

11 August 2015

John Rampton
General Manager, Market Development
Electricity Authority

By email: submissions@ea.govt.nz

Dear John

TPM: options working paper

We support the Electricity Authority's (Authority) consideration of whether clearly defined problems exist with the TPM and whether modifying the TPM could improve efficiency and promote the long term interests of consumers. We note the Authority's recent TPM 'operational review' decision.

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. Ideally this will not be excessively complex or costly to implement and operate.

We note that the review has been protracted, resource intensive and a source of uncertainty for the sector. We support the Authority's objective of completing its review as soon as possible, though this should not prevent exploration of more moderate reform options.

Overarching points

We have considered the options working paper (OWP), advice from independent experts and Transpower subject matter experts and participated in a number of discussions with the Authority and customers. In light of this we make the following overarching points.

1. The OWP is a positive step at this stage in the TPM review process that should improve the ability of stakeholders to engage and assist the Authority's thinking.
2. While the OWP contains the clearest definition to date of the problems the Authority sees with the current TPM we believe it overstates these problems and, as recognised by the OWP, needs updating to account for outcomes of the TPM operational review.
3. The OWP has helped identify some basic principles that any option should adhere to. For example, time neutrality and transparency are important, as is avoiding unwarranted complexity and unintended price discrimination between grid users.
4. We consider that there are non-trivial issues with the Authority's base option that require careful consideration and resolution before the base option is taken any further.
5. More moderate reform options should be considered alongside or in place of the complex and radical change options in the OWP.

The remainder of this submission expands on these points and describes the pricing analysis we did.

Introduction

Transpower's regulated revenues are determined by the Commerce Commission in accordance with the Transpower Input Methodologies (IM) and Individual Price Path (IPP). The TPM allocates, but does not directly affect,¹ those revenues to Transpower customers.

We recognise that as this is a working paper, it represents emerging thinking and has not been subjected to a cost benefit analysis (CBA). That said, the Authority has invested heavily in the OWP and may see it as a potential forerunner to a second proposals paper. As such we have endeavoured to understand the OWP and to provide constructive feedback.

To inform that feedback we commissioned two external independent expert reports:

1. **Competition Economics Group (CEG):** Economic Review of TPM Options Working Paper, August 2015 (the CEG report). The terms of reference for this report were to:
 - review and comment from an economic perspective on the analysis and conclusions contained in the Options Paper
 - consider whether there are any alternative options that might better meet the EA's objectives that it might consider including in its second Issues Paper.
2. **Scientia Consulting (Scientia):** Analysis of flow tracing models to calculate deeper connection transmission charges, August 2014 (the Scientia report). We asked Scientia to help us better understand the:
 - details of the flow tracing approach implementation and its application in calculating deeper connection charges
 - potential operational and investment impact the proposed deeper connection charges might have on Transpower and its customers
 - potential stability of the deeper connection charge.

The CEG and Scientia reports are included as appendices A and B respectively. We consider both reports to be of a high standard. We encourage the Authority to carefully consider both reports before progressing further.

We also undertook two discrete internal analyses to investigate pricing effects and to investigate flow trace models, including the Bialek method. Summaries of these analyses are included as Appendix C.

The options working paper is a positive step in the TPM review process

The OWP is a positive and welcome step at this stage in the TPM review process. It provides an opportunity for interested parties to reorient themselves after a long period of issue specific working papers before formal proposals are issued for consultation. In addition it:

- provides the clearest definition to date of the problems the Authority sees with the current TPM, allowing the Authority to benefit from stakeholder feedback on the matter
- identifies, as a key issue, that the current TPM "gives rise to several potentially substantive cost-reflectivity issues". On this point CEG notes that, long-term inefficiencies may arise if the 'wedge' between the benefits customers receive from transmission investments and the charges they pay, grows over time

¹ Although Transpower does benefit if TPM reform helps efficiently reduce capital and operational expenditure.

- provides visibility of the Authority's emerging thinking while still at conceptual stage, allowing the Authority to benefit from stakeholder feedback before advancing a particular option. It also highlights some difficult questions, such as whether change should be prospective or also apply to recent grid investment (Application A versus Application B) and canvasses some creative transition options for Application A
- invites parties to consider whether alternative options, including variations on the options included in this working paper, which should be preferred or considered further. This is a critical development in the TPM review process.²

However, as outlined in this submission and in detail by CEG and Scientia, there are non-trivial issues with the options under consideration within the OWP that point to the need to both rethink these options and to consider alternatives. Therefore, we consider that the Authority's approach of consulting both on its option and inviting alternative options is the right one. It enables more effective stakeholder engagement that the Authority now has an opportunity to harness.

