multiple small loads connected to distribution networks. The lines services they require are highly predictable with specific contracts setting out supply arrangements. Any changes in the demand for services generally requires material investments in production plant and is subject to individual consideration and negotiation (p.6)

CHH: "It would be inefficient to allocate transmission charges on the basis of installed capacities for major industrial loads as all of these have surplus capacities for prudent security of supply. If the transmission pricing methodology provides an incentive to otherwise reduce prudent security through removing surplus transformer capacity, it would then be distorting behaviour." (p.6)

CHH: support the allocation of the area of benefit charge on an AMD basis for all loads larger than class 5 (whether direct connect or EDB). Support charging on the basis of nominal capacity for the active ICPs of class 5 and below. (p.6)

NZAS: "AMD for major users is likely to provide a reasonable proxy for capacity for those customers…On the other hand, the EDBs service mass market customers whose peak demands are driven by a range of factors, including the weather… the specific measure of deemed capacity adopted by the Authority could mean that the EDBs would pay a disproportionately high amount of the residual charge…[In response, NZAS considers residual should be minimised]" (p.34)

WPI: "We agree with the EA's option approach of using a deemed capacity for each individual ICP" (p.2)

WPI: "We suggest that the EA consider allocating all ICPs, including residential ICPs and private networks behind the ICP, with a deemed capacity based on its likely AMD using indicative load indicators as a proxy for AMD. This approach should also enable EDBs to pass through these costs to end consumers transparently" (p.2)

The treatment of load and generation may lead to unintended consequences
Top Energy: "If Top Energy exported 100% of the time and Top Energy were treated as a generator, it would pay zero residual charges as generators do not face the residual charge." (p.7)

Top Energy: "The TPM needs to address instances of load parties exporting onto the grid and consider how it will be determined whether to treat those parties as load or generation or both. It is important to avoid any "double counting" [considering expansion plans at Ngawha]" (p.7).

Westpower: "the allocation takes no account of distributed generation on EDBs network. As the demand EDBs make for transmission services is net rather than gross of distributed generation, this overstates EDB demand and will over-allocate costs to EDBs… gross demand (as opposed to net demand) is not reflective of the cost drivers involved with new transmission investment" (p.6)

Capacity based charge would be difficult to avoid whereas peak charging aligns to transmission investment requirements
ASEC for Electra/KCE: The rationale for capacity based charges only holds "when charges are not intended to provide a signal about future investment." (p.3)

Fonterra: "Fonterra does not support the EA's logic in paragraph 6.97 of the Working Paper regarding the charging on a capacity basis, rather than concentrating it just on those using the grid during peaks. The transmission infrastructure is built to deal with the peak, and therefore users that cause this peak should pay. (p.5)

Molly Melhuish: "As DERs become less costly than grid investment, regulation should allow the benefit of such end-use investments to be captured by the consumer-investor… What is needed is not capacity charges, but time-dependent energy charges, extensively discussed in Lazar. It may be that capacity charges are still an efficient option; the full paper on Load Defection needs to be studied for guidance on this." (p.3-4)

Unison: "a capacity-based charge makes it more difficult to avoid the charge than the current interconnection RCPD calculation based on peaks. While this is the Authority's intention, Unison has concerns [of] this method in the context of possible decrease of electricity demand in the future, especially when distributors are constrained by regulations to offer a low fixed charge tariff option. (p.14)

Any changes to the options working paper allocation mechanisms should be treated as "new business"
NZ Steel: "We are mindful of scenarios, particularly involving capacity calculations, that materially alter these [modelled] numbers. Any such changes introduced into further EA papers must be treated as 'new-business', and not an extension of the current options and consultation." (p.2)

Direct connects require higher levels of reliability than residential customers
Pioneer: Industrials demand higher reliability (VOLL of $20,000) than residential customers (VOLL of $150 - $1000). It is therefore fair that they pay for that added reliability. (p.3)
Also: Orion (p.8)

Insufficient or inconsistent rationale for different application of charges
MEUG (NZIER): supports the underlying principle of allocating costs on the basis of access to grid capacity, but the Authority needs to clarify its rationale for its allocation method (p.i, p.18). Using different mechanisms to assess the capacity of direct-connect industrials and EDB customers (including industrial users) is "in a practical sense … an anomaly", "directly undermines the principles of the Authority approach", and "drives the need for transition options that indirectly undermine the principled approach" (p16-18). The absence of a rational "may leave the proposal exposed to challenge" (p.28).

MEUG (NZIER): "Our analysis of alternative measures of EDB capacity suggests that a more realistic estimate of EDB capacity would be considerably lower but would not eliminate the reallocation of grid cost from direct connect industrials to EDBs under the base option…) (p.24)

Preferable treatment of direct connects incentivises industrials to by-pass distribution networks
Alpine Energy (p.2), ASEC for Electra/KCE (p.iv), ENA (p.12) Powerco (p.2, 8), PowerNet (p.4), PwC (p.10), Top Energy (p.4), Westland Milk Products (p.5)

IEGA (ASEC report): "[This would result in a] large reduction in Residual Charges…[and] any Area of Benefit charges (p.11, 15)

IEGA (ASEC report): "an industrial customer that does disconnect [and connect to the Transmission network] will receive credit for any onsite generation or any other measure that they may take to increase energy efficiency (p.11, 15)

Tai Tokerau Northland: "None of this would be expected in workably competitive markets" (p.4)

TLC: Inconsistent allocation incentivises "EDBs to connect behind a direct-connect"(p.6)

Alternative: flat rate for residential customers
Nova: EDBs should pay a consistent flat rate for residential customers. (p.5)

44 Allocation of charges to retailers (versus distributors)

The counterparty should be determined by the pricing structure
ENA: " the appropriate counterparty [for deeper connection] should be determined by the pricing structure rather than the other way around" (p.6)

PwC: "It will be more credible to identify the optimal counterparty once the design of the charge is known." (p.14)

Deeper connection HHIs would be below the threshold if distributors were not the counterparty
Orion: Deeper connection "equates distributors with load, when load could just as easily be conceived as being retailers or even end consumers, in which case we suspect the HHIs rapidly decrease below the threshold. (p.6)

Making retailers subject to transmission charges would be costly
Contact: "Contact agrees with the Authority that EDBs continue to be subject to the transmission charges as there would be significant costs involved in making retailers subject to transmission charges" (p.5)

45 Investment efficiency: interaction between the TPM and the Commerce Commission’s role

The TPM should be aligned with the investment approval process
EPOC: "the Authority should aim to integrate transmission pricing with the transmission investment decision process and also with a market for generation capacity. An important aspect of this would be enabling the demand-side to bid in for their desired maximum demand" (p.13)

MEUG: "[It is necessary to align] any decisions to revise the TPM by the Authority with changes to the Capex IM by the Commerce Commission. At this stage the timing for both of these processes is conducive to considering good alignment" (p.2)

Investment approval process is focused on "public" and not "private" benefits
Trustpower (Vince Hawksworth Letter): The Authority "appears to be giving pre-eminent consideration to the ability of a TPM option to influence the Commerce Commission’s transmission expenditure approval processes even though that process is focussed on public (and not private) benefits." (p.1)

Authority is not responsible for investment efficiency in relation to transmission investment
NZAS: the Authority should assume that the Commerce Commission has done its job appropriately in setting efficient revenue. The Authority should not distort the TPM to compensate for any inefficiency by the Commerce Commission (p.12-13)
Also: Counties Power (p.2-3), Counties Power Consumer Trust (p.1), Pioneer (p.4), Trustpower (p.3)

Trustpower: The divide in responsibility is reflected in the current TPM guidelines and the MOU between the Commerce Commission and the Authority. It is supported by Professor Bushnell's view that transmission prices should not distort nodal price signals. It has also been recognised by Parliament (in that Part 4 specifically takes precedence on matters of transmission investment) (p.3).