Refinement of the problem definition

As noted above, the OWP provides the clearest definition to date of the problems the Authority sees with the current TPM, allowing the Authority to benefit from stakeholder feedback on the matter.

Section 2 of the CEG report explores the Authority's problem definition in some depth, including the potential implications of the TPM operational review. We note and agree with CEG's assessment that:

The Options Paper raises legitimate questions about the long-term inefficiencies that may arise if the 'wedge' between the benefits that customers receive from transmission investments and the charges they pay grows over time. In *principle*, the greater this disparity becomes, the more likely it is that:

- 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.³

We believe this is the principal issue that the Authority should focus on, together with reaching a conclusion on the allocation of HVDC costs.

The timing of the OWP means the Authority was unable to take account of decisions made as a result of the TPM operational review. Since the OWP was published, the Authority has made decisions in relation to RCPD⁴ and is expected to reach a decision on Transpower's proposed change to HVDC charges in the near future.

We recommend that the Authority update its problem definition in light of those decisions, perhaps this could be done as part of the post project review with Transpower (see below).⁵ In our view there are opportunities to improve the TPM operational review process⁶, both to make the timing and content of reviews more predictable (and promote regulatory certainty) and to streamline the process from our and the Authority's perspectives.

² EA, TPM Options Working Paper, June 2015, Paragraph 1.5

³ CEG, Economic Review of TPM Options Working Paper, August 2015, paragraph 2.

⁴ Electricity Authority, Transpower's proposed variation to the TPM, decisions and reasons paper, August 2015

⁵ Transpower, letter to Electricity Authority, 2nd June 2015, page 2.

⁶ Transpower, 2014/15 TPM operational review, second consultation paper, November 2014, section 9.1.

Basic principles that should apply to any TPM option

A further benefit of the OWP and workshop process is that it has helped highlight to us a few basic principles or rules of thumb to which any TPM option should adhere to. As a starter, we suggest:

1. **Cost allocation should be time-neutral:** a time neutral approach to asset valuation for pricing purposes will help avoid perverse price signals likely arise from an approach that is not time neutral, such as that taken in the OWP. A time neutral approach avoids arbitrary lines in the sand that produce large wealth transfers and is less likely to be perceived as unfair.

In relation to the linking prices to net book value (which is not time-neutral) CEG notes

Because prices are linked to the net book values of the assets, they will be highest immediately after an investment and lowest just before it is replaced. This is the opposite of what efficient transmission pricing requires.⁷

As well as the risk of perverse price signals result in the inefficient utilisation of sunk asset, potentially large wealth transfers and equity concerns, a net book value approach may encourage customers to oppose efficient investment and is not competitively neutral. It is not competitively neutral because two comparable customers receiving an identical level of service via functionally identical assets, prices that differ by an order of magnitude.

A more time-neutral cost allocation, such as that applied under the current connection charge⁸, avoids the inefficient pricing outcomes identified by CEG and substantially moderates the other concerns outlined above. For example, the two customers in question would face equivalent (and competitively neutral) prices.

Nevertheless, any change that results in large wealth transfers should be objectively justified by credible efficiency gains, a robust CBA and be subject to appropriate transition mechanism.

2. **Customers should be treated equivalently:** unless a conscious decision is made to discriminate (for example, on efficiency grounds or to better promote the long term interests of consumers). An outcome of the residual charge design in the OWP, is that loads connected directly to the grid and those connected via distributors are not treated equivalently.

We note that the Authority has recognised this issue and made clear this inequivalent treatment of grid connected and distributor connected loads is an unintended outcome of its attempt to address a separate issue. As part of our sensitivity analysis (Appendix C) we analysed the pricing impact of using a non-discriminatory allocator, anytime maximum demand (although we are not suggesting AMD is the right allocator) for the residual.

3. **Avoids unnecessary complexity:** options should be understandable and implementable by (i) Transpower as TPM administrator and (ii) load and generation customers who respond to price signals.

The OWP presents a base option that risks being so complex as to be not understandable. The LRMC and SPD variants to the base option simply add to that complexity. This complexity seems to flow in part from the Authority's application of its decision making and economic framework. In our view, the DME framework should be viewed as guidance rather than a rigid hierarchy, adherence to which produces unnecessarily complex options or precludes sensible options from consideration.

⁷ CEG, Economic Review of TPM Options Working Paper, August 2015, paragraph 242.

⁸ Which uses undepreciated replacement cost as the allocator.

Put simply, if price signals are clear, coherent and predictable and actually promote efficient consumption, investment and engagement decisions then a TPM could be expected to promote efficiency. In contrast, if combinations of charges are so complex as to be undecipherable and or encourage inefficient consumption and investment choices, then a TPM could not be held to promote efficiency.