Trustpower "as the first priority, steps must be taken to ensure that any differences between the short-run marginal cost (SRMC) and long-run marginal cost (LRMC) of transmission are minimised, before contemplating any further reform" (p.4)
Trustpower: "there are several reasons why nodal prices may not expose transmission LRMC, including lack of competition, lumpiness of investment, reliability standards set by regulators and inefficient demand-side SRMCs. In our view, the vehicle for the decision to approve transmission upgrades is the IPP, because it specifically sets the price-quality relationship and requires Transpower to expose and seek approval of all new grid investment projects ahead of time" (p.5)

Allocations based on "actual" rather than "expected" benefits do not align well to the investment approval process
Genesis (Castalia): "We also see a practical issue in that both DCC and SPD charges allocate the costs of assets based on past behaviour or actual use of the asset. Therefore, when new assets are commissioned, it is not clear how initial charges will be set. Tools such as flow tracing and SPD runs using actual wholesale market bids cannot be used initially to allocate costs because information will only be available ex-post. This highlights the trade-off between choosing a more ‘dynamic’ charge and one that can be calculated ex-ante." (p.22)

46 Investment efficiency: participation in the grid approval process

Participation in grid investment approval processes could be improved through the TPM
Marlborough Lines: "The existing assets, especially those pre 2004 are the result of historical decisions and are often quite different to what would be built today … where there was increased engagement in the decision making process" (p.6)

NZAS: "Improved price signals will encourage active engagement by transmission customers in decisions on transmission investments and its substitutes, in how revenue is determined, and stimulate continuing interest in efficient pricing" (p.15)
Also: MEUG (NZIER) (p.14)

There is likely not to be more participation in grid investment approval processes
Pioneer (p.3)

MEUG (NZIER) EDBs: already have strong incentives to participate in grid approval processes. It is questionable as to whether changes to the TPM will change these incentives. This question should be a key focus for the CBA." (p.26)

Trustpower (Creative): It is not clear beneficiary pays would promote effective user participation. (p.iv)

Transpower (CEG): Participants may not have the resources to engage with the investment process (p.32)

Transpower (CEG): "The ability of new participants to engage in the investment process in an informed way will also be influenced by the complexity of the TPM" (p.32)

Westpower: "The Authority is assuming that parties will see the incidence of charges being imposed and thus will understand that once existing assets are constrained due to increased use, they will need to fund the replacements. This assumes substantial understanding on the part of consumers that may not be present in reality…" (p.3)

Implementation issues
MEUG: More information on forecast costs and benefits will be required in the pre-investment decision making phase. Improvements to the Capex IM may be needed. (p.3)

Engagement will be based on self-interest
Counties Power: engagement would be based on self-interest, which likely would conflict with Transpower's investment drivers. This could lead to inefficient outcomes. (p. 13-14)
Also: Orion (p. 3), Trustpower (p.2, 7)

ENA: Lobbying will not increase the efficiency of the grid investment process. Parties with the most money would dominate the lobbying effect. (p.8)
Also Powerco (p.1-2, p.4-5)

Signals will not be strong enough or timely enough for better engagement
NZ Steel: "we are far from convinced the signals will be strong enough or timely given the long-term nature of investment decisions made by many consumers." (p.2)

Powerco: the Authority is attempting to engineer an incentive to act by modifying what is likely to be a fraction of one per cent of their [most participants] total costs" (p.1-2, p.4)

Participation (even if it is improved) will not have much effect
Fonterra: The "information asymmetry problem applies equally to users of the proposed investments and the allocation of greater transmission charges to users will not resolve this problem." (p.6)
Also: Orion (p.3), MEUG (NZIER) (p.7).

Orion: "Participants' private commercial perspectives may be relevant, but they are not necessarily determinative [for making efficient investment decisions]" (p.3)

TNT2: "the Authority continues to overestimate the influence that participants can have on regulators." (p.3)
Also: Molly Melhuish (p.3)

Trustpower (Vince Hawksworth Letter): The Authority "appears to be giving pre-eminent consideration to the ability of a TPM option to influence the Commerce Commission's transmission expenditure approval processes even though that process is focussed on public (and not private) benefits." (p.1)

The large investments have already been approved or have already occurred
Transpower (CEG): Price signals that would encourage participants to engage in the grid investment process are likely to be modest given that most of the significant investment has already occurred (p.15)
Also: Pioneer (p.2-3) West Coast Joint Submission (p.2), West Coast Electric Power Trust (p.2)

Participation may not improve without decision rights
TNT2: "In the absence of decision rights parties to deep connection have little they can do except for try to inefficiently avoid the charges. In our view, somewhat ironically, the Authority continues to overestimate the influence participants can have on regulators." (p.3)

47 Investment efficiency: general

Overall investment efficiency impact of the options is difficult to determine
Transpower (CEG): "the theoretical link between transmission pricing reform and superior investment outcomes is tenuous. Moreover, the complexity of the options that have been proposed makes any such relationship even less likely in these particular circumstances." (p.28)

Retrospective regulation is a disincentive to invest
Tai Tokerau Northland: "Retrospective regulation that send price signals after investment has been made (e.g. Marsden A and B) also acts as a disincentive to invest and therefore will further impact future investment." (p.4)

Retrospective regulation will limit the effect of pricing signals where assets are already built
MEUG (NZIER): Base case marginal cost signals are "Limited because virtually all costs are sunk. Addition of LRMC mechanism improves investment signals going forward but seems complicated." (p.14)

Increased charges will act as a disincentive for economic development in regions
Auckland Regional Chamber of Commerce: "The new approach will unequivocally stifle economic development especially for some New Zealand's poorer regions such as

Northland and the West Coast. These regions will experience a significant increase in their national grid charges should the EA's proposal be implemented." (p.1)

West Coast joint submission: "The proposals in the EA's Options Paper only serve to deliver a significant disincentive to economic development in this region" (p.2)
Also: West Coast Electric Power Trust (p.2), Westland Milk Products (p.4-5)

Options may create incentives to relocate away from some regions
EMA Northern: "The prospects of businesses wishing to relocate or establish new manufacturing businesses to regions such as Northland will be stifled should the Authority's proposal go ahead." (p.2-3)

Options may incentivise inefficient investment in DG
Westland Milk Products: "our use of high pressure steam boilers creates the opportunity to co-generate. While this has previously not been economic, the proposed TPM changes may significantly alter those calculations. This seems a perverse outcome" (p.5)

Westland Milk Products "the changes will significantly alter the investment calculations for Dryer 7; several years after we decided to build it in Hokitika (rather than Rolleston)" (p.6)

TLC: The incentives provided by the proposed changes will lead to incentivising LFC and holiday home customers to disconnect from the network by investing in PV and batteries (p.6)

Removing demand (peak) signals may lead to earlier investment than is efficient or remove an efficient signal to decommission older assets
NZ Steel: "We are concerned removing demand signals will ultimately lead to earlier than otherwise required investment… It is extremely important pricing signals are for the long term consistent with the time frame on which investment decisions are based" (p.2)

NZ Steel: "The paper talks of "further investment", but is light on the cost of maintaining and replacing existing assets. The question needs to be asked, that with demand side management would it be possible to decommission some older assets?" (p.3)

Trustpower: "a peak signal should be an enduring feature of any future TPM; and … once signals have been put in place they need to remain for a duration sufficient to maintain investment incentives" (p.26)

Trustpower: "even in a scenario in which demand growth appeared unlikely, we believe the option value that a peak charge provides is reason enough for it to be maintained" (p.26)

Reallocation of charges may shorten the lifespan of assets/cause asset strandings
NZCID: "Regulatory changes, such as those to the TPM, which impact the spatial allocation of charges to fixed assets, will result in shorter lifespans for those assets negatively impacted by new charges" (p.2)

TLC: The incentives provided by the proposed changes will lead to providing an incentive to bypass the transmission system to avoid connection and deeper connections charges resulting in stranded assets (p.6)

Options could incentivise customers connected to EDBs to remove a single meter of a higher class and install multiple meters of a lower class
TLC (p.6)

Locationally targeted charges could lead to no infrastructure being built
EMA Northern "If you were to apply the Authority's logic for the shared transmission grid to other essential infrastructure then no infrastructure development would occur in New Zealand." (p.2)

Options could inefficiently signal additional transmission costs
Nova: Taranaki north of Stratford assets "signalling additional transmission costs for new generation that do not actually exist." (p.2)

Base option may have diluted economic signals
MEUG (NZIER): The options are only partly cost-reflective because of the tiered nature of mechanisms in base case dilutes economic cost signals (p.14)

Base option has limited transparency, which is not market-like and reduces investment efficiency
MEUG (NZIER): Transparency is required for investment efficiency. Transparency is limited in the base case "because mechanisms are mainly administrative arrangements which allocate regulated costs that flow from a centrally planned grid". This reduces efficient investment. (p.14)

Base option may have limited subsidies, promoting efficient investment
MEUG (NZIER): Subsidies reduce investment efficiency. The base option has minimal subsidies "but only to the extent that an individual mechanism does not inhibit economic signals." (p.14)