4. **Transparent:** that the distributional impacts of individual design choices are made transparent and are objectively justified with direct reference to any changes in policy rationale necessary in light of the \$15 objective.

These principles ought not be controversial but would help address some of the salient issues identified with options in the OWP and, subject to improvements others might make, should be applied to any TPM option.

For the avoidance of doubt, we are not suggesting that these principles should displace the need to adhere to more general principles of good regulatory and pricing practice.

Careful reconsideration of the central option is required

As part of our review of the OWP we commissioned external advice in the form of an economic review by Competition Economics Group (CEG) and a technical review of the deeper connection charge by Scientia Consulting (Scientia). In light of their analysis and discussions during the consultation period with the Authority, its advisors and our customers we consider that there are non-trivial issues with the individual components of the base option and the overall option.

We recommend that the Authority carefully review the CEG and Scientia reports. We would be happy to arrange follow up discussions with the authors (and/or with Transpower subject matter experts).

In our view a rethink of the OWP's base option is required. Specifically, we think that the Authority should seriously consider the status quo and more moderate, targeted reforms as well as, or instead of, the radical change options put forward in the 2012 issues and proposals paper and OWP.

Having recently participated in the Commerce Commission's 'competition matters' conference and 'input methodologies forum' we are alert to the potential impacts of emerging technologies on the electricity sector. 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.

We are encouraged by the Authority's call for alternatives - this allows the sector to be part of the solution and takes pressure off the Authority to come up with all the ideas.

Discrete, specific, proportionate reform options should be considered

We asked CEG to consider whether there are any alternative options that might better meet the EA's objectives that it might consider including in its second Issues Paper. CEG concluded that moderate reform has greater potential to provide net benefits to New Zealand (with considerably lower risk, less disruption and less extreme wealth transfers) than radical reform. CEG also identified three specific alternatives (see section 8 of their report).

We agree with CEG conclusion and recommend the Authority, with input from stakeholders, investigate more moderate reform options that build on what, with some specific exceptions, are a widely accepted and fit for purpose TPM.

Table 1 outlines an example of a more moderate reform option that draws on CEG's 'third option'.⁹ While still a substantial change from the status quo, an option like this would be comparatively simple to implement and understand.

Table 1: conceptual example of 'moderate' reform option

	Charge name	Concept description
1	Connection charge	No change
2	Regional charge	<p>Assigns, where possible, costs of existing and new assets (currently defined as interconnection assets) to specific geographic regions.</p> <p>Regions: uses RCPD regions (are understood by customers, reflect key transmission bottlenecks and correspond with major recent / future investments), the two islands or potentially be more granular.</p> <p>Asset assignment: on basis of flows, geography, benefits or another measure(s).</p> <p>Asset valuation: on basis of undepreciated replacement cost so as to be time neutral (reduces windfall gains / losses, avoid perverse price signals and is consistent with the current deep connection charge)</p>
3	HVDC charge	Assigns the cost of HVDC as determined by the Authority. ¹⁰
4	Residual charge	Suggest that this is the current interconnection charge (RCPD) with the possible addition of a proportion of HVDC costs.

An approach like this could improve the correlation between transmission costs and prices,¹¹ provide incentives for grid users to (i) make efficient consumption and investment decisions (ii) engage constructively in transmission investment decision processes. It would be transparent, predictable and adaptive.

While an option like this would result in some rebalancing of transmission costs across the country the scale of change would be considerably less than implied by the OWP (though may still warrant a transition mechanism).

We recommend that, before the next proposals paper, the Authority engages directly with stakeholders to test and develop alternative options, such as this, that emerge from the OWP consultation. We remain committed to assisting the Authority and stakeholders in this regard.

Pricing operations and sensitivity analysis

Transpower's pricing team sought to replicate the Authority's pricing analysis and to undertake a high level assessment of implementation difficulty (see Appendix C).

⁹ CEG, Economic Review of TPM Options Working Paper, August 2015, section 8.4

¹⁰ The OWP implies allocation of approximately two thirds of HVDC costs to consumers.

¹¹ Recognising that the TPM is cost-reflective from an economic perspective, since all grid users face prices that are greater the SRMC of their usage and less than the stand-alone costs of supplying each customer.

This work also provided an opportunity to examine the pricing effects of the Authority's simplifying assumptions and to test sensitivities identified in workshop discussions. Although we were unable to implement the base option this was a useful investigation and we have previously shared the preliminary findings of our analysis with the Authority.

Sensitivity analysis

The basic approach was to replicate the Authority's price modelling and then to update this in three ways:

1. Revisiting simplifying assumptions. For example, that asset revenue = 15% of net book value (NBV). Although we were unable to implement the deeper connection charge as conceived we were able to refine the simplifying assumption to make it more accurate.
2. In addition to the change described in step 1, treating direct and distributor connected consumers equivalently by adopting the same allocator for the residual. We used anytime maximum demand (AMD) as the allocator; though do not suggest that AMD is necessarily the best allocator.
3. In addition to the change described in steps 1 and 2, adopting a time neutral asset valuation method. We used undepreciated replacement cost (RC) in place of NBV, though recognise our RC estimates are dated.

A fuller explanation of the approach to and findings of this analysis are presented Appendix C.

Other matters

The Authority's engagement

We found the Authority's in-consultation engagement activities around the OWP to be very effective. The workshops were particularly useful in helping us to understand the very complex suite of pricing concepts in the OWP. We recognise and appreciate that the Authority, executive, staff and external advisers went to a lot of trouble to help stakeholders to understand its thinking.

To complement this in-consultation engagement we think more pre-consultation would benefit the process.

Consultation process

We think a longer consultation and potentially inviting cross submissions would have been worthwhile. Earlier in the consultation period the Authority has published updated and new information on its website and informed stakeholders via its market brief channel. On the whole this is a positive practice, though it can complicate stakeholder analysis and increases participation costs.

However, the Authority published two substantive documents on its website on 6 August and 7 August, within a few days of the consultation closing, and, in contrast to its approach earlier in the consultation period did not inform stakeholders. This is not ideal.

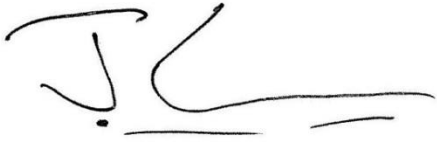
Next steps

We think the next step in this process the Authority should engage stakeholders to help develop and stress-test any alternative options raised through submission and other avenues.

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. We are available to assist the Authority and stakeholders.

I would appreciate an opportunity to discuss the points made in submission with you.

Yours sincerely

A handwritten signature in black ink, appearing to be 'JC' followed by a long horizontal stroke and a small flourish at the end.

Jeremy Cain
Regulatory Affairs and Pricing Manager

Appendices A and B are attached separately

- **Appendix A: Competition Economics Group (CEG):** Economic Review of TPM Options Working Paper, August 2015
- **Appendix B: Scientia Consulting (Scientia):** Analysis of flow tracing models to calculate deeper connection transmission charges, August 2015

Appendix C: Pricing operations and flow trace review

This appendix outlines our approach and findings for discrete analyses during the consultation period for the TPM options paper 16 June – 11 August 2015.

1. **Pricing operations:** an exercise to establish whether, utilising outputs from the Authority's flow tracing and HHI modelling, we could implement the deeper connection charge and to understand certain sensitivities.

The analysis was intended to support Transpower and other parties in assessing the Authority TPM options working paper. Unfortunately, due to a combination of the consultation window, resource and data availability issues we were only able to complete this analysis a few days before the consultation closed. Rather than risk disrupting the process by publishing the information this close to the due date we decided to include a summary in our submission.

2. **Flow tracing review:** The Authority has derived the deeper connection charges using a particular flow trace model from Bialek. We turned to the literature to better understand the Bialek method in the context of NZ grid topology and through that process identified that there are a range of flow trace models that could be used for transmission cost allocation. We outline some of the different methods and specifically discuss the allocation outcomes of the Bialek method.

1. Pricing operations and sensitivity analysis

The purpose of this note is to summarise analysis undertaken by Transpower's pricing team. The analysis had three specific objectives:

- **Could we implement the deeper connection charge as contemplated in the OWP?** The OWP proposed using Net Book Value (NBV) and actual maintenance and operating costs to allocate deeper connection charges. We assessed practicality of applying this logic, as compared to the current replacement cost (RC) methodology used for the connection charge, given our current asset and cost datasets.
- **Could we expand or enhance the high-level price effects scenario analysis provided by the OWP?** The OWP provided figures that illustrate the impact of the proposed charges, using a number of simplifying assumptions. For example, that the recoverable capital, maintenance and operating cost against each deeper connection asset was 15% of the NBV. Where possible, we attempted to improve upon these assumptions using actual cost information and offer an alternative solution to what may be more practical.
- **What are the sensitivities around the central options in the working paper?** The tables presented in the OWP highlighted large wealth transfers that create 'winners and losers'. We sought to better understand the drivers of these shifts.

Implementing deeper connection charges

Map deep connection elements against the pricing assets in our register

To replicate the deeper connection charges requires an 'SPD view' of our assets. This differs from the current view in our financial information system (FMIS) which identifies assets as discrete e.g.

lines, substations, transformer, switchgear. The relationship between an SPD 'arc' (or circuit) and a 'line' in our asset register is not one-to-one. To translate our FMIS cost information to SPD information; we mapped lines to circuits and made adjustments for any connection or interconnection distinctions to avoid double recovery.