It is unclear whether the base option is adaptive and thus it is difficult to measure the impact of this on investment efficiency
MEUG (NZIER): Adaption to change is required for investment efficiency. The adaptivity of the base option "Depends on the approaches used to update historical data and analysis for each charging mechanism. Addition of SPD mechanism is an improvement." (p.14)

The base option is less distortionary than the status quo, which should positively impact investment efficiency compared to the status quo
MEUG (NZIER): Distortions reduce investment efficiency. The Base case is "Better than status quo TPM – locational and economic signals are improved but unclear to what extent. Embeds distortions by using data from recent past" (p.14)

Effect on investment certainty
KCE: small changes in assumptions have a large effect on the allocation of charges, increasing costs. (p. 2)

NZAS: "Predictability is enhanced if regulatory decision-making is based on clear and consistently applied rules. A decision by the Authority to deviate from the adoption of efficient prices would undermine confidence in the regulatory process" (p.41)

NZCID: "The cost of uncertainty must be acknowledged… Capital markets price risk. The terms under which large electricity companies are able to access finance are impacted by regulatory risk, such as changes to the methodology governing national transmission charging… In addition to a higher cost of debt, risk also increases costs to electricity infrastructure providers, and in turn consumers, by reducing the lifetime value of fixed assets." (p.2)

NZWEA: "This submission focuses on certainty and regulatory risk, particularly around distributed generation and the avoided cost of transmission." (p.1)

Tai Tokerau Northland: "creates a level of uncertainty which makes the planning and investing in long term difficult if not impossible" (p.3)
Also: Westland Milk products (p.6)

Strong signals appear suddenly
Westpower: "The proposed TPM…results in extremely strong marginal price signals appearing suddenly… no one party may be able to fund the level of investment required" (p.3)

48 Operational efficiency: inefficient avoidance of charges

Parties will alter their behaviour to avoid charges
Counties Power (p.10), Electra (p.2), Genesis (Castalia) (p.18), PwC (p.10), Rangitihi (p.2), Top Energy (p.4), Top Energy Consumer Trust (p.2), Te Houtaewa Maori Trust (p.1), Vision Far North (p.2), Waiharara Primary School (p.2), Westpower (p.5)

Vector: "Grid distortions will occur as users make inefficient locational or consumption decisions based on the desire to avoid higher transmission fees." (p.2)
Also: IEGA (p.2), Pioneer (p.2)

Counties Power Consumer Trust: Light industrials will be incentivised to by-pass Counties distribution network and connect directly to the grid (p.2)

Inefficient incentive to avoid or by-pass assets, leading to inefficient operation of the grid/stranding/decommissioning
Counties Power (p.10) Electra (p.2), Genesis (Castalia) (p.18), Rangitihi (p.2), Te Houtaewa Maori Trust (p.1), Top Energy (p.4), Top Energy Consumer Trust (p.2), Vision Far North (p.2), Westpower (p.5), Waiharara Primary School (p.2)

PwC: "The best example of this relates to the west coast of the South Island where capacity was installed for load that has now left the region" (p.8)

Inefficient incentive to create distributed generation

Waiharara Primary School: "[T]he proposals have the potential to encourage off-grid development of distributed electricity diminishing the value of existing infrastructure and lessening the load on our local lines network resulting in less use/demand and hence a loss of value of the network which is "owned" by all consumers" (p.1)

Also: Rangitihi (p.1), Te Houtaewa Maori Trust (p.1); Te Tai Tokerau (p.4) Vision Far North (p.1)

The options may cause regional effects including businesses avoiding regions and existing parties opposing new customers in a region (even if there is spare capacity)
ENA (p.9), PwC (p.8), Genesis (Castalia) (p.iii), IEGA (ASEC) (p.3), NZ Energy (p.3), Te Houtaewa Maori Trust (p.1), Tai Tokerau Northland (p.1), Westpower (p.5)

Waiharara Primary School: "Any increases in electricity distribution charges as proposed by you will have the potential to make their operation uneconomic with a closure and devastating effects on the local economy" (p.2)

Also: Rangitihi (p.2), Te Houtaewa Maori Trust (p.2), Tai Tokerau Northland (p.3), Vision Far North (p. 2),

NZ Energy: "The problem has the potential to spiral out of control" (p.3)

Westland Milk Products: The proposal will lead to exits in the West Coast region….[and will cause] random fluctuations in our charges which are entirely unrelated to our own electricity use and will be difficult to predict or mitigate" (p.5)

Westland Milk Products: This would penalises those few remaining large users for their success at being "last men standing" (p.5-6)
Also: EPOC (p.5), West Coast joint submission (p.2), West Coast Electric Power Trust (p.1)

Oversignalling by combining capital and congestion costs
Trustpower: "additional capital charges on top of congestion costs implicit in nodal prices could lead to inefficient under-utilisation of resources." (p.18)

Trustpower (Bushnell): "the very purpose of LMP is to properly capture in real-time the shadow costs of all relevant network constraints. Transmission investment decisions should in turn ideally be based upon the stream of values provided by that asset. If investments are being driven by a constraint, it should be represented in the LMPs." (p.7)

49 Operational efficiency: peak load management and demand response

The options will undesirably reduce incentives to control load at peak times

Counties Power Consumer Trust (p.2), Genesis (Castalia) (p.29) IEGA (ASEC report) (p.11) KCE (p.2); Pioneer (p.2)

Bryan Leyland: this will lead to higher prices and ultimately new transmission reinforcement." (p.1)

Electra: "Electra will have no incentives to manage load and real peaks will increase faster than the pricing mechanism can keep up with." (p.2)
Also: ASEC for Electra/KCE (p.2)

NZ Steel: "We do need pricing signals to which we can react to ensure the best value to business operations. The alternative to achieve cost savings may involve 'turning-off'" (p.2)

PwC: "[Moving] away from a peak-based charging regime for allocating transmission charges will make it harder for distributors to justify investments in load control systems" (p.11)
Also: ASEC for Electra/KCE (p.12)

Pioneer: The options "are designed to discourage any attempt to manage peak demand…the only driver of the need for new transmission capacity…[This] penalise[s] DG" (p.2)

TLC: The incentives provided by the proposed changes will reduce incentives to actively control load despite considerable investments in load control assets. (p.6)

Trustpower: "under application A, the base option and the base option + SPD provide no incentives for peak load management akin to the existing RCPD signals. Even in the base option + LRMC, the signals would only be localised and would operate in a significantly different manner to the existing RCPD signal…We believe there is a strong risk of unintended consequences of significantly diluting the strength of existing peak demand signals. At the very least, peak demand would increase at a faster rate than it would otherwise" (p.26)

Authority should consider retaining an RCPD type component
ENA (p.12) Nova (p.3) NZ Steel (p.2) Powerco (p.8), Transpower (p.6)

Counties Power: There is still a requirement to send price signals because there is still congestion and it takes a decade to build peak demand control capability (p.17)

KCE: Charges should be allocated to load based on AMD or RCPD (p.2)

Orion: For residual allocation, ADMD is more consistent and transmission must be built to support ADMD. "RCPD is one version of this, but if there are real issues with creating incentives for inefficient avoidance, regional shares of total NZ CPD could be used." (p.8)

PowerNet: The Authority could consider RCPD with regional pricing differences based on Transpower's existing RCPD areas (i.e. a regional postage stamp approach)." (p.4)

TNT2: "It is not clear to us why there needs to be such a dramatic change in the residual charge. RCPD in its current form may have some incorrect incentives as a price. However, overall it seems to meet the Authority's objectives. It is substantially unavoidable and it is relatively broad based. Some major users are probably sufficiently price sensitive, like generators, and therefore the RCPD charge may lead to unacceptable static inefficiency in some cases." (p.4)

TLC: Possible modification to the existing TPM

- connection charges remain unchanged;
- stranded and sub-optimal assets would be identified and the return on assets would be recovered nationally via an RCPD charge…;
- the permitted return on productive assets by region (located in a region or used for a region) would be recovered via a region specific RCPD charge.
- The benefits of these changes would be:
    - a transparent methodology that the industry is familiar with;
    - a methodology that could be explained to consumers;
    - to address imbalances between assets and revenue by region;
    - to remove the burden of a stranded asset from that region;
    - to continue to encourage demand management." (p.8)

Trustpower: RCPD charging does apply charges to inelastic load and is thereby efficient to that extent. It has proven itself to be practical, transparent and enduring, and has widespread support across the industry. It defers transmission investment and gives price signals to distributors, who do not see nodal price signals. (p.26)