Replicate the deeper connection charge using book values and actual costs

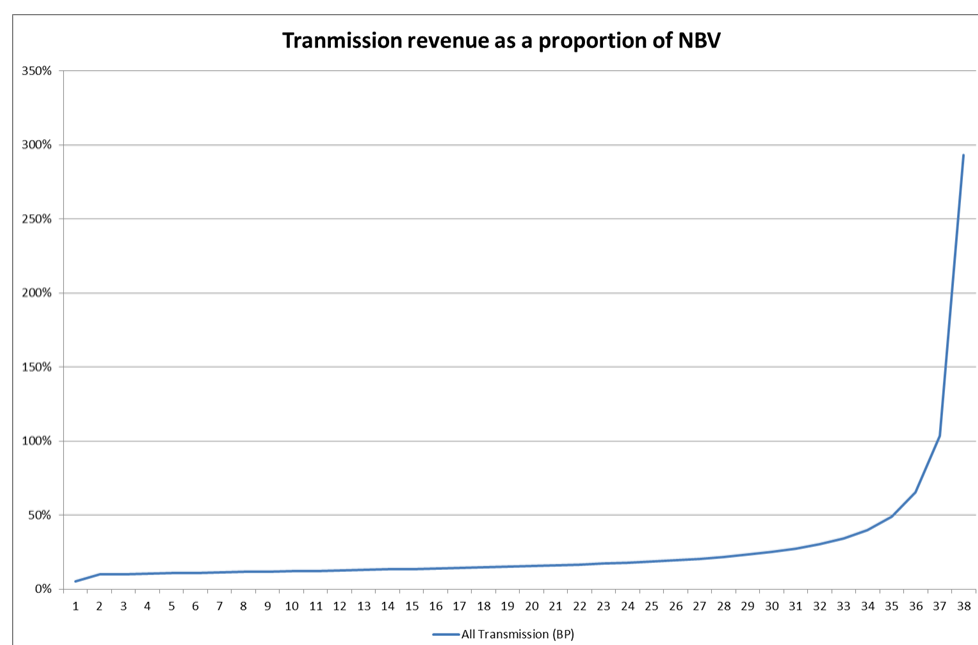
After translating our asset view to the SPD element view, we could then assign a NBV against each element. NBV requires an asset life. The assignment was complicated because the different components that make up an asset, or element, may all have different remaining lives. E.g. for a transmission line¹², the painting work, reconductoring, and insulator replacement occur at different intervals, therefore all the component parts of the line have a different remaining life and it becomes a subjective exercise to conclude an average remaining life.

Our objective of determining the exact capital recovery for elements was not possible at this time. It may be possible given more time though that the cost of doing so with precision may be high (we have not attempted to estimate costs this at this point).

This led us to impose a rule of thumb like the Authority did and 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.

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. This is illustrated in figure 1.

Figure 1: transmission revenue as a proportion of NBV



Maintenance and operating costs are recorded at the substation and line level. We do not record maintenance or operating costs against the specific transformer, switch, circuit or the like that has generated the cost. 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

¹² The original value of the original line is, in many cases, fully depreciated.

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.

Replicating the deeper connection charge using undepreciated replacement cost

The current connection charge approach uses replacement cost to assign capital, maintenance and operating costs to customers. This approach charges according to the type and number of assets deployed rather than the accounting value of the assets deployed. This reflects the fact that the type and number of assets directly impacts the service received by a customer whereas the asset's age and accounting treatment typically do not. A similar point was made in our and other submissions to the connection charges working paper.

Table 1 presents the following rates that were applied against the replacement cost determined for each SPD element. The rates methodology used is that prescribed for determining the connection charge rates¹³.

Table 1 Deeper Connection Charge inputs compared with connection charge inputs

	2015/16 Connection Charge	Modelled Deeper Connection Charge
Asset Return Rate	7.80%	8.36%
Substation Maintenance Rate	2.00%	1.72%
220kV Maintenance Rate	\$5,381/km	\$3,093/km
Other Tower Maintenance Rate	\$7,269/km	\$4,026/km
Pole Line Maintenance Rate	\$8,387/km	\$3,324/km
Cable Line Maintenance Rate	NA	\$TBC ¹⁴ /km
Operating Rate	\$1,016/switch	\$1,016/switch

General observations

Linking SPD elements to FMIS assets was difficult and time consuming. 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.¹⁵

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

¹³ Line maintenance rates are higher for connection assets due to the effect of our asset transfer programme.

¹⁴ We do not yet have sufficient cost data to calculate this rate.

¹⁵ This process is relatively straightforward with only two HVAC asset distinctions; if it isn't connection then it will be interconnection and in both instances the same asset classification is used. The proposal contains multiple asset boundaries, each of which has a different classification. For example, a line that isn't a connection asset may be a deeper connection or area of benefit asset, if it is a deeper connection asset then the classification switches to the SPD asset view which considers the circuits making up the line. To continue to be engaged in this process, our stakeholders would need to understand this complexity and be able to interpret what it means for them.

Makerewa to Three Mile Hill and the connection transmission line from Manapouri to North Makerewa was wrongly included.

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.

We note that the replacement cost methodology, as applied to the existing connection charge, is considerably more straightforward to implement than a net book value methodology. It is understood by our customers and translates to Transpower recovering the full cost incurred by the assets.

Sensitivity analysis

As well as replicating the Authority's modelling we updated the analysis in three ways:

Step 1. Update simplifying assumptions. For example, that asset revenue = 15% of net book value (NBV). As outlined above, we were unable to implement the deeper connection charge as conceived but we were able to refine the simplifying assumption and apply a more accurate allocation of maintenance costs.

Step 2. Step 1 plus equivalent residual allocator for direct and distributor connected consumers. We used anytime maximum demand (AMD) as the allocator; though do not suggest that AMD is necessarily the best allocator.

Step 3. Step 2 plus a time price methodology for the deeper connection charge. We used undepreciated replacement cost (RC) in place of NBV.

All other charges were taken as presented in the OWP. Table 2 presents charges by customer group under the current TPM (2015/16 charges) alongside those presented in the OWP (columns 'status quo' and 'OWP').

Table 2 Revenue allocations between customer groups under sensitivities

	Status Quo	OWP model	Step 1	Step 2	Step 3
Direct Connect	10%	3%	3%	7%	8%
Generator	19%	15%	15%	15%	18%
UNI EDB	24%	38%	35%	34%	28%
LNI EDB	27%	27%	28%	25%	25%
USI EDB	14%	12%	14%	14%	15%
LSI EDB	6%	5%	6%	5%	6%

Observations

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.

The replacement cost methodology also 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.

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.

NB. These results should be viewed as indicative only. We have had to retain some simplifying assumptions and do not have a complete set of undepreciated replacement costs for all grid assets. We did not attempt to replicate or test sensitivities with the area of benefit charge (AOB), i.e. numbers in table 2 reflect the AoB charge as per the OWP analysis.

Future Analysis

The figures above are the result of exploring the options as far as we could in the time available.

With more time, we would have liked to have run the deeper connection model with the omitted elements for completeness, as well as reconciliation between deeper connection to AOB assets. The constraint on this was determining the appropriate HHI and flow trace implications.

Furthermore, we intend to analyse the practicality of using actual cost as the replacement cost for cable sections. Where the ODV does not contain a replacement cost for an asset class, the accepted practice is to use the full cost at the time of commissioning. This has created a disproportionate mark-up on the replacement cost for underground cables as compared to overhead lines.

We also did not have time to replicate or test sensitivity for the AoB charge by customer as provided by the Authority.

2. Flow trace allocation methods

The purpose of this section is to summarise the engineering research undertaken to understand the following:

- **What are the flow trace models that could have been used?** The deeper connection paper¹⁶ indicated that “flow tracing would be used to identify assets that are predominately used by only a small number of parties” and “flow tracing attributes the proportion of total electricity flow on each transmission asset to individual loads and generators”. In seeking to learn more about the flow tracing we discovered there are several flow tracing models that could be used for allocating transmission cost.¹⁷
- **What are the allocation characteristics given the choice of the Bialek model in New Zealand network topology?** All mathematical models for power flow require approximations and assumptions which can influence the results. We wanted to understand how the choice of Bialek method influences the allocations in the NZ grid context.

Flow trace models

From the academic literature we find that there are several flow trace methods that have been explored for allocating transmission costs¹⁸ (as well as our former operational transport methodology). On interconnected (loop flow) parts of the grid that are being allocated, flow trace methods do not represent physical reality but instead offer a method of creating numbers that represent a set of hypothetical load flows that are mutually consistent. At least as applied to the interconnected grid, each method is essentially a choice of an arbitrary mathematical model, with additional approximations such as the linearisations of the non-linear power flow equations into network ‘flow’ components associated with individual customers.