Trustpower: "there is a significant risk of unintended consequences inherent in any move away from New Zealand's long-standing peak demand charging regime. In the interests of practicability, stability and transparency, and continuity with the existing regime, in our view the Authority should consider other allocation methods for the residual, such as coincident peak or anytime maximum demand charging. This would ensure that customers are treated consistently regardless of location, connection or size" (p.19)

Transpower (CEG): the existing RCPD charge provides a forward-looking price signal. (p.16)

Unison: "we believe that the RCPD-type calculation is strongly preferable; or as an alternative evaluate an alternative charging approach where fixed charges form part of the calculation" (p.6, 14)

The move to 100 peaks for RCPD could have adverse effects
Westland Milk Products (p.7)

50 Efficiency: reallocating the charges on existing investments

Where charges are not correlated to benefits there is a strong case for reallocation
Unison: "There is also a strong argument to support a change to the TPM to shift charges away from parties who do not benefit from these investments. The test is which option is less unfair on parties and/or to consider transition options which gradually introduce changes over time" (p.7)

Maintaining inefficient charges on existing assets can preserve inefficiencies
Meridian: "It is not reasonable to argue that the current TPM must continue in relation to past investments in order to protect the reasonable expectations of investors to avoid chilling investment in the future. Rather, Application B would simply protect a particular interest group ..." (p.12)

NZAS: "If a revised TPM were applied only to new assets, the bulk of transmission revenue would continue to be recovered in a way inconsistent with promoting economic efficiency." (p.39)

Do not agree with the reallocation of the costs of existing investments
Counties Power (p.9), ENA (p.10), Genesis (p.10), MRP (p.1), Northland (p.3), Nova (p.1), Pioneer (p.2), Powerco (p.2,5), PwC (p.5), Refining NZ (p.2), Tai Tokerau NZCID (p.3), Te Houtaewa Maori Trust (p.1), Top Energy (p.8), Top Energy (p.8), Top Energy Consumer Trust (p.3), Vision Far North (p.1), West Coast Electric Power Trust (p.3), West Coast joint submission (p.3), Westpower (p.2)

Reallocating the costs of existing investments would not create efficiencies
Counties Power: "The EA's Application A proposals are seeking dynamic efficiencies for investment decisions already made and where costs cannot easily be avoided." (p.9)

Powerco: reallocating the cost of existing investments would be inefficient (p.2, p.5)
Also: ENA (p.9) PwC (p.5), Top Energy (p.8), Westpower (p.2), Transpower (CEG) (p.15), Vector (CLEX) (p.4) EMA Northern (p.3)

Parties may have made other choices if charges had been different/if given the choice
Transpower (CEG): The assets to which deeper connection and AoB charges are applied may be larger and more expensive than would have been the case if the parties knew they would need to pay (p.3)
Also: Pioneer (p.5), Genesis (Castalia) (p.14)

Reallocating the costs of existing investments would not be good practice
ENA: It is poor regulatory practice to implement retrospective charges. (p.12)
Also: Rangitihi (p.1), PwC (p6), Tai Tokerau Northland (p.1), Waiharara Primary School (p.1), Westland Milk Products (p.6), Westpower (p.9)

MRP: "Mighty River Power has consistently argued any changes to the TPM should be applied prospectively…consistent with the Authority's statutory objective of delivering the long term benefit for consumers" (p.1)
Also: Pioneer (p.2)

Genesis: "the Authority…should be more focused on the structures that enable a competitive electricity market…that is the wholesale and retail markets – rather than regulating prices to reallocate historical decisions amongst consumer groups. We suggest other regulators, such as the Commerce Commission, are better placed to consider the broader socio-economic impacts of regulated prices on consumers." (p.5)

Genesis: "If the Authority still wishes to apply new TPM charges retrospectively to historical asset decisions, it must clearly articulate its justification." (p.10)

Reallocation of costs of existing assets will create an uncertain investment environment and potentially change past business cases
PwC: The reallocation of sunk costs "may raise concerns in the minds of future investors that changes to the allocation of sunk costs will also be made in future" (p.6)

Trustpower: "Retrospective application of prices is inconsistent with the expectations at the time of investment. For a regulator to seek to determine prices based on historical decisions creates uncertainty, lacks transparency and undermines trust." (p.13)

West Coast joint submission: "the retrospective nature of the proposed change creates uncertainty, which is bad for economic development (p.3)
Also: West Coast Electric Power Trust (p.3); Refining NZ (p.2)

Broad-based charges for existing assets are efficient
Vector: "sunk cost recovery will always have an element of inefficiency but the most efficient method is a postage-stamp charge levied across the widest base possible." (p.2)
Also: AECT (p.2)

Vector: "by applying such a charge for all transmission costs (except connection charges) across generators as well as consumers, delivered electricity (retail) prices could fall by between 2% and 3%" (p.2)

Trustpower: "the IPP planning process, in conjunction with efficient nodal prices, is all that is required to signal the long-run costs of new transmission investment. It follows that the role of the TPM is therefore to allocate the sunk transmission costs after they have been approved, via an efficient cost-recovery mechanism" (p.5)

Willingness to pay at the outset of an investment is an important consideration
BusinessNZ: When thinking about a cost recovery scheme that is to be imposed on an identified group of beneficiaries for a particular asset after commissioning then an allocation after the fact should reasonably not charge more to any sub-group than they could objectively have been expected to have been willing to pay at the outset. In our view, this would get close to the base option + application A (p. 5-6)

51 Durability of the options

Factors that are required for durability
Business NZ: Coherent and rational decisions (p.6)

Business NZ: Certainty of returns (p.6)

Marlborough Lines: Accepted by parties as being fair (p.4)

Marlborough Lines: transparency (p.4)
Also: Meridian (p.10)

Meridian: Costs must align to benefits/congestion over time (p.10)

Meridian: Unreasonable outcomes avoided (p.3-4)

Meridian: Minimise distortions in downstream markets (p.10)

Powerco: Fewer modelling assumptions/charge less sensitive to assumptions (p.4)
Also: Top Energy (p.9), Top Energy Consumer Trust (p.2-3), Tai Tokerau Northland (p.4)

Westpower: Less complexity (p.7)
Also: Powerco (p.2, PwC (p.6), IEGA (ASEC) (p.18), Marlborough Lines (p3-4)

Principled approach is required for durability
Contact: "Without a principled approach, any future change to the TPM will not be durable. Not only will the Authority be lobbied around new investments but there may be perverse outcomes where parties seek to avoid charges. Any further papers should explain how the Authority intends to deal with changes to load or generation in the future." (p.1)

Meridian: Costs should be allocated on a principled basis and grounded in robust factual analysis which minimises subjective decision-making. (p.10)

Options not durable
Marlborough Lines: "We do not agree that the options proposed would be durable." (p.3)

Political durability as an objective would undermine the Authority's statutory objective
NZAS: "If the Authority were to give consideration to whether an efficient pricing regime would be "politically durable", this would undermine … the intention of the Electricity Act [that] was to improve the governance arrangements for the electricity industry by establishing an independent Authority with a clear and narrow statutory purpose" (p.15)

NZAS: "The industry should be able to rely on the regulatory framework and processes, not just a particular version of the TPM, for regulatory credibility and hence durability." (p.16)

The options will create incentives to lobby and dispute

Counties Power: Under deeper connection Counties "would be required to seek legal action to remedy a non-negotiated outcome." (p.15)

Counties Power Consumer Trust: "The new complex charging arrangements will reduce the efficiencies gained from Transpower's central transmission planning and be subject to lengthy dispute" (p.1)

ENA: There will be lobbying to change the deeper connection regime (p.10)

Orion: "There may at least be some contest as to whether those benefits were correctly assessed and/or have actually materialised." (p.7)

Powerco: "The incentive to engage in ongoing lobbying to change the defined area of benefit would be likely to undermine the durability of the method [mainly large generators and direct connects]" (p.5)

PwC: "the new TPM looks likely to be significantly more susceptible to lobbying and dispute than the status quo" (p.5)

The Authority has not discouraged lobbying in the past which has promoted lobbying

Transpower (CEG): "Changes in the TPM that have only modest efficiency implications can still give rise to large transfers of wealth between industry participants. It is therefore only natural that profit maximising firms have lobbied continuously to have the methodology changed in their favour. The willingness of the EA and its predecessor to continue to entertain the notion of reforming the TPM is also likely to have contributed significantly to this conduct." (p.34)

Deeper connection charge conflicts with Transpower's objectives and will reduce durability

Counties Power: Deeper connection charge will have less durability than the existing postage stamp charges because of the conflict with the existing aims [reliability] of Transpower. (p.14)

Bespoke adjustments will be required under the options which can undermine durability