The main flow trace methods are:

1. Bialek’s flow trace method (proportional sharing)
2. An incremental transfer calculation (marginal method)
3. A MW-distance method (minimum energy solution)
4. A direct network model (Z-bus) method (not considered further here)

The research concluded that the allocation results under each method are different and are heavily influenced by the topology of the network.¹⁹

To test this observation Transpower carried out some comparative analysis using a 16 to 20 bus representative model of the North Island network. We conclude that the North Island topology and the prevailing flow towards Auckland are highly significant factors on the allocations that result. For instance, the topology makes MW-distance methods unsuitable for the flow allocations (see section 3.4). The analysis identified specific allocation biases under the Bialek method due of grid topology (which is not to say that other methods present no bias, we have not tested this, simply that those biases need to be understood in order to make an informed decision as to a flow trace method²⁰).

¹⁶ Electricity Authority, TPM options working paper, Companion paper, June 2015, Section 2.6 and 2.7

¹⁷ An implication of this is that the selection of the Bialek method is a potentially significant policy choice.

¹⁸ Evaluation of Transmission Pricing Methodologies for Pool Based Electricity Markets, Paper accepted for presentation at the 2011 IEEE Trondheim PowerTech, G. A. Orfanos, G. T. Tziasiou, P. S. Georgilakis, Senior Member, IEEE, and N. D. Hatzigiargyriou, Fellow, IEEE

¹⁹ Ibid.

²⁰ Such as the ‘agreement’ on using the mathematical model SPD as the market solve tool.

Bialek method (the approach for deeper connection charging)

The model algorithm uses an assumption of pro-rata (proportional) sharing of outgoing flows from a node based on the magnitudes of incoming flows. The combination of flow direction and this proportional flow sharing assumption means that if an infeed becomes part of a prevailing flow in the network it will continue to be allocated a share of assets until that flow reaches the last load. Conversely, if an infeed acts to displace the prevailing power flow towards a load it is not visible in the flow share allocation.

As a result, if the Bialek method is used for transmission asset allocation it can lead to the counter-intuitive result that particular generators at one end of the network are contributing to inter-regional flows in the transmission grid but somehow other generators connected in the same region as the load being served are not. This is despite the actual effect on the inter-regional power transfers in the transmission grid being the same for all generation from any given region.

The analysis shows that the North Island topology will make this unintuitive distributional effect quite obvious. For the North Island, flow direction is often continuously northwards from Haywards to Marsden. Generation output that becomes part of this directional flow (e.g. Tararua Windfarm, Tokaanu, and Rangipo) will be allocated a share of nearly all North Island transmission line assets, whereas other generators connected in similar regional locations (e.g. West Wind windfarm, some generators within the Wairakei Ring etc.) will not be allocated any of the grid assets.

Transmission system usage and flow direction

Figure 1 and Figure 2 show the effect of transmission system use and allocation based on flow direction. In figure 1 the loads at C and D are met by 350MW flow from Bus A. Then assume that 100 MW additional load needs to be met at Bus C. The generators that could meet this, at GEN E and GEN F, could geographically be very close to Bus B, figure 2.

Figure 1 100 MW load at Bus C

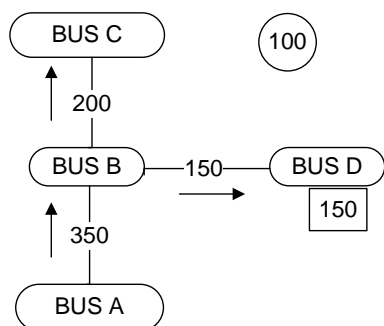
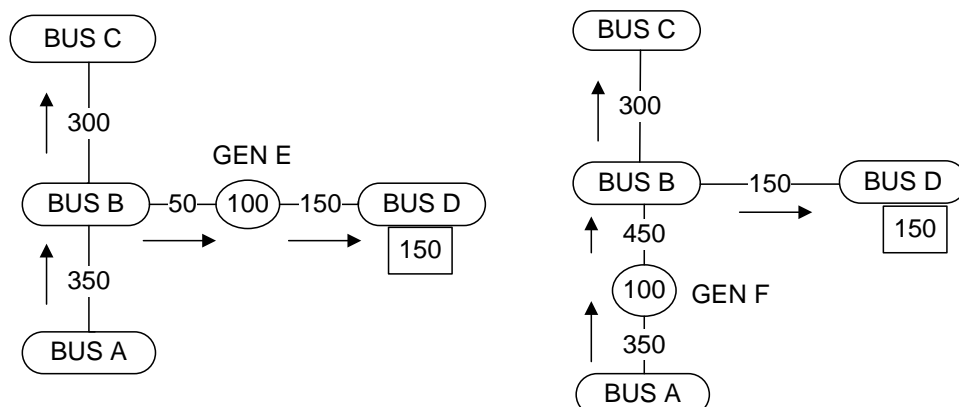


Figure 2 Generation at location E or F to meet 100MW at Bus C



The effect of either generator is to increase flow from B to C by 100 MW. The 100MW increase at Bus C could be met by Gen E or Gen F. If from Gen E then Bus D is met by 100MW from Gen E plus 50MW coming from Bus A. If from Gen F then the 150MW at Bus D would be met by flow from Bus A. We don't actually know where the power has come from to meet the 100MW at Bus C.

Bialek's flow tracing would attribute substantial flows north towards Bus C to Gen F and nothing to Gen E, as Gen E's output would not be seen in the prevailing grid flows towards Bus C. The flow trace would instead attribute it to generation that was already connected south of Bus B. Gen F in series with a faraway load is at a disadvantage compared with Gen E (in general it is a disadvantage to be in series with the prevailing flow) as all its output gets allocated. If the load at Bus D was always greater than Gen E, then location E would never be allocated any transmission costs.

The New Zealand grid has many examples of generation connections where the effect of flow supposition would be evident; for example, Rangipo, Tokaanu, Te Mihi would be Gen F's whereas generation like West Wind and generators in the Wairakei Ring could find themselves in the Gen E position.

For the North Island, flow often continues from Haywards to Marsden, so small generators that become part of this flow will be assigned usage of assets many hundreds of kilometers away even if these assets are physically on the other side of load that is in excess of the generators output.

We conclude that the Bialek method biases allocation (of North Island transmission assets) towards generators that are part of the prevailing flow whereas other small generators connected in similar regional locations, or closer to the remote assets, will not be assigned any of the flows. We note that this systemic bias is a different bias to generators that arises from the design choice for the treatment of losses in the method.²¹ We have not attempted to quantify the materiality of the bias.

Marginal method

The marginal (or incremental) method is a measure of the change in the transmission system use due to a generator or load change. There are many implementations of marginal or incremental transfer methods. Conceptually they are quite straightforward – if the output or load at a bus changes, there is a change in the flows on the transmission system. Some generators and load changes will increase the use of the transmission assets and others will decrease use. Most likely is that there will be an increase in use of some grid assets and a decrease in use of other assets depending on the load and dispatch conditions at the time.

To find an incremental effect on flows it is necessary to modify both load and generation. For a generator assessment it is common to assume all the load increases to meet the generation increment. However, for a load increment most networks would meet this from the marginal generation. A simplification is used (typically scaling of all generation or scaling of the largest generation infeed site) because although theoretically possible to include the generation merit order in the marginal assessment this is not usually done.

The method is computation-heavy as each connected party requires their own calculation for each time period being considered. The method's advantages are that it automatically includes conditions where a specific connection has beneficial effects at some time but not at others (depending on loads, dispatch etc), and it is transparent and provides the same signals for all participants in the same region of the transmission grid. For some network topologies, the method will produce a negative value (e.g. common for a small generator connecting into a large remote load for instance, or for a load connecting in an exporting region).

²¹ See Scientia Consulting report, Appendix B of our submission.

MW-distance methods

These methods are based on assumption that a minimum energy solution is consistent with normal physical processes, for example when electric current flows through a network it divides in approximately inverse proportion to the impedance of the branches. For a simple resistive network, the resultant flow is the minimum energy solution.

The network topology gives the distance between each load and each generator, where distance is usually treated as a physical (km) distance but could also be denoted as electrical distance (impedance). For the dispatched generator set and the load set the method tries to find a set of generator-load transactions that has the lowest MW-km sum. In other words the power is delivered to all the loads with the minimum possible MW flows on the grid. The usual option is to minimise the total MW-km, however it is also possible to adopt other optimisation targets, such as minimising the largest single MW-km participant.

Having obtained a transaction set, each transaction is modelled separately on the grid and the line assets then allocated based on the proportion of flows in a line for any generator or load compared to the sum of the flows in the line for all transactions.

On meshed grids, the allocation that results is from each generator to the closest loads. This result then leads to the allocation of only geographically close transmission assets, an ‘intuitive’ result. Unfortunately the method is not guaranteed to be a single-valued result. Our analysis shows that because the North Island so often has a large prevailing flow towards the Otahuhu and Pakuranga bus the minimisation cannot be single valued. The WKM bus acts as a collector bus for all incoming flow south of it, and MW-distances from there onwards all become equivalent. A secondary method would be needed (e.g. pro-rating) for all such flows North from Whakamaru.

Figure 3 shows a sample power flow result from our 16 bus test system. The circles are generation/infeed, and the squares are loads, netted with embedded generation. The result illustrates the issue caused by the North Island network topology; except for Ohinewa - Hamilton all flows are towards the top.

Figure 3 sample power flow result