Powerco: "the different models that might potentially be used and the bespoke adjustments that appear to be needed to avoid undesirable outcomes (such as the incentive created by the "deeper connection" method for EDBs not to amalgamate) are likely to undermine the durability of the proposed methods." (p.2)

PwC: "[The requirement for judgement] will …impede the efficient operation of the electricity industry as effort and resources will be focused on debating such judgements rather than on more productive activities." (p.7)

Authority's intended reconsideration of LRMC, AoB and deeper connection every five years could undermine durability
Pioneer: "durability of the proposed charges is being substantially limited by the plan to modify the LRMC, Area of Benefit and Deep Connection charges at 5 yearly intervals…this means the signals about the cost of transmission assets will alter every five years…" (p.5)
Also: IEGA (ASEC) (p.18)

Westland Milk Products: "the outcomes will be difficult and costly to predict for both users and the EA; parties will seek (and find) loop-holes to exploit; and the TPM will require more regular review and updating. The current TPM is less complex" (p.5)

TPM development through Transpower operational reviews can promote durability
MRP: "We do not agree that [for Transpower's operational review] it is unlikely to be feasible to develop mechanistic rules to determine when and how the TPM should be reviewed or price signals should change. Even if this were the case, the same limitation would apply to the Authority's proposal which requires several of the new charge elements to be re-opened periodically" (p.5)

52 Complexity of the options

The options are too complex
Electra (p.2), KCE (p.1), MRP (p.1), Nova (p.1), Pioneer (p.1), Powerco (p.1), TNT2 (p.1) Top Energy Consumer Trust (p.2) Top Energy (p.9), TLC (p.4)

AECT: The proposals are "radical, complex, and untested" (p.1)

Contact: "the addition of LRMC and SPD both appear to add significant uncertainty and complexity to the methodology without providing the requisite benefits or efficiency gains" (p.2)

ENA: "The TPM is at risk of being made too complex, even without the addition of the particularly complex SPD method." (p.11)

Kawatiri Energy: "The complexities around the Area of benefit and Deeper connection charges, particularly in our area which is facing huge increases in transmission charges will create in-efficiencies" (p.1)

Marlborough Lines: "Both alternatives presented in the paper are very complex". Do not agree with the use of information and analytical frameworks for a crucial purpose that is so very different from that which they were designed or provided for. (p.4)

NZCID: "emphasise the value of simplicity…the complexity of the TPM has now reached such a point as to reduce the transparency of the electricity market… Risks that cannot be clearly understood and mitigated, are priced accordingly" (p.2)

PwC: "the complexity of the charges and their interactions makes it difficult to determine in advance exactly how the different parties will respond to the proposed TPM or whether those responses will be efficient." (p.7)

Refining NZ: "Any revision should stand the basic test of being able to be understood by economists and non-economists alike" (p.3)

TLC: "a system so complex, even industry participants struggle to understand" (p.4)
Buller "more complex arrangements do not necessarily guarantee more efficient outcomes or a fairer allocation of transmission costs" (p.1)

Complexity should have a clear purpose
Genesis: "the current electricity wholesale market is a good example of where complexity has a clear purpose" (p.9)

Complexity will affect the ability of participants to engage in the investment approval process
Transpower (CEG): "The ability of new participants to engage in the investment process in an informed way will also be influenced by the complexity of the TPM" (p.32) (p.61)

Complexity will make it difficult for parties to forecast their charges
Genesis (p.8), Pioneer (p.4)

Refining NZ: "We express concern with the complexity and variability of the models proposed". Refining NZ had to hire economic consultants to understand charges, whose analysis had to be redone following revised estimates. "Large swings in charges based on small tweaks to secondary modelling are a problem" (p.3)

Trustpower: "The Authority has proposed a pricing regime of breath-taking and bewildering complexity… The individual methods are complex individually and are then pancaked into a final price which users will find impossible to understand, model and respond to." (p.32)

Complexity will create significant implementation costs
Transpower: "options should be understandable and implementable by (i) Transpower as TPM administrator and (ii) load and generation customers who respond to price signals… base option that risks being so complex as to be not understandable…" (p. 61)

Genesis: "Complex regulatory interventions create significant implementation costs…building false economies for expertise that is, frankly, unnecessary" (p.2, p.9)

Complexity can create barrier to entry
Vector: "While transmission pricing is a complex subject, there is a trade-off between seeking perfection and introducing unnecessary complexity as this can create barriers to entry for new players. For example Meridian's preference for the base option acknowledges that a combination of connection, deeper connection, AoB, and SPD or LRMC charges, and the residual, would create unnecessary complexity, uncertainty and cost on existing parties and new entrants to the electricity sector" (p.3-4)

Options have too many administrative variables
Buller Electricity (p.14), Fonterra (p.5), Marlborough Lines (p.4) Top Energy (p.9), Trustpower (Vince Hawksworth Letter) (p.1)

Note: Trustpower made a long list of variables/administrative decisions in the TPM review.

Genesis: "We suggest the Authority should focus on minimising the number of elements within its options… enables the benefits to be maximised and decreases the cost of implementation" (p.5)

Meridian: "The overall methodology should minimise discretion (and hence lobbying and potential litigation)…(p.5)

Charge: AoB with minimal discretion
Fonterra: "The Working Paper notes that identifying beneficiaries under the AoB charge can require judgement. Fonterra encourages the EA to consider how a revised TPM could minimise the use of discretion." (p.5)

Paper is too complex
NZ Energy: "a very complex and confusing document." (p.2)

Also: Bryan Leyland (p.1), AD Harwood (p.1)

53 Pricing effects

Difficulty in determining the pricing effects of the options
AD Harwood Limited: "We cannot determine what extent our business will be affected if these changes are implemented." "Has the EA put a business like ours into their financial model?" "we have recently seen a transfer of transmission assets into the local Network Company's ownership. How does this affect us." (p.1).

EMA Northern: "while the Authority suggests this proposal will increase residential bills in the Auckland area by 4.5%, it is silent on who picks up the rest of the increased bill. We can only take the view that business will be expected to carry the additional cost impost" (p.2)

Kawatiri Energy: "It is near impossible to determine what extent our business will be affected over and above the loss of ACOT." (p.1) [also see section on ACOT]

Genesis: "We are pleased to see the Authority has assessed the impact of the proposed changes to the TPM on residential consumers." (p.3)

There will be a wealth transfer
KCE: The proposals create an enormous wealth transfer (p.1)

Electra: The deeper connection, residual combination will create significant wealth transfers from year to year (p.2)

Marlborough Lines: "We are very concerned that the proposed mechanism for allocating the significant residual charges is an inequitable and unjustified transfer of wealth from ENBs (and ultimately their consumers) to directly connected major users" (p.9)

There will be an undesirable transfer of charges to certain regions

There will be an undesirable transfer of charges to the West Coast
AECT (p.1), Molly Melhuish (p.3), West Coast Refining NZ (p.2), Westland Milk Products (p.3)

There will be an undesirable transfer of charges to Northland
AECT (p.1), Counties Power (p.11), EMA Northern, Northpower (p.1), Grant Keymer (p.1), Refining NZ (p.2), Top Energy (p.4) Te Houtaewa Maori Trust (p.2), Te Tai Tokerau (p. 1-2), Rangitihi (p.2), Top Energy Consumer Trust (p.2), Vision Far North (p. 2), Waiharara Primary School (p.2)

There will be an undesirable transfer of charges to Auckland
Auckland Regional Chamber of Commerce (p.1), AECT (p.1)

There will be an undesirable transfer of charges to low-socio economic areas/regional New Zealand generally
Counties Power Consumer Trust (p.1) Refining NZ (p.2)

Regional wealth transfers are undesirable because they are not matched to benefits

Northpower: "Northpower has not observed any material increase in retail competition due to cheaper wholesale prices, and does not consider that these benefits will ever offset the increase in transmission charges that consumers are likely to encounter under the proposed TPM options." (p.2)

Regional wealth transfers are undesirable because they affect durability
Pioneer: "the significant impact … on the Far North and West Coast…brings into question the durability of the proposed options." (p.5)
Also: Genesis (p.4)

Regional wealth transfers are undesirable because they will have a negative effect on economic development

Auckland Chamber of Commerce: "The new approach will unequivocally stifle economic development especially for some New Zealand's poorer regions such as Northland and the West Coast." (p.1)

Counties Power: "any economic modelling must consider future revenue and demand growth…The growth in the Upper North Island has driven the investment and future growth will drive additional transmission revenue….This needs to be determined" (p.11)

EMA Northern: The proposal will increasing costs for businesses, increasing Northland grid charges by 172% and working against government initiatives to encourage business in Northland.

Also: Refining NZ (in relation to regional New Zealand generally) (p.2), Te Tai Tokerau (p. 1-2),

Westland Milk Products: The proposal ... will lead to the exit of customers from certain regions. This is not consistent with the efficient operation of the electricity industry. Low demand has already led to the exit of industrials, and further increases will need to be paid by a diminishing pool of consumers (p.3).
Also: Tai Tokerau Northland (p.2), Top Energy (p.4), Top Energy Consumer Trust (p.2),

Regional wealth transfers are undesirable because they place an unfair burden on those least able to pay
Ross Clark (p.2)

Waiharara Primary School: "We cannot agree that a study as important as this should ignore downstream effects on all consumers especially where changes will inevitably result in many families and small businesses in our area will suffer under a regime of increased transmission prices." (p.1)
Also: Vision Far North (p.2), Rangitihi (p.2), Te Houtaewa Maori Trust (p.2), Mr Peters (p.1)

Top Energy Consumer Trust: "The quantum of $259 per year per ICP, equating to $21.56/month is a material impact on a lot of families' incomes in the Far North" (p.1)

Regional wealth transfers would negatively affect social outcomes
Northpower: The changes would have a "material adverse impact on the Northland community social and economic well-being." (p.1)

Refining NZ: "We suggest that that type of thinking and the overall societal cost impact on regions be taken into account" [Electricity cost for heating and light is important for early childhood health and education] (p.2)

Genesis: "the paper justifies these changes [price increases to residential customers] as being economically rational, it takes no account of the impact this increase has on individual consumers" (p.1)
Refining NZ: The National Infrastructure Advisory Board and National Infrastructure Unit, "Infrastructure 2013: - National State of Infrastructure Report", draft vision states that infrastructure investment should be based on "a firm understanding of the levels-of-service needed to underpin sustainable growth and social equity" (p.2)

There will be a desirable transfer of charges away from Southland, which will boost business in the region
Export Southland (p.2), EIS (p.2), Lewis Windows (p.2), McIntyre Dick and Partners (p.2), Preston Russell Law (p.1) Southland Manufacturers Trust (p.2), StabiCraft (p.2) Invercargill Licensing Trust (p.2), Southland region (p.1), Venture Southland (p.1)

Southern Institute of Technology: It is difficult "to have to operate within a funding regime which rewards a larger Northern population while being over charged to subsidise their electricity costs." (p.1)

Southland region "Auckland alone, with a population of 1.42 million and a population growth rate of 8.5% has the ability to fund current and ongoing expansion to meet future network needs." (p.6), Also: Venture Southland (p.6), Ms Dowie (p. 3).

The efficiency impacts of wealth transfers

Buller: the proposals would lead to price shocks without efficiency gains (p.13)

Buller: "Most EDBs will not have an equivalent or similar charge to the new charges proposed by the EA. However, it is likely that any equivalent will be a proxy locational charge that affects the rural and remote consumers the most…Locational cost reflectivity for BEL's sparsely populated network region may deliver significant price shocks to rural consumers—but without delivering any efficiency benefits. (p.9)

Buller: Strongly submit that the Authority must provide clarity on the downstream impacts of the proposed TPM on distribution pricing. In particular, locational cost reflectivity in distribution pricing may deliver price shocks without efficiency benefits. (p.9)

MRP: "Our primary concern is with the large price increases… arises solely under an application of the proposed methodology to historic transmission assets." (p.1)

Pioneer "The structure of transmission charges is going to have no impact on the total size of the pie" (p.2)

Amount of wealth transfer

Counties Power Consumer Trust: NZ Steel's charges reduce by 81% while Counties Power's transmission charges increase by 75%, although they are both in the same region. However, NZ Steel's maximum annual electricity demand is 15% greater than Counties Power. (p.2)

Vector (CLEX report): "while generators would not pass-through fixed transmission charges, line companies' charges are passed through to retailers who in turn include those charges in the variable charge to final users. Thus, the EA's proposal of applying postage stamp charges only to loads is distortionary and would lead to higher retail prices" (p.6)

Transpower: Modelled the allocations to the four load regions, generators, and direct connects. Transpower concluded that "The biggest driver of the swing against the status quo appeared to be the residual charge. Moving to AMD based charge across the board, rather than AMD for direct connects and ICP capacity for EDBs, moderates the strength of the charge increase toward North Island EDBs." (p.14)

Westland Milk Products: "Westland's total electricity costs will increase to $9.0 million per annum, compared to a current $6.7 million. This is a very substantial increase of $2.3 million (+34%)." (p.1-3)

Westpower: "280% increase [in Westpower's charges] …after allowing for the countervailing effect of a reduction in ACOT…the net impact … is still of the order of 180%" (p.2)
Also: Westland Milk Products (p.4)

54 Avoided cost of transmission

DG competes with transmission capacity and should be treated accordingly
KCE: The proposals will be unfair to load management and embedded generation in the capacity management market, in which they must compete with Transpower, which has guaranteed revenue and would have regulatory bias under the proposals (p.1)
Also: Nova (p.4)

IEGA: distributed generation provides the only competition to transmission. Given pricing reforms, it is necessary for there to be a long-term payment to local generation for the capacity it provides, based on LRAC. Application A would eliminate these payments (p.2)
Also: IEGA (ASEC report) (p.4-8), KCE (p.1), Nova (p.4), NZ Energy (p.3), Mainpower (p.1)

IEGA (ASEC report): "one objection that the Authority has raised against the current ACOT regime is that in allowing the LRAC of transmission to also be paid to distributed generation, the total cost to consumers increases. In the short term occurs as a consequence of not allowing the transmission owner to be exposed to competition; but over the long term the regime enables competition between local generation and transmission that should result in lower costs to consumers. If the transmission owner was exposed to competition then payment of ACOT would not result in any increase in cost to consumers. But the transmission owner is not exposed to asset stranding, so these costs must ultimately be borne by the consumer paying for transmission assets that may not be required, albeit at a lower cost of capital." (p.9)

Impact of the Authority's options on ACOT payments
Top Energy "residual, area of benefit and deeper connection charges would most likely mean that the operation of distributed generation will not lead to any ACOT."(p.4)

Also: Top Energy Consumer Trust (p.3)

Westpower: Westpower's Amethyst Hydro plant is likely to lose a lot of ACOT revenue. Amethyst Hydro produces approximately one quarter of the distributed generation on Westpower's network. (p.6)

NZ Energy: "These [ACOT] payments make up over 12% of our revenue and a very significant amount of our gross profit… it is also critical for the long term operation of our business" (p.1)

Nova: ACOT payments will reduce because of the option working paper's capacity allocations. (p.3)

ASEC for Electra/KCE: "Given current approaches to calculating a credit for the Avoided Cost of Transmission (ACOT), …[capacity rather than peak charging] will make it difficult to compensate the capacity provided by embedded and distributed generation." (p.4)

IEGA (ASEC report): "the Authority's proposals do not entirely preclude the calculation of ACOT payments equal to the LRAC of local transmission. However, this is only a viable option if (a) Part 6 of the Code, which governs a number of issues related to embedded generation, provides for such payments, (b) there is an accepted methodology for calculating the relevant payments, and (c) the Commerce Commission agrees that these payments calculated in this yet-to-be specified methodology can be recovered as pass-through costs by Electricity Distribution Businesses." (p.9)

IEGA (ASEC report): For SPD it "appears that benefits would be calculated using the net demand recorded during each capacity measurement period. This may provide a basis for calculating ACOT, but this again would require SPD runs to calculate the charges with and without a particular generation plant." (p.23)

A requirement to assess the impacts of a change to TPM on ACOT
NZ Energy: "It may well be that the Part 6 review re-affirms that DG payments are justified and that the current method of using ACOT is the most efficient, fair and reasonable means of determining payments to DGs. Why on earth would you then want to go ahead and alter the TPM ahead of such a review only to have it reversed in part?" (p.3)

Unison: "Any TPM change would need to be considered alongside the review of ACOT to ensure the impacts are fully considered" (p.16)

Also: KCE (p.1), Pioneer (p.8)

Pioneer: "The Authority is also yet to address the unintended consequences of any change to the TPM on distribution pricing or the recognition in Part 6 of the Code of the value of distributed generation to the entire electricity system." (p.6)

Trustpower: "the impact of the [TPM] change has been understated in the Consultation paper because it does not specifically take into account the effects … to distributed generation plant, which receives avoided cost of transmission (ACOT) payments" (p.27)

AD Harwood Limited: "It is impossible to consider the proposed changes to the TPM without understanding what the Authority might be proposing for avoided-cost-of-transmission payments and distribution charges" (p.2)
Also: Mainpower (p.1), KCE (p1)

Support for an ACOT review or agreement that ACOT is inefficient
Unison: "Unison welcomes the upcoming review of the current ACOT payments as they are currently inefficient" (p.23)
Also: Buller (p.1), Contact (p.5)

Contact: "Contact is not concerned with whether this is dealt with through the TPM consultation or distribution pricing principles paper, our focus is seeing the issue addressed" (p.5)

Suggestions for revised ACOT arrangements
Nova proposes "ACOT payments should:

- continue for a period of twenty years from the date of investment in the generation capacity, i.e.
    - A power station that was acquired from a third party 15 years ago should get 5 more years of payments, and
    - A power station that was expanded 5 years ago should get 15 years of payments relating to that expansion, etc.
- be added to Transpower's Maximum Allowable Revenue (MAR); with Transpower taking over responsibility for making the ACOT payments.

Under this proposed arrangement, embedded generation can be treated as a true alternative to transmission… a mechanism for paying for that, just as it does for demand response… New ACOT payments would only arise if and when Transpower contracted the generator to supply generation as a replacement for a transmission investment…The Commerce Commission would also then be in a position to consider the relative merits of new transmission investment proposals against all of the viable economic alternatives when Transpower proposes grid upgrades." (p.4)

ACOT payments should be preserved for investment certainty
PwC: "many parties have invested in generation on the basis of the current regulatory framework and with an expectation that would continue." (p.13)
Also: Westpower (p.6), IEGA (p.3), AD Harwood Limited (p.1), Mainpower (p.1), KCE (p.1) Kawatiri Energy (p.1)

Westpower: "Retrospective removal … makes it less likely Westpower or others will … make further investments in the industry due to the risk that a future regulatory U-turn could jeopardise the recovery of sunk costs" (p.6)

Wealth being transferred away from DGs
Trustpower: "A change to ACOT payments will result in a substantial transfer of wealth from existing investors in distributed generators to other participants, and increase the level of regulatory risk" (p.27)

ACOT reduces transmission costs
TLC: "upgrades of the Hangatiki substation transformers, at a cost of many millions of dollars, have been delayed due to the presence of embedded generation." (p.8)

AD Harwood Limited: in the half of the South Island (p.2)
Kawatiri Energy: at Westport, and in the top half of the south island" (p.2)

IEGA: the Amethyst Hydro scheme, at the Hokitika GXP and the entire Upper South Island. This is an area that the Authority has already acknowledged will benefit from more generation to defer an impending transmission upgrade." (p3)

TLC: "TLC's network has been configured to utilise available embedded generation. The diversity of generation means that there is a high degree of reliability that results.

The generation provides numerous technical benefits and has meant that TLC has been able to defer entering into new investment contracts with Transpower….TLC supports a form of ACOT for properly incentivised embedded generation, believing that the technical and cost benefits are significant." (p.8)

The Authority fails to recognise the benefits of DG
Mainpower: "The Authority continues to ignore the value provided by distributed generation, including being the only alternative to investment in transmission assets and enabling retail competition." (p.1)

Molly Melhuish: "The Authority's position on ACOT payments exemplifies the drive to suppress DERs [Distributed Energy Resources]." (p.4)

55 Modelling

Modelling was useful
MEUG (NZIER): "The options paper provides sufficient modelling to indicate the direction and orders of magnitude of the reallocation of the grid costs under the base option and also to demonstrate how the charges might be calculated in practice." (p.25)

PwC (p.14)

Modelling is not robust
TNT2 "the analysis underneath it is not robust" (p.1)

Modelling was not transparent
Contact (p.6), Counties Power (p.8), ASEC for Electra/KCE (p.2)

ASEC for Electra/KCE: "the ability to conduct accurate analyses was hampered by the poor availability of data. Even something as simple as AMD is not readily available" (p.2)

Contact "Given the release of data with a financial impact can affect a company's share price, any numbers published by the Authority must be transparent, capable of being audited and backed up by good numbers. Unfortunately this has not been our experience on this occasion" (p.6)

Modelling was not in an accessible format
ASEC for Electra/KCE (p.15), Counties Power (p.8), PwC (p.14), Contact (p.7)

Contact: In relation to the Authority's use of Python and Linux, the Authority should either use an industry common language or ensure the models run smoothly on all platforms with support during the consultation phase. Requiring parties to switch between multiple platforms to be able to use the Authority's models (with data manipulation required at each step) is not desirable (p.7-8)

Contact "Data management [Contact suggests]… Data output aligns with next step data inputs." (p.8)

Fixation on financial modelling
NZ Energy: "Another concern is the EA's fixation on using financial and theoretical modelling. Why isn't the EA getting their feet dirty and getting out in the work place and finding out how the industry works…" (p.3)

Issues with the data
Contact: "Use of outdated market data, pre significant upgrades, which significantly reduces the value of the analysis…[Contact suggests] Use calendar '14 data, which was a mean year with all upgrades in place." (p.7)

Rates of return used were not a reliable indicator
Contact (p.8)

Transpower was able to broadly replicate the calculations
Transpower: "Our attempt to replicate the charges presented by the Authority in their workshop, using NBV and the residual methodology proposed, yielded a comparable result. There was a slight reduction in the North Island EDB swing, offset by the South Island EDBs. This reflects a refinement of the 15% simplifying assumption and a more accurate allocation of maintenance costs." (p.14)

Issue with allocating actual maintenance costs to assets
Transpower: "For lines, we were able to apportion the 2014 maintenance costs against the circuits that comprised a line element in SPD. However, for the substation and transformer assets, an average rate had to be applied because we could not determine costs generated against the connection vs. interconnection assets, or transformer vs. substation assets. This rate was determined using the same logic as currently applies under the connection charge methodology." (p.11-12)

Excessive assumptions
ENA: "the demand assumptions used by the Authority appear excessive relative to demand growth experienced…It is not clear what effect this assumption may have on the analysis" (p.6)

Results highly sensitive to assumptions
Pioneer: "the modelled results are highly sensitive to the assumptions…This sensitivity means the proposed options cannot be durable." (p.3)

Inaccurate assumptions
Pioneer: Pioneer's [correct] variablised rate is "$22.30/MWh" (p.3)

ASEC for Electra/KCE: "The Authority has also assumed that Transpower's total revenue requirement is $1,000m [however] In the final year of … (RCP2), the forecast MAR is $957m excluding pass-through costs." (p.8)

ASEC for Electra/KCE: MAR / Opening RAB is close to 20% whereas the Authority assumed 15%. Thus deeper connection and AoB charges are understated. (p.8)

Transpower: For Transpower's modelling, Transpower "set the capital recovery to 13.6% of the NBV (the Authority used 15%). At 13.6% the recovered revenue from the deeper connection charge was equal to the revenue collected under a replacement cost approach, which we know from our connection charge methodology, recovers our full costs associated with the assets." (p.11)

Transpower: For Transpower's modelling "Asset revenue as a proportion of NBV varies depending on the age of the asset. For example, we may recover around 10% of the NBV as a capital component in year 1 of an asset's life, increasing to 13.6% in year 14 and 65% in year 35." (p.11)

Matters for which further modelling is necessary
BusinessNZ: Modelling of impact on SMEs is required (p.4)

Contact: Future modelling should include wind generation (p. 8)

Fonterra: A forecast of potential transmission charges could be provided to assist users to estimate their transmission charges. (p.6)

Kawatiri Energy: "Have the EA modelled our business. If so why haven't they provided us this information? …How will our business be affected if there is a further reduction in load on the West Coast as a result of increased charges from the new TPM!" (p.1)

MEUG (NZIER): "There is no analysis comparing the expected size of the EDB cost increase to recent price increases (an indicator of political acceptability). Nor is there mention of demand elasticity … or tipping points for the take-up of alternative technology." (p.30)

Orion: "We also suggest that the Authority does some modelling which compares results of allocating cost using an HHI threshold of zero with those of allocating as much cost as possible on an AoB basis. We suspect there is little difference overall." (p.6)

PwC: "It may be useful to conduct some game theory analysis to test the impact of the proposed TPM on participant behaviours to identify whether they will behave as the Authority expects" (p.7)

Unison: "The Authority should model deeper connection assets at times of system stress, because it may well be that there are widespread beneficiaries during those times. If so, those assets should arguably be treated as interconnection and costs recovered under the residual charge" (p.5)

Unison: "consider modelling the effects of a future reduction in electricity demand [including increased PV scenarios] on the various TPM options" (p.4, 11)

56 Errors

Mischaracterisation of submissions
Vector: The Authority mischaracterised Vector's submission. The reference to Network Waitaki's complaint was put forward as an example of a complaint, not as an example of a case where Vector considered postage stamp pricing lacked efficacy (p.3)

Powerco: The HVDC is the only controversial part of the existing TPM. The Authority mislead the reader in para 4.23 by referring to it as "an example" of controversy in the TPM. (p.2)

The options were mistakenly referred to as a proposal
Marlborough Lines: "when meeting with us the Electricity Authority's representatives referred to the alternatives as "proposals"" (p.4)

Authority misleading public by not publishing variabilised costs
Pioneer: the Authority is misleading the public by not publishing the variabilised cost faced by Pioneer and other smaller generators. The variabilised rate for Pioneer of ~$15/MWh is almost four times higher than the rate for the next generator with the next highest charge (Contact, $3.90/MWh) (p.1)

Modelling errors
Counties Power: "an error of almost 30% in calculation of Counties Power's status quo charges and exclusion of Counties Power's Glenbrook GXP connection in the modelled Application A charges" (p.8)

ENA: "there are numerous errors in the modelling provided" as an example note that the load shares in the Authority's spreadsheet "Deeper_connection_working_assets_covered_in_ Application_A_only_revised_25_June_2015" both the nodal analysis for load and for generation the shares by customer can exceed 100%. (p.6)

ENA: "[for deeper connection] PowerNet has been modelled as a single entity despite being three networks and two counterparties with Transpower; similarly Centralines has been grouped with Unison, despite entirely separate ownership." This drives HHIs. (p.9)

PowerNet: "the inclusion of the Palmerston to Halfway Bush 110kV circuit in the modelling. These assets were purchased along with Palmerston substation from Transpower by OJV on 31 March 2014 and should be removed from the modelling." (p.3)

Pioneer: Despite assistance and a lot of time, Pioneer cannot confirm whether the Authority's injection volume data for Pioneer (41GWh pa of injection) is accurate. Our current practice is to inject roughly 28GWh pa. Pioneer does not know how the 41GWh pa number was derived." (p.3)

Transpower: Deeper connection "Certain grid elements were missing from the Authority's model, or included in error, from the list of deeper connection assets. For example, the model did not include the line between North Makerewa to Three Mile Hill and the connection transmission line from Manapouri to North Makerewa was wrongly included." (p.12)

Transpower: Deeper connection "The Authority's view of our customer base differs from our own, with certain customers missing and others included in error. For example, Carter Holt Harvey connects to the grid via Powerco, Pacific Steel via Vector and Daiken via Mainpower, however they have been included in the Authority's modelling. Conversely, Nelson Electricity, Solid Energy and Southpark were omitted." (p.13)

Transpower (Scientia): Observed the following errors.

- "An error in developing the upstream distribution matrix resulting in incorrect flow allocations to generators.
- An oversight of omitting generation represented as negative load from the upstream trace
- Incorrect loss adjustments on branches with negative flows

These issues were discussed with the Authority and have subsequently been resolved through updates to the flow trace model. We suspect some impact to the calculated deeper connection charges arising from these changes" (p.9)

Inconsistent results from modelling

Pioneer: "The original working paper stated we would save $0.53m in HVDC charges payable under the status quo. The Authority's revised modelling, issued on 30 July 2015, now states Pioneer would face transmission charges of $0.63m per annum – a turnaround of over a million dollars. This cost difference represents more than 24% of our annual generation costs." (p.1)

57 Suggestions/Alternatives

Note: this section includes only those suggestions/alternatives that do not fit squarely in other categories.

TPM: Postage stamp plus beneficiaries pay

Vector (CLEX): postage stamp charge for sunk costs applied to load and generation independent of location; a beneficiaries-pay charge for new investments, using the full LCE towards sunk costs, and allocating the residual on a 50/50 basis. (pages 38-39)

TLC's methodology

TLC: TLC's methodology may offer a solution to some of the issues:

- TLC has a combination of fixed, capacity and demand charges
- TLC allocates a different rate for each of our six consumer groups on the network, ensuring revenue aligns with costs and minimising cross subsidisation.

The effect is a methodology that appears to be durable and provides pricing signals to manage demand that have delayed investment in the network." (p.7)

Broad asset pools/AoB + residual/enhanced status quo

Genesis (Castalia) "we suggest further work focuses on three broad options…

- Defining broader asset pools…For example, pooling within the North and South Islands as well as the HVDC…
- Charges for individual assets. The preferred combination would be an AoB charge with the residual charge. Applying this to new assets only would maximise efficiency…
- Enhanced status quo. This may include applying changes proposed by Transpower and analysing any further enhancements that may be available, such as ensuring parties pay at least marginal cost" (p.iv-v)

Genesis (Castalia): "Options for allocating assets into different pools can be thought of as sitting on a spectrum ranging from a fully national pool to an individual asset basis…the current allocation sits close to the national pooling end of the spectrum, reflecting the underlying philosophy of a "national grid". In contrast, the options … implicitly consider allocation on an individual asset basis... Points in the middle of the spectrum consider different ways to group the asset pool, either by island or by the current four 'transmission regions'" (p.31)

Transmission reserve margin method
EPOC: de-rate transmission capacity in pricing runs of SPD with rentals when reserve margins are violated, adding to the marginal cost of remote generation. Apply method only to costs attributable to beneficiaries of a line. The method will distort short run price signals but will be simpler to implement (p.7, examples provided in Appendix 2)

An exacerbators pays charge
Fonterra: "both options require an element of exacerbator pays included within them. Without an exacerbator pays element, there is a risk that beneficiaries are inappropriately identified" (p.3)

Use of Transpower profits to smooth electricity prices
Mr Peters "after tax profits of state-owned Transpower ($73.8 million in just the six months to 31 December 2014), be instead used to smooth electricity line charges" (p.1)

Review of the Authority
Mr Peters "the Electricity Authority itself [should] be reviewed [due to the high wages of staff]" (p.1)

Ripple control
Bryan Leyland: Temperature- and frequency- sensitive electronic devices could be used on water heaters that would allow the system operator to control demand by altering system frequency. (p.2-3)

Different focus
Molly Melhuish: Focus on "cooperative investment in Distributed Energy Resources" (p.3). Molly Melhuish provided the slides of two power point presentations on "end-use energy options for a reliable electricity supply", and "the potential role of small scale renewable energy in meeting NZ's electricity needs".

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ACOT	Avoided cost of transmission
AIC	Average incremental cost
AMD	Anytime maximum demand
AoB	Area-of-benefit
Authority	Electricity Authority
Capex IM	Capital expenditure input methodology
CAPs	Code amendment principles
CBA	Cost benefit analysis
CIC	Customer investment contract
Code	Electricity Industry Participation Code 2010
DC	Direct-connect customer
DCC	Deeper connection charge
DG	Distributed generation
DME	Decision-making and economic framework
DRC	Depreciated replacement cost
EDB	Electricity distribution business
ENA	Electricity Networks Association
FTR	Financial transmission rights
GIS	Gas-insulated switch gear
GIT	Grid investment test
GWh	Gigawatt hour
HAMI	Historical anytime maximum injection
HHI	Herfindahl-Hirschman index
HVDC	High voltage direct current
IC	Interconnection
ICP	Installation control point
ICR	Interconnection rate
IM	Input methodology
IPP	Individual price path
IR	Instantaneous reserves

kWh	Kilowatt hour
kvar	Kilovolt ampere reactive
LCE	Loss and constraint excess
LMP	Locational marginal pricing
LRIC	Long-run incremental cost
LRMC	Long-run marginal cost
MAR	Maximum allowable revenue
MEUG	Major Electricity Users' Group
MIC	Marginal incremental cost
MW	Megawatt
MWh	Megawatt hour
MRP	Mighty River Power
NAaN	North Auckland and Northland grid upgrade project
NIGU	North Island Grid Upgrade Project
NRS	Network reactive support
PDP	Prudent discount policy
PDWP	Problem definition working paper
PRS	Price-responsive schedule
RAB	Regulatory asset base
RCPD	Regional coincident peak demand
RCPI	Regional coincident peak injection
SFT	Simultaneous feasibility test
SO	System operator
SPD	Scheduling, pricing and dispatch
SRMC	Short-run marginal cost
SRS	Static reactive support
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited