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1 March 2013

Carl Hansen
Chief Executive
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By email: carl.hansen@ea.govt.nz

Dear Carl

Transmission Pricing Methodology Consultation

Please find attached Transpower's submission on the consultation paper *Transmission Pricing Methodology: issues and proposal*.

Transmission pricing is challenging and has a history of causing dispute. As a sector, we have allowed this challenge to divert resources and attention away from issues that have greater potential to improve outcomes for consumers. This was our experience in the 1990s when Transpower governed transmission pricing.

The Authority has put forward a novel approach to trying to resolve this challenge. While the proposal is intellectually seductive, using a complex modelling approach to setting transmission pricing will only increase disputes. The old arguments over allocating the costs of past investments will continue, and will be cloaked in more complexity.

We should not be trying to change something that is not broken. Rather than a radical departure from current arrangements, Transpower's view is that we should be holding to a stable, simple and durable approach to transmission pricing so that we can collectively direct our focus and resources at matters more likely to deliver benefits.

A possible exception is the HVDC, where there are acknowledged inefficiencies in the current methodology. Elements of the Authority's approach may provide a mechanism to improve that and this should be tested through industry consultation against other options.

Yours sincerely

Patrick Strange
Chief Executive

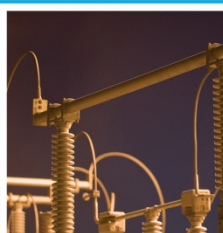
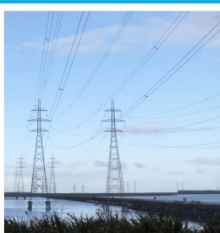
Transmission Pricing Methodology

Submission on Issues and Proposals Consultation

Transpower New Zealand Limited

1 March 2013

Keeping the energy flowing



TRANSPOWER



Submission by Transpower New Zealand Limited

on

Transmission Pricing Methodology: Issues and Proposals Consultation

To: Carl Hansen
Chief Executive
Electricity Authority

Date: 1 March 2013

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Executive Summary

The Electricity Authority (**the Authority**) is proposing changes to the transmission pricing methodology that we use to allocate our regulated transmission revenues to our customers. The Authority's proposed changes are intended to impact future transmission investment decisions, and to reduce lobbying by parties seeking to reduce their share of transmission costs.

Any change affects Transpower both as administrator of the methodology and grid owner. Our submission covers implementation issues, matters we consider relevant to the Authority's statutory objective, and the objectives of improving the efficiency of transmission investment and reducing lobbying.

We support in principle the intent of improving investment efficiency by identifying and charging beneficiaries. However, the proposal raises concerns due both to its complexity, and the high risk of unintended consequences.

Connection charging framework

We recommend the existing connection asset charging framework is retained without change. We understand that our principal connection counterparties share this position.

The costs of providing connection assets are currently recovered either under the pricing methodology (via connection charges) for asset replacements to maintain services, or under a bilateral customer investment contract (**CIC**) for new assets to expand capacity.

The Authority view is that differences between the two cost recovery approaches create an incentive to avoid CIC-based investment. It has proposed that all asset replacements should be charged based on actual project costs (rather than an average cost based on the connection asset pool) and that the Authority should arbitrate any disputes that arise.

This would be less effective than the status quo. Under these proposals:

- customers would experience 'rate-shock' (going from a pool charge, to a new asset charge) when, to maintain service levels, we carry out end of life asset replacements. This may mobilise opposition to such replacements, which would hinder our ability to maintain services using rational asset management decisions.
- referral of disputes to the Authority would put the Authority back in the position of a second transmission regulator, which is exactly counter to the intent of the reforms that led to its creation.

The current approach is not perfect. However, it has proved enduring and effective. When adding new connection capacity the distributor (or generator) is cost neutral as to whether they build the asset themselves or contract us to do it. When delivering existing service, our customers are effectively cost neutral as to whether or not we renew an asset. This allows us to optimise effectively across the network and means that how we do this is, rightly, our decision as asset owner.

Development and implementation issues

There are a number of development and implementation issues, principally with the proposed SPD charge.

We have carried out work during the consultation period to identify key implementation issues, and to estimate the time and cost required to develop the pricing system required by the Authority's proposal.

Based on the current proposal, we estimate the practical implementation date is 1 April 2017 and that the direct cost (excluding costs for our customers) could be up to \$20 million initially and more than \$1 million per annum thereafter.

Time and cost would be reduced by simplifying the proposals; for instance; by setting charges annually in advance rather than on a monthly lagging basis, and retaining the existing definition of transmission customers.

The proposals would increase the complexity of the relationship between revenue-setting, regulated by the Commerce Commission (**the Commission**), and pricing. The proposed SPD charge would require development of detailed rules for grouping assets, representing the removal of those assets in the pricing grid, and calculating the annual capital-related charges for those assets. Limiting the SPD charge to a small set of asset groups would help make these challenges more manageable.

The proposals would add small generators, retailers, and other wholesale market participants to our customer mix. This would require interfaces with retail reconciliation systems to allow allocation of charges at a sub-GXP level. This will add significant complexity to pricing systems and to our customers' bills.

Existing commercial structures for demand-side participation, distributed generation, and prudent discount agreements will be disrupted by shifting most transmission charges off distributors. This is likely to undermine the value of existing investments in distributed generation in particular.

Pricing outcomes will be sensitive to modelling methods and assumptions. This will expand the scope for lobbying. There will also be a larger number of parties with a direct interest in lobbying for pricing changes. We do not agree with the Authority that the proposals will reduce costs of pricing-related disputes and lobbying.

Interconnection charges

HVDC assets would be added to the interconnection pool, with costs recovered through four charges – a kvar charge to signal the cost of grid-connected reactive support equipment, an 'SPD charge' based on 'spot' assessment of the beneficiaries of particular groups of assets, a regional coincident peak injection (**RCPI**) charge on generators to recover half the 'residual' revenue requirement, and much reduced regional coincident peak demand (**RCPD**) charge to recover the other half of the residual.

We acknowledge that the current HVDC charge has some problems, and that the Authority has proposed an innovative potential solution. However, the Authority has not demonstrated that there are material problems that would warrant a change to interconnection charges.

We have an obligation to assess the transmission pricing methodology against the Authority's statutory objective, and commissioned Competition Economists Group (**CEG**) to carry out an independent, high-level critique of the proposals from an economic perspective. Although not directly part of our submission, we have attached the CEG report as Appendix B for completeness.

CEG identified some serious concerns with the SPD and RCPI charges from an economic perspective. In particular:

- the charges may alter generator behaviours in ways that reduce the efficiency of the wholesale market. The economic costs of this may significantly outweigh any potential benefits.
- the volatility of the charges may harm competition, and may have a 'risk amplification' impact that will cause an increase in delivered electricity prices.
- the charges will not accurately reflect the benefits of transmission investments (either in terms of approximating private benefits for individual parties, or providing a clear indication of overall benefits of investments).

Given the materiality of these concerns, it is clear that further policy design work is required before the Authority finalises its pricing guidelines.

It is proposed to review the definition of RCPD regions and recalibrate the number of measurement peaks per region. There is value in maintaining stability in the RCPD charge to avoid undermining the benefits of distributed generation and demand-side capability. We would be reluctant to significantly reduce the RCPD charge. However, there may be merit in a framework for allowing gradual, forecastable, 're-tuning' of the RCPD signal over time.

HVDC charges

Pricing of the HVDC assets has always been contentious and there are particular incentive problems with the current HVDC charge. There have been several proposals for change but none have been implemented. If a change is warranted now, the following points should be considered:

- Any 'unbundling' of the collective HVDC assets (e.g. charging for Pole 2 and Pole 3 separately) will require difficult allocation decisions regarding common costs (e.g. operating costs, and common assets, such as towers, cables, and site infrastructure).
- A decision would be required on how to allocate the 'legacy' economic value account balance (currently ~\$100 million).
- A one-off (or, at least, infrequently recurring) assessment of beneficiaries would be less costly and less problematic than more frequent assessments. The assessment should be used to set an allocation that does not need to be revisited, and be structured in a way that allows parties to forecast their charges. The SPD methodology could potentially be used to carry out this assessment.

Transmission investment efficiency

The concern is that grid investment processes lack adequate stakeholder engagement and that there is a systematic risk of the Commission approving inefficient grid investments. We do not believe that evidence supports these concerns, or that the proposed pricing changes would improve investment efficiency. To the contrary, there is a risk that the proposal will motivate obstructive or vexatious engagement to the detriment of investment efficiency.

The Authority's particular analysis, which compares SPD charges with the revenue requirement for an asset, is invalid:

- SPD charges are based on artificial 'spot' estimates of aggregate private benefits. These estimates are capped each half hour, and also do not capture benefits that arise over a longer timeframe, that are not reflected in wholesale market prices, or that are too complex to model accurately.
- The size and timing of transmission investments is based on net market benefits over the forecastable life of the assets. Rather than make many incremental investments, it is usually more efficient for investments to be 'too big' in the early years following investment.
- Transmission planning uses 'prudent' demand forecasts because the reliability-related costs of commissioning too late are usually significantly higher than the costs of being too early. This approach means that investments should usually appear to have been made too early when assessed after the fact.

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Appendix A – Responses to consultation questions

Appendix B – CEG report

1 Introduction

We welcome the opportunity to submit on the Authority's *Transmission Pricing Methodology issues and proposals paper*.

Transpower administers the pricing methodology, and will be required to develop the Authority's guidelines into full pricing rules. In this capacity, we have a direct interest in the development and implementation of the pricing system and its on-going operation. We are also the grid owner, and so have an interest in the impact of the proposals on development and use of the grid.

Our submission is structured as follows:

- Section 2 comments on the connection charging framework
- Section 3 assesses key development and implementation issues
- Section 4 comments on interconnection charges
- Section 5 comments on HVDC charges
- Section 6 addresses transmission investment efficiency
- Appendix A provides our responses to the Authority's specific questions.

As administrator, the Code requires us to assess the transmission pricing methodology that we develop against the Authority's statutory objective¹. We have therefore commissioned independent economic advice from CEG on the Authority's proposals. This does not form part of our submission, but is included at Appendix B for completeness.

During the consultation period, we have also developed and published information that may assist parties considering the Authority's proposals. Our submission is informed by this work, which can be found at:

www.transpower.co.nz/tpm_development

¹ Electricity Industry Act 2010, Section 15, *The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers*

2 Connection charging framework

The Authority seeks to modify existing connection asset pricing arrangements such that replacement of existing connection assets would trigger a change from the current pool-based connection charging approach, to charging based on recovery of specific project costs

We recommend that the status quo should be retained. We understand that the Electricity Networks Association, representing our principal connection counterparties, supports this position.

The Authority is also proposing that existing connection assets should be 'locked in' as connection assets. This change is unnecessary, and not supported by evidence of any material problems.

2.1 Pool charges are appropriate for end of life asset replacements

Under the current methodology, the aggregate value of all connection assets² is allocated to connected parties, based on the type of assets they use³.

This 'pool-based' approach means that customers' charges are smoothed over time. For example, if a customer's fully depreciated asset is replaced with a new asset, then the value of the connection pool increases but that customer's share of the pool remains the same. This approach is applied where we are investing to maintain service levels, and is consistent with the concept that connection customers are purchasing a service, rather than the specific assets used to supply the service.

The concern is that this approach differs from the way charges are calculated under the bilateral CIC arrangements we use when a customer wants us to expand capacity. In contrast to the connection asset approach, CICs are used to recover the actual capital-related costs of providing specific assets to a customer. This means that a customer will typically⁴ pay a charge that declines over the life of the asset.

In theory, these differences in cost recovery approach could provide customers an incentive, if they had the choice, to avoid CIC-based investment. Similarly, customers could, if they had the choice, prefer to avoid self-funding.

To address this concern, it has been proposed that all asset replacements should be charged based on actual project costs, and that the Authority should arbitrate any disputes that arise.

This would be much less effective than the status quo. Under these proposals:

- Customers would experience 'rate-shock' (going from a pool charge, to a new asset charge) when, to maintain service levels, we carry out end of life asset replacements or substitute assets at one location to achieve better outcomes across the asset fleet. This may mobilise opposition to such replacements, which would hamper our ability to maintain services using rational asset management decisions.

² \$136.6 million for the 2013/14 pricing year.

³ We note that allocation to customers is based on 'building block' costs from a now somewhat dated pricing book. This sometimes causes confusion because the building block costs do not reflect current replacement costs. In practice, this does not matter because building block costs are only used as an allocator. The value of the connection pool is based on current regulatory valuations, not on building block values.

⁴ The charging profile depends on contract-specific funding arrangements.

- Referral of disputes to the Authority would put it back in the position of a second transmission regulator, which is exactly counter to the intent of the reforms that led to its creation.

While the current approach is not perfect, it has proved enduring and effective.

For expansion, the distributor (or generator) is cost neutral as to whether they build the asset themselves or contract us to do it. For maintaining existing services, our customers are relatively cost neutral as to whether or not we renew an asset. This allows us to optimise effectively across the network and means that how we do this is, rightly, our decision as asset owner.

There is no evidence that there is a material issue concerning the two cost recovery methods, and the status quo arrangements should be retained.

2.2 Locking in connection assets is unnecessary

The issues paper describes two examples, provided by us, where there is the potential for investment to cause an unintended reclassification of some assets from connection to interconnection. As noted in the paper, this is a minor issue and, in the only example where investment is actually progressing, has been resolved satisfactorily.

Given that there is no evidence of a problem, the status quo should be preferred.

It would be risky to make a change to 'lock-in' connection asset status. Situations could arise where it would make sense to reconfigure the grid such that some assets legitimately changed from connection to interconnection.

3 Development and implementation issues

There are a number of development and implementation issues, principally with the proposed SPD charge. This section of our submission:

- summarises our cost and timeframe estimates, suggests options for simplifying the proposal to reduce time and cost, and recommends that, if the proposals proceed, there should be a gradual transition
- covers matters relevant to the relationship between revenue setting and pricing
- highlights issues to be addressed with the addition of purchasers (including retailers) and small generators to our customer mix
- comments on the risk of increased pricing-related dispute and lobbying.

3.1 Timing, costs, and transition

Our current estimate is that the proposals will have a direct cost (excluding costs to our customers) of up to \$20 million initially and more than \$1 million per annum thereafter. The practical implementation date is 1 April 2017. These requirements would be reduced by simplifying the proposals.

We recommend that the transition include a period of parallel operation, and that, if the proposal proceeds, revenue should be only gradually transferred across from the existing pricing system.

3.1.1 Implementation costs have been underestimated

We sought independent advice from PwC on the likely cost and timing implications of the Authority's proposals⁵. PwC examined our existing pricing systems and processes, and mapped the requirements of the proposal to develop indicative costs.

PwC estimated indicative costs of \$13 million for implementation, and \$4 million on-going costs over the first five years (these are incremental to our existing pricing costs). PwC expects that its estimates could vary by up to +/- 50%.

These figures exclude the costs of developing the pricing guidelines into full pricing rules. The Authority has estimated a cost of \$0.5 million for this process. Given the legal, economic and technical input needed, and the stakeholder engagement required to ensure a robust product, we expect a cost of \$1.5 million is a better estimate.

Our upper bound estimate of our direct costs over the first six years is close to \$30 million. The comparable figure used by the Authority is close to \$15 million⁶.

The PwC figures have wide uncertainty bounds, but we are confident the cost of implementing the proposals would be materially higher than modelled in the Authority's cost-benefit analysis.

3.1.2 2017 is earliest practical 'go live' date

PwC estimate that it would take 18 months to implement the pricing systems required by the proposal. In addition, we recommend:

⁵ PricewaterhouseCoopers, December 2012, *Transmission Pricing Methodology – Impact Assessment*, <https://www.transpower.co.nz/about-us/industry-information/transmission-pricing-methodology-development-2012-electricity#implementation>

⁶ Under the Authority's 'pessimistic' scenario, up-front costs are \$4.75 million and operational costs are \$2 million per annum.

- a period of 12 months should be allowed for developing the pricing guidelines into full pricing rules. The process will be technically challenging, will require some critical design decisions, and customer engagement to ensure a robust product
- a further period of 12 months of parallel operation (including providing customers with 'shadow' invoices). The pricing systems and processes will produce complex outputs (for example, a small retailer may have more than 3000 charge components per month⁷). Parallel operation will confirm the systems are operating correctly, while allowing customers to understand how their charges change over a year.

We consider 1 April 2017 is the practical implementation date assuming final pricing guidelines are available by June this year.

This is our initial estimate and can be refined when there is a clear understanding of the final proposal.

3.1.3 We recommend a gradual transition

We recommend revenue should be only gradually shifted over to the SPD and RCPI charges following parallel operation. Parallel operation will not enable our customers to understand how market behaviour will change once the SPD and RCPI charges are being used to collect revenue.

A gradual transition will manage the impact of the charges on participant's businesses, and the risk of unintended consequences⁸. This would be consistent with the Authority's preference for a small-scale trial and error approach in circumstances where benefits are not clear.

3.1.4 Simplifications could reduce costs

Key design changes that could reduce the time and cost required would be retaining an annual pricing cycle, retaining the existing definition of transmission customers, and reducing the number of assets subject to the SPD charge.

A monthly charging cycle increases the need for process automation, reduces exception handling and error resolution timeframes, adds to direct operating costs, and creates more scope for billing queries and disputes. A monthly process also alters the pricing process assurance task.

Adding wholesale market participants increases the number of billing relationships, and means pricing systems must interface with retail reconciliation systems to enable sub-GXP allocation.

The retail reconciliation system generates a monthly sequence of successive approximations and wash-ups that extend for more than one pricing year. Including retail wash-ups in transmission charging would significantly increase billing complexity – for example, a small retailer could have more than 3000 new charges each month, and a further 6000 or more wash up adjustments⁹.

⁷ This assessment is based on charges for 64 SPD charge asset groups across 50 GXPs, plus RCPD charges for each of those GXPs (i.e. $64 * 50 = 3,200$ charges).

⁸ It could be achieved by limiting the number of assets transitioned (for example, only using SPD charging for the HVDC initially) and by only shifting a portion of those asset's revenue requirements (for example, only 10% initially).

⁹ In the extreme, wash ups could be processed each month for 15 months, leading to nearly 50,000 charge components for a small retailer. A large generator-retailer could have close to 250,000 charge components per month.

It is proposed that all assets commissioned since 2004, and with a value in excess of \$2 million, have their costs recovered via the SPD charge. Our estimate (see below) is that there would, depending on the detailed asset definition rules, be 64 eligible asset groups in 2015. The pricing and billing process would be simplified by selecting fewer assets for the SPD charge. Including only future investments worth more than \$100 million would result in a considerably simpler process.

3.2 Revenue setting and price setting

Figure 1 illustrates the outcome of work we carried out to assess the impact of various value thresholds for including assets in the SPD charge.

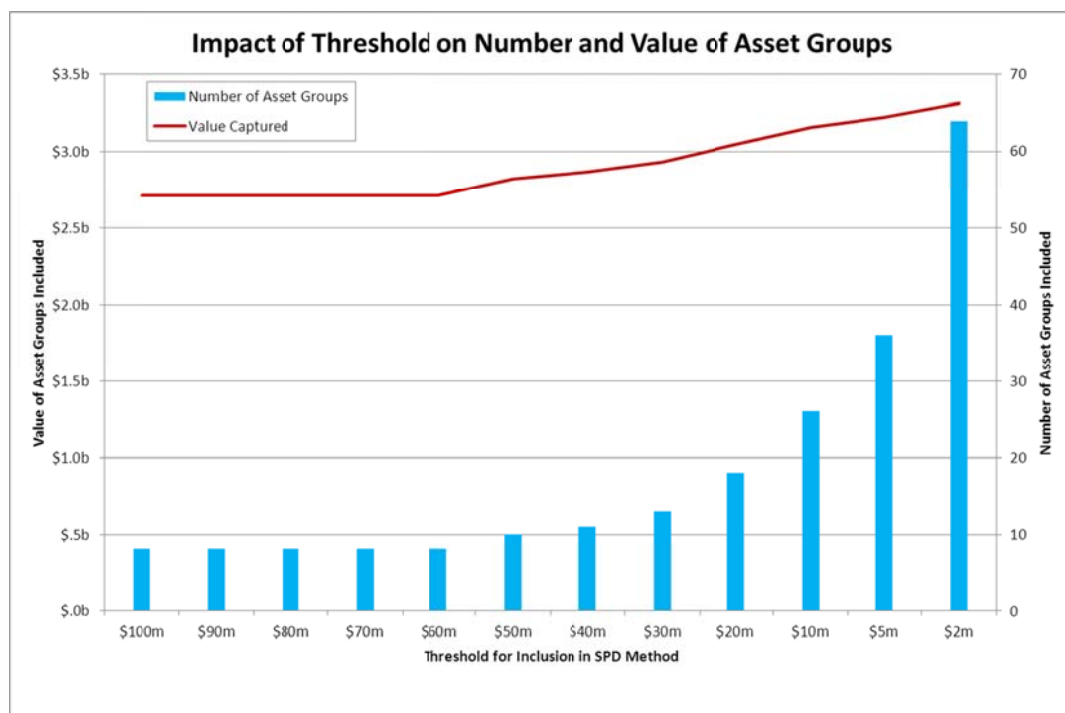


Figure 1 - Impact of asset value threshold for SPD charge

The proposed threshold would capture 64 groups of assets, with a collective value of around \$3.3 billion. The number of groups captured, and the value of those assets, could both vary depending on the methodology for grouping assets and attributing values.

The granularity used to assess asset boundaries is important – each of the asset groups identified above includes a large number of financial assets, and a smaller number of ‘building block’ assets. In practice, an investment can enhance an existing asset such that the aggregate value of the final group of assets exceeds the value of the investment.

The SPD charging approach requires the revenue requirement of each asset group to be isolated and used to establish a cap on the half-hourly charge. This would include an assessment of capital related costs, and an allocation of operating and maintenance costs.

Capital-related transmission costs are recovered based on calculation of regulated revenue ‘building blocks’ – a capital charge, depreciation charge, and tax pass-through. This is illustrated below for a nominal transmission asset with a 30 year economic life.

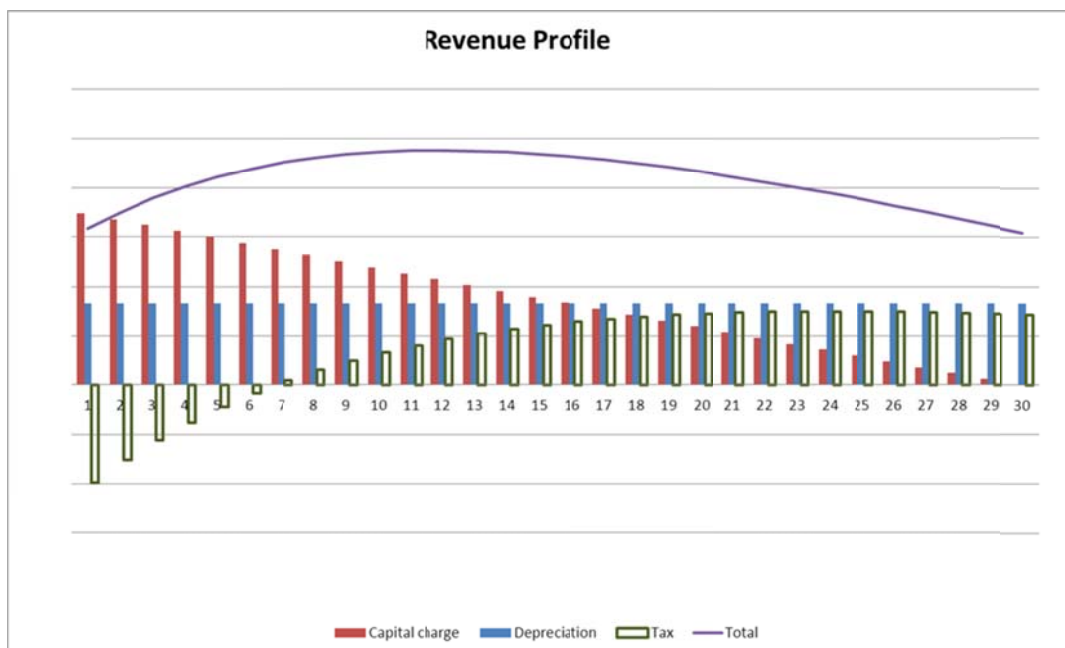


Figure 2 - Revenue building blocks for a nominal asset¹⁰

An individual investment is likely to involve multiple assets that are progressively commissioned over a number of months or years. The revenue setting process requires us to forecast the assets to be commissioned in year 'N' and to 'wash-up' any difference between the forecast and actual commissioning profile in year 'N+2'. This process will be too complex to accurately replicate in the cap-setting process and a simpler method will be required.

The current approach to allocating operating and maintenance costs uses simple representative charges for costs – for example a \$ per km charge for lines maintenance and \$ per switch charge for substation operation costs. A more targeted approach would not be supported by our current systems, would result in an unstable allocation of costs, and would prove impractical.

Each asset group captured by the SPD charge would require determination of how removal of the relevant assets would be represented in the SPD pricing grid. This would typically involve deciding in advance how the pricing grid would be represented under a range of different operating and market conditions so as to limit the need for operator discretion. We expect that conditions would still arise during the monthly modelling runs that would require manual intervention.

We caution strongly against setting a \$2 million threshold. This would introduce too much complexity in terms of asset accounting, revenue setting, operating the SPD pricing model, and billing customers.

3.3 Customer profile

The proposed SPD charge (and possibly the RCPI charge) would add several new classes of market participant to our customer base – non grid connected generators, retailers and other purchasers.

¹⁰ Under current regulatory rules, there is no depreciation charge in the first year and end of life depreciation is always spread over a (typically five year) regulatory control period (i.e. depreciation cannot terminate part-way through a control period). These rules are not reflected in the above profile.

3.3.1 Proposals alter commercial structures

The SPD charge and RCPI charges would reduce the amount of revenue that we recover via distributors. If all distributors took the option to opt-out of the RCPD charge, then revenue recovered via distributors would reduce from \$716 million to \$136 million¹¹. This change would:

- significantly alter the economics of embedded generation and demand-side investments, including impairing the value of many existing investments
- alter the commercial value of prudent discount agreements, notional embedding agreements and other such arrangements.

The impact of these changes could be particularly significant for any distributed generation that currently receives an RCPD-related payment (to reflect the transmission costs that a distributor avoids through hosting embedded generation). In most cases, RCPD payments to distributed generators would reduce from the \$99.44/kW that applies in 2013/14 to between zero (if the distributor opts out) and less than \$50/kW¹².

Prudent discount applications usually arise in circumstances where the notional bypass project has implications for a distributor's charges. Prudent discount agreements typically involve a tripartite agreement between Transpower, the bypass proponent and the affected distributor. Under the proposed changes, notional bypass projects would be based on avoiding SPD or RCPI charges. As such, the prudent discounts would logically be a bipartite agreement between Transpower and the bypass proponent.

Further work is required to establish the possible implications of altered financial flows on established commercial structures.

3.3.2 Contracts may not be appropriate for non-connected customers

Currently our customers only include parties with a physical connection to the grid. These customers are all reasonably stable counterparties with a material capital commitment to their businesses. Here a contractual framework is a logical means of dealing with charging and prudential arrangements. It provides a mechanism for agreeing technical connection details and, in theory, we have the option of disconnection and recovery of connection assets as a last resort to managing prudential risk.

This contractual framework may not be appropriate for non-grid connected parties. The contracts with these new parties would only cover our pricing relationship – we would have no other commercial interactions. There is also no way we can withdraw supply to non-paying customers that do not have a physical grid connection.

Alternative approaches here include adding transmission charges to the current wholesale market prudential arrangements, or simply relying on 'wash-up' processes. Our existing inter-year wash-up mechanism could be supplemented by a within-year pricing adjustment mechanism to ensure that Authority's proposals do not cut across the Commission's regulation of our revenues.

3.4 Proposals will increase costs of disputes and lobbying

We do not agree that the proposed changes will reduce the costs of lobbying and dispute, because:

¹¹ Based on charges for the 2013/14 pricing year.

¹² If SPD charges were zero, then the RCPD charge would reduce to less than \$50 due to the RCPI charge accounting for half the residual. As the SPD charge grew over time, the RCPD would reduce further.

- the complexity of the proposed charges introduces many points of contention (both in design and operation) and the wealth transfers involved will encourage increased dispute and lobbying
- the proposed charges expand the range of parties able to dispute charges or to lobby for changes
- the SPD charge is likely introduce more dispute and lobbying into the Commission's investment approval processes.

We expect that decisions regarding assets definitions, modelling approaches and input parameters will be particularly contentious.

This potential for contention is highlighted by the following chart, which illustrates the impact of different choices of capping period on the incidence of the SPD charge.

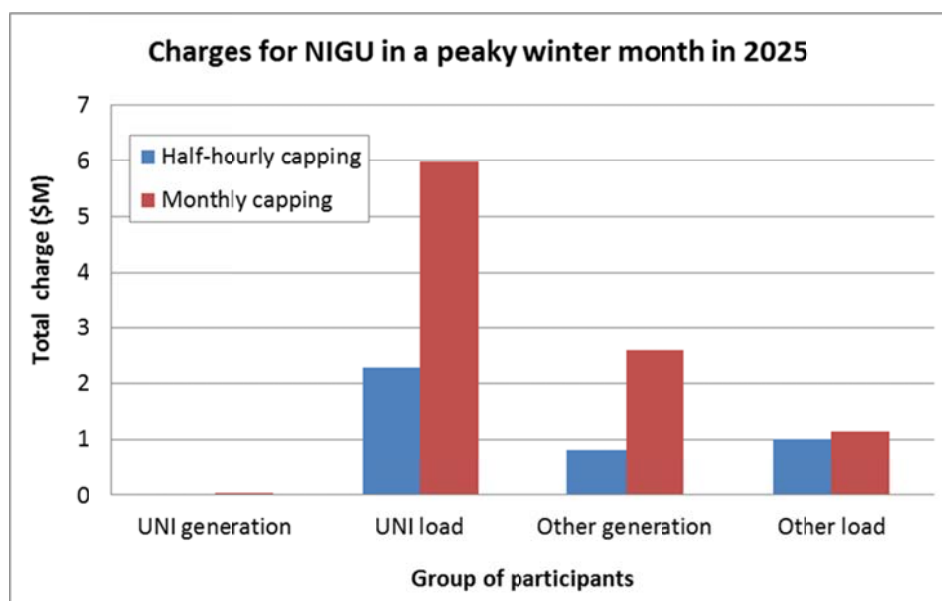


Figure 3 - Illustration of the impact of design choices on SPD charges

In this example, a longer capping period is a more realistic approach, but shifts costs significantly to consumers in an importing region. Other design choices will have similar impacts and are likely to also be contentious, both during the development of the pricing methodology and on an on-going basis.

4 Interconnection charges

HVDC assets would be added to the interconnection pool, and costs recovered through four separate charges – a kvar charge to signal the cost of grid-connected static reactive support equipment, an ‘SPD charge’ based on ‘spot’ assessment of the beneficiaries of particular groups of assets, a RCPI charge on generators to recover half the ‘residual’ revenue requirement, and much reduced regional coincident peak demand charge to recover the other half of the residual.

The current HVDC charge has some problems and there is scope for some improvement: however, the Authority has not demonstrated that there are material problems that would warrant a change to current interconnection charges.

This section covers each of the interconnection charge proposals in turn, and proposed changes to the prudent discount policy. The HVDC charge is covered in a separate section.

4.1 Economic Review

We have an obligation to assess the transmission pricing methodology against the Authority’s statutory objective, and therefore commissioned CEG to carry out a high-level critique of the proposals from an economic perspective. Although not directly part of our submission, we have attached the CEG report as Appendix B for completeness.

The CEG report focusses on the proposed SPD and RCPI charges, and identifies serious concerns from an economic perspective. In particular:

- the charges may alter generator behaviours in ways that reduce the efficiency of the wholesale market. The economic costs of this may outweigh any potential benefits.
- the volatility of the charges may harm competition, and may have a ‘risk amplification’ impact that will cause an increase in delivered electricity prices.
- the charges will not accurately reflect the benefits of transmission investments (either in terms of approximating private benefits for individual parties, or providing a clear indication of overall benefits of investments).

Given the materiality of these concerns, it is clear that further policy design work is required before the Authority finalises its pricing guidelines to ensure a robust pricing methodology can be developed.

4.2 The SPD charge

The Authority’s proposed SPD charge is an innovative approach to targeting charges at beneficiaries.

We do not have any objection to aligning charges with beneficiaries in a workable and durable way. However the proposal as it stands raises concerns:

- The proposed charge involves *ex post* assessment of beneficiaries each half hour. In contrast to making a one-off assessment prior to investment, this encourages market participants to avoid charges by avoiding use of unconstrained transmission assets, which is inherently inefficient.
- The charge would apply retrospectively to transmission investments back to 2004. Such broad retrospective application may undermine confidence in the predictability of future charges.

- The charge would vary each month, and would not be known in advance. In conjunction with the charge being too complex for parties to accurately forecast, this approach would introduce new risks for generators, retailers and other purchasers. Parties would not have any ability to hedge this risk¹³, and the risk would flow through to higher end consumer prices. The charge may reduce competition given it is likely to be particularly challenging for smaller retailers, generators, and purchasers.
- The charge depends on complex model-based assessment of beneficiaries. This will significantly increase the risk of pricing errors, and will create contention over data inputs, and modelling approaches. There will be circumstances where the pricing operator is required to exercise discretion to obtain a solution, and this will invite dispute, as has occurred as with pricing outcomes using SPD in the wholesale market.
- The full market system used by the System Operator is engineered for real-time processing rather than the batch operation required for monthly processing, and can also not be made available to customers. The Authority's vSPD is not revenue-grade software. For example, a pricing system requires robust auditable change controls, and systems to ensure continual alignment with the market system. As no existing system is suitable, a bespoke solution may be necessary.

As it has not been demonstrated that there are material problems with existing interconnection charges, we cannot see any reason to introduce an SPD charge that carries these risks.

If the Authority decides to adopt an SPD charge for interconnection assets, then further development work is required to fully understand the likely consequences. The charge should:

- only be applied prospectively to interconnection assets
- only apply to a limited number of the largest transmission investments
- be calculated and set in a way that allows parties to forecast their annual charges.

4.3 RCPI

Half of the 'residual' revenue requirement would be recovered via an RCPI charge on generators. The only reason for this proposal is to reduce inadvertent price signalling by spreading the residual across more parties. This rationale is not compelling, because applying a charge to generators is likely to *increase* unintended price signalling.

As with the current HAMI component of the HVDC charge, generators can alter their behaviour in an effort to avoid charges. Both HAMI and the proposed RCPI charge penalise intermittent and low-capacity factor generation types, such as wind and run-of-river hydro.

The Authority suggests Transpower use the RCPI to provide a pricing signal in regions that are becoming export constrained. Nodal prices provide an efficient signal in such circumstances and we would not anticipate using the RCPI charge to discourage generation at peak times.

Given the risks, and the absence of a clear rationale, we do not support the introduction of an RCPI charge.

¹³ We note that Transpower would not be a suitable hedging counterparty, because monthly fluctuations in the SPD charge would alter who we obtain revenue from, but we would continue to recover a flat revenue profile over each pricing year.

4.4 RCPD

The RCPD charge would be retained but the number of regions and the number of peaks per region would be reviewed.

We cannot identify any clear benefit from reviewing the RCPD regions. The upper North Island and upper South Island have an on-going need for incremental transmission investment. The current demarcation is well understood by participants, and is not intended to provide tightly targeted pricing signals. Changing regions frequently would undermine the credibility to the pricing signal that RCPD does provide to optimise the timing of transmission investment and encourage non-transmission solutions.

Regular changes to RCPD would deter investment in load control and distributed generation: however an appropriately designed mechanism could be developed that allows parties to understand the criteria that would apply to a gradual recalibration of the RCPD pricing signal, following a major investment, or to support further initiatives to reduce peak demand to defer investment.

4.5 Kvar

We agree with the proposal to introduce a kvar charge where required, and to set a minimum power factor of 0.95 lagging in the connection code.

The consultation paper describes the kvar charge as recovering the cost of static reactive support assets. However, as the charge is based on the long-run marginal costs, it has a cost signalling objective rather than a cost-recovery objective.

4.6 Loss and constraint excess (LCE)

LCE would be offset against the charges relating to the assets on which the excess arose.

We do not support this proposal because it would have the effect of muting nodal pricing signals, which would reduce the efficiency of those signals.

LCE should continue to be rebated independently of the pricing process. This achieves the same end effect on customers, while avoiding the need to embed an additional monthly input into the price setting process.

4.7 Prudent Discount Policy

Two changes are proposed – removal of the 15 year cap on the duration of prudent discount agreements, and extension of the policy to include cases where a customer's notional investment involves disconnection from the grid (rather than just bypass).

Removal of the cap is appropriate. However, we do not support extending the prudent discount policy to cover notional disconnection.

It is difficult to place a value on the various benefits of grid connection compared to self-supply. Grid connection generally allows a customer to readily expand their consumption, and provides reliability and quality benefits that self-supply is unlikely to match. It is difficult to determine an appropriate WACC for the annuity payment relating to a generation investment.

4.8 Conclusion on interconnection charges

We are not persuaded that the scale of change that the Authority proposes is warranted, or that the various charges have been well enough tested to be sure they should be pursued.

The SPD and RCPI charges have particularly high risks of unintended consequences. Our strong preference is for a stable pricing methodology over time, and for fundamental changes only to occur if there is a very compelling case that the new approach is sound and will bring significant benefits.

Overall we need a simpler, more limited set of charges. The large number of interacting charges is an undesirable feature of the Authority's proposal.

5 HVDC

Pricing of the HVDC assets has always been contentious and there are incentive problems with the current HVDC charge.

Previous industry forums and regulators have proposed, but never successfully implemented, changes to HVDC charging.

If it can be established that a change is warranted, the SPD methodology could form the basis of a solution. The SPD method (or some other method) could be used to make a one-off assessment of beneficiaries. This would be far less costly to implement than constantly updated assessments, and would avoid adverse impacts on generation offer behaviour.

The one off assessment of beneficiaries could also be used to set an allocation that does not need to be revisited over time, with a charge structure that allows parties to forecast their charges.

This option should be evaluated against previous, simpler options.

The Authority's proposal involves 'unbundling' of the collective HVDC assets (i.e. charging for Pole 2 and Pole 3 separately). Any unbundling will require difficult allocation decisions regarding common costs (e.g. operating costs, and common assets, such as towers, cables, and site infrastructure). The same issue would arise if HVDC assets were split between existing assets, and the current upgrade project.

The benefits of the combined Pole 2 / Pole 3 system is greater than the sum of the benefits of its parts operating alone. Some of the Pole 3 project investment also increased the capability and life of Pole 2.

A change to HVDC charges would also require a decision on how to allocate the 'legacy' HVDC economic value account balance (currently ~\$100 million). Once we have a clear proposal, we will need to ensure it is consistent with the Commission's revenue-setting rules. The rules recognise HVAC and HVDC revenue as separate lines of business with separate economic value accounts. These rules may not operate correctly if HVDC revenues are split, and if a residual amount is bundled into HVAC revenues.

6 Transmission investment efficiency

The concern is that grid investment processes lack adequate stakeholder engagement and that there is a systematic risk of the Commission approving inefficient grid investments.

The evidence does not support these concerns, and the proposed pricing changes would not improve investment efficiency. To the contrary, there is a risk that the proposal will motivate obstructive or vexatious engagement to the detriment of investment efficiency.

The Authority's particular analysis, which compares SPD charges with the revenue requirement for an asset, is invalid:

- SPD charges are based on artificial 'spot' estimates of aggregate private benefits. These estimates are capped each half hour, and also do not capture benefits that arise over a longer timeframe, that are not reflected in wholesale market prices, or that are too complex to model accurately.
- The size and timing of transmission investments is based on net market benefits over the forecastable life of the assets. Rather than make many incremental investments, it is usually more efficient for investments to be 'too big' in the early years following investment.
- Transmission planning uses 'prudent' demand forecasts because the reliability-related costs of commissioning too late are usually significantly higher than the costs of being too early. This approach means that investments should usually appear to have been made too early when assessed after the fact.

6.1 SPD charges under-represent benefits

The SPD method uses wholesale market spot prices to estimate the aggregate private benefits of a transmission investment to generators and purchasers.

The method cannot capture any benefits that are not reflected in wholesale market prices. For example, outage planning flexibility, option value, resilience, and retail market competition benefits.

The method relies on demand levels and generator offers that occurred in the real world with the subject investment in place. It provides only a 'spot' estimate of the benefits of the investment being in place for the given trading period. If the investment had truly not been made, then market participants would be likely to have made different decisions regarding offer strategies, fuel and reservoir management, unit commitment, and investment. These factors are not captured by the method.

The method necessarily makes a number of simplifying assumptions to achieve a workable modelling approach. For example, it does not take into account the impact that a transmission line may have on 'group constraints' (i.e. overall limits on a group of circuits along a common corridor), stability limits, reserve requirements and prices, or frequency keeper selection and prices. As a general observation, these simplifications tend to reduce the SPD charge compared to what would be calculated with a more realistic modelling approach.

The 'raw' figures calculated by the method are capped to arrive at a charge. The capping approach can have a significant impact on the size of the charge, as indicated by the following analysis based on the NIGU investment.

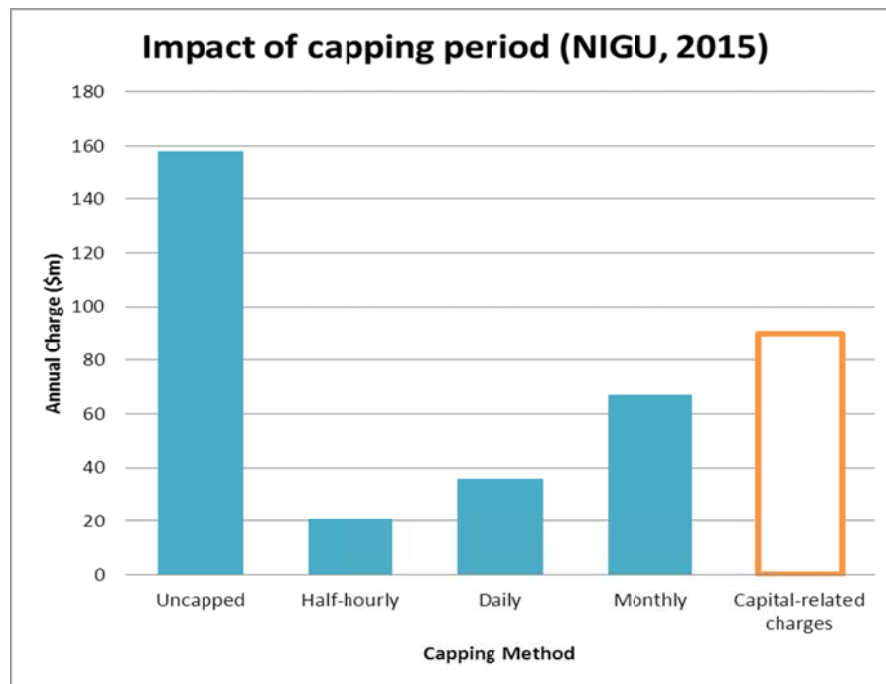


Figure 4 - Impact of capping (NIGU, 2015)¹⁴

In combination, these factors mean that the size of the SPD charge for an asset over a year is not a reliable indicator of the benefits of that investment.

6.2 Benefits are assessed over a long period

When selecting the size and timing of a transmission investment, we consider costs and benefits over a long period (typically 20 years). This ensures that we do not select a solution that will require a series of subsequent incremental upgrades in cases where it would be more efficient to make a larger one-off upgrade.

In most cases this approach will select a higher-capacity (more costly) solution than would be selected if the objective were to minimise costs only in the first few years following investment. In other words, it is usually more efficient for investments to be 'too big' in the early years following investment, than to require repeated upgrades.

This means that assessing the benefits of an investment in the early parts of its life does not reveal anything meaningful about whether the sizing or timing of the investment was efficient. Benefits will generally increase over time (typically due to increasing demand), whereas capital-related charges decline over time as the assets depreciate.

¹⁴ For more information on the assumptions under-pinning this analysis, refer <https://www.transpower.co.nz/about-us/industry-information/transmission-pricing-methodology-development-2012-electricity#vspd-modelling>

6.3 Transmission planning uses 'prudent' demand forecasting

The timing of grid investment is guided by the Authority's grid reliability standard (**GRS**). For the 'core grid', we are required to maintain an 'n-1' security standard. This means that timing is typically based on commissioning an upgrade in the year that the security standard is otherwise forecast to be breached¹⁵.

Transmission projects usually have long lead times (for example, seven to 10 years for new transmission lines). This means that timing is often selected based on forecasts prepared up to 10 years ahead of the commissioning date. It is always uncertain how demand will change over a 10 year period, and how long it will take to build any given project.

Investment timing risks are asymmetric for transmission – that is, the cost of being too late (usually loss of supply) is higher than the cost of being too early (deploying capital earlier than would be optimal with perfect information and no risks).

Given these considerations, transmission planning uses 'prudent' demand forecasts to determine the timing for investments. These are forecasts with a 10% probability of being exceeded. In other words, we plan to build more times than not. This prudent approach has traditionally been necessary to deliver a reliable supply of electricity.

We are committed to the use of non-transmission solutions to reduce investment timing risks and are currently investing in development of a technical and commercial platform for procuring demand side response. Where we are confident that we can procure sufficient demand-side response or other initiatives at a reasonable cost, we will be able to move toward timing closer to an 'expected' need date for transmission investments.

The timing for major projects has been based on the prudent planning approach and this should be reflected in any backward-looking assessment of the benefits of these investments over the early years of their lives. In other words, investment should usually appear to have been made too early when assessed after the fact.

6.4 Engagement in grid investment processes

The discussion above demonstrates why the SPD charge does not provide a good indication of investment efficiency.

There is no evidence that there is a problem with systematically poor grid investment approval decisions, and we do not accept the SPD charge would improve transmission investment decisions. Instead, there is a risk the SPD charge could have an unintended effect of delaying or obstructing efficient investments. This is because:

- the charge associated with an asset may exceed the private benefits for some parties, particularly in the early years following investment (when the charge is highest and benefits are lowest)
- the charge does not 'net off' dis-benefits to particular parties (for example, due to increased competition from lower-cost competitors), meaning that some parties may face a targeted charge for an investment that has a net-negative impact on them
- in some circumstances, generators will be able to shift charges to consumers by structuring their offers to minimise their apparent benefits

¹⁵ The GRS and the Commission's capital expenditure rules also require investment when there is an opportunity to deliver net market benefits (that is, where market benefits are forecast to exceed costs). The timing for these investments is determined by analysing costs and benefits to forecast the most net beneficial timing.

- due to the way the charge is calculated, a new investment alters the allocation of SPD charges for all prior investments, and this effect may outweigh the benefits of the subject investment for some parties.

We welcome constructive engagement in transmission investment decisions. This can help to bring new information or ideas to light, and to stress test assumptions. However, the SPD charge may mobilise obstructive or vexatious opposition to efficient investments due to the mis-alignment of pricing impacts on individual parties and the net market benefits of particular investments.

There is currently a good level of constructive engagement in investment approval processes, and little risk of the Commission consistently approving inefficient levels of grid investment.

Appendix A – Responses to consultation questions

Question	Response
1. What are your views about the materiality of changes in circumstances since the current TPM came into force in 2008?	<p>It is not clear that changes identified by the Authority qualify as material in the context of clause 12.86.</p> <p>There is not a clear link between the first two of these ‘material changes’ and the substance of the Authority’s proposals because:</p> <ul style="list-style-type: none"> • We expect to make very few large investments in coming years, so the potential benefits from deferring grid investment are limited at this time. In other words, there is a mismatch between the material change cited, and the pricing change that is proposed. • We cannot see a link between the proposed changes to the pricing methodology, and the governance changes that have occurred over the past several years. If anything, the changes have made the proposals less supportable because governance of investment efficiency is now consolidated under the Commerce Commission.
2. What comments do you have on the process that the Authority has outlined for developing and approving a new TPM? Describe and explain any variations to the process that you consider desirable.	<p>The high level process outlined on page 36 of the consultation paper appears broadly appropriate for the development of a new TPM subject to our comments below:</p> <ul style="list-style-type: none"> • there would be benefit in elaborating on the consequential Code changes and process for executing these • it may be prudent for the Authority to plan for additional consultation and to adjust its project plan and target implementation date accordingly. <p>Please refer also to our responses to questions 40, 42 and 43.</p>
3. Do you agree with the Authority’s view that the arrangements under the TPM for recovering connection costs are generally efficient?	<p>Yes.</p> <p>Under the current methodology, the aggregate value of all connection assets (\$136m for the 2013/14 year) is allocated to connected parties based on the types of assets they use. This pool-based approach means that customers’ charges are smoothed over time – for example, if a customer’s fully depreciated asset is replaced with a new asset, then the value of the connection pool increases but that customer’s share of the pool remains the same.</p> <p>This approach is consistent with the concept that connection asset customers are purchasing a level of service, rather than a specific set of assets. This approach also supports our ability to optimise capital and operating expenditure across our assets.</p>

<p>4. What comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs into the interconnection charge?</p>	<p>There is no evidence that there is a material problem to resolve.</p> <p>The issues paper describes two examples, provided by Transpower, where there is the potential for investment to cause an unintended reclassification of some assets from connection to interconnection. In the one case where investment has proceeded, we have agreed an approach that avoids this outcome.</p> <p>Rather than change to an untested approach of 'locking in' connection asset classification, the status quo should be retained.</p> <p>There is a risk that the proposed change could have perverse or unintended consequences if a situation arose where it legitimately made sense for assets to change from connection to interconnection.</p>
<p>5. Do you agree that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract?</p>	<p>In practice, no.</p> <p>We use pool-based connection charges for asset replacements that maintain a level of service, and project-based CIC charges for upgrades to capacity.</p> <p>There has not been a problem in practice with customers inefficiently avoiding CIC charges.</p> <p>The Authority may also be referring to a concern that costs may be shifted from the connection pool to the interconnection pool as part of a major grid investment. This is not our practice.</p> <p>The Authority may also be referring to the mechanism in the benchmark agreement that allows Transpower to ask the Commission to request us to propose a 'grid upgrade' on connection assets. This is a backstop mechanism to ensure GRS will not be compromised by a customer refusing to agree to an upgrade. In practice, this mechanism has never been used.</p> <p>The Authority also appears to be concerned that, if this mechanism were used, the customer would only fund a portion of the costs and that the balance would be funded through interconnection charges. This is incorrect. The historic building block values used to assess a customer's charges are only used as a way of allocating the connection pool. The overall size of the connection pool is based on the aggregate regulatory asset value of all connection assets. This means there is no material problem caused by building block values being lower than current replacement costs. Full connection asset costs are recovered from connection customers.</p>
<p>6. Do you consider that there are any other problems with the connection charging arrangements under the current TPM?</p>	<p>No.</p>
<p>7. What comments do you have about the Authority's analysis of the private benefits deriving from the HDVC link?</p>	<p>We comment in more detail on issues relating SPD analysis in response to later questions.</p> <p>However, we note that treating the HVDC as two discrete assets results in Pole 2, the 'first' asset, capturing the bulk of the benefits, while Pole 3 captures fewer benefits.</p> <p>This approach does not recognise the complementary nature of the poles – and the very significant reliability and other benefits that a bi-pole solution provides.</p>

<p>8. What comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges?</p>	<p>It is artificial to separate Pole 2 and Pole 3 charges and benefits in the manner described.</p> <p>We forecast that the 2016/17 revenue figures relating to the HVDC assets would be approximately \$24 million for recovery of historic EV balances, \$48 million for incremental costs of Pole 3, \$18 million for the incremental costs of upgrading Pole 2, and an addition \$70 million for operating costs and 'legacy' assets (for example, transmission towers, cables, and substation infrastructure).</p> <p>It is uncontroversial that South Island generators benefit from the HVDC link, but much more difficult to assess the extent to which their charges may exceed their private benefits in the long-run.</p>
<p>9. What comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge?</p>	<p>The \$30m PV estimate of costs associated with inefficient generation investment (Table 6 on page F10) and deferral of investment in peaking capacity appears to be largely based on TPAG analysis. We agree with the Authority (paragraph 3.3, footnote 4 of Appendix F and paragraph 296(a) in Appendix C appear to acknowledge this) that this estimate, and any analysis of this nature, carries considerable uncertainty.</p> <p>It is not clear what the Authority means by the comment: "at least in isolation". This could be taken to mean that in a broader context a different view may be formed about the cost or benefit of deterring new generation build in the South Island.</p> <p>Ultimately, the assessed PV depends on assumptions regarding demand projections, the relative costs and availability of generation expansion options, and the extent to which a generator or load party may alter investment decisions due to transmission charges. These are all uncertain, but we agree that the TPAG analysis is the best available guide.</p>
<p>10. What comments do you have about the Authority's analysis of the costs of inefficient operation of South Island generation resulting from the HVDC charge?</p>	<p>We agree the HAMI charge causes some inefficiency on the operation of South Island generation.</p>
<p>11. Do you consider that there are any other inefficiencies? Provide a detailed explanation of the nature and materiality of the inefficiencies.</p>	<p>No.</p> <p>However, the regulatory uncertainty created by near-continuous review of the HVDC charge by regulatory authorities may have an efficiency cost across the supply chain.</p>
<p>12. What comments do you have about</p> <p>a) the differences (including their materiality) between private benefits from interconnection assets and interconnection charges; and</p> <p>b) the consequences of those material differences?</p>	<p>The Authority has not demonstrated that there are material problems that would warrant a change.</p> <p>While more targeted beneficiary pays charges may be desirable in theory, there is value to a simple, forecastable, stable approach to recovering interconnection costs.</p>

<p>13. What comments do you have about the Authority's analysis of the problems with interconnection charges?</p>	<p>Refer to question 12.</p> <p>The Authority has not established a robust causal link between increased pricing-driven engagement grid investment processes, and better investment decisions.</p> <p>The Authority's preferred scenario ("Scenario B") on page D8 assumes that increased engagement (motivated by targeted charges) will result in the Commerce Commission deferring one in ten investment proposals by two years. The Authority then assumes that this deferral is beneficial.</p> <p>The avoided cost (or "benefit") of <i>efficiently</i> deferring an investment is equal to the avoided charges. For example, using a rule of thumb that annual charges are 10% of cost, the benefit of deferring a \$100m investment by one year would be \$10m. In practice, if the investment is early it will still deliver some benefits, which should be netted off when assessing the benefits of deferral. For example, an early investment still reduces system losses and congestion, and improves outage planning flexibility.</p> <p>The cost of deferring an investment <i>inefficiently</i> will be the cost of congestion and unserved energy.</p> <p>Given that the Authority's analysis appears to neglect the costs of inefficient deferral, and to neglect that inefficiently early investment still has some benefits, the estimates of \$20m to \$25m in the table on page D3 are too high.</p> <p>It is also not clear that there could be significant benefits due to "finding better transmission solutions". Grid investment already involves robust, multi-stage consultative processes for which finding the best available solution is a central feature.</p> <p>The Authority's problem definition work for the interconnection charge adopts a "diagnostic" approach. That is, the problems cited are often defined with reference to the Authority's specific proposal. This can lead to an incorrect problem definition and bias the analysis toward a particular solution. Rather, a proposal should be evaluated empirically – not legitimated by definition.</p> <p>For example, we do not agree that the fact that the current interconnection charge does not necessarily reflect the private benefits of consumers of the interconnected grid will result in on-going debate and lobbying which will be detrimental to the durability of the TPM (ref paragraph 4.4.6). On the contrary, the current interconnection charge is well understood and, with few exceptions, accepted by connected parties.</p>
<p>14. Do you consider that there are any other problems with the interconnection charging arrangements under the current TPM?</p>	<p>No.</p> <p>There is no evidence of material problems with the current interconnection charge regime.</p>

15. What comments do you have about the Authority's view that a prudent discount policy may be necessary after taking into account the incentives provided by the price components of any revised TPM?	We agree that the PDP will continue to be necessary.
16. What is your position on the Authority's proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals?	<p>We do not support this proposal because it would mute nodal pricing signals, which would reduce the efficiency of those signals.</p> <p>LCE should be rebated independently of the pricing process, as it is currently. This achieves the same end effect on customers, while avoiding the need to embed an additional monthly input into the price setting process.</p>
17. Do you agree there would be efficiency gains from each of the components of the proposal for the connection charge, as outlined in paragraph 5.4.9?	<p>No.</p> <p>The proposal creates more problems than the minor issues that it seeks to address:</p> <ul style="list-style-type: none"> • Customers would experience 'rate-shock' (going from a pool charge, to a new asset charge) when, to maintain service levels, we carry out end of life asset replacements. This may mobilise opposition to such replacements, which would hinder our ability to maintain services using rational asset management decisions. • Referral of disputes to the Authority would put the Authority back in the position of a second transmission regulator, which is counter to the intent of the reforms that led to its creation. The Commission already regulates expenditure on asset replacements. • 'Locking-in' connection asset status may unnecessarily restrict our ability to efficiency reconfigure the grid in future
18. Do you agree that the proposal will address the problem identified in chapter 4 in relation to the connection charge?	Refer to question 17.
19. What comments do you have about the Authority's assessment and conclusions about a kvar charge to recover static reactive support costs?	<p>We support the proposal to introduce a kvar charge where required, and to set a minimum power factor of 0.95 lagging in the connection code.</p> <p>Note that the charge has a cost-signalling objective rather than a cost-recovery objective.</p>

<p>20. Do you support:</p> <p>a) introducing a kvar charge based on off-take transmission customers' average aggregate kvar draw from the grid in areas where investment in static reactive support is likely to be required, at times of RCPD, at the long run marginal costs of grid-connected static reactive support investments?</p> <p>b) setting a minimum power factor of 0.95 lagging in the Connection Code for all regions?</p>	<p>Refer to question 19.</p>
<p>21. Do you consider that there are alternatives to a kvar charge for recovering the static reactive support costs that the Authority has not identified that are practicable, would deliver a net benefit and would recover static reactive support costs?</p>	<p>We support the proposed solution.</p>
<p>22. What comments do you have about the Authority's assessment and conclusion about charging options for dynamic reactive support?</p>	<p>The costs of these assets cannot be recovered using SPD charges. SPD would not reveal the impact of reactive power devices.</p> <p>We agree with the observation at paragraph 5.5.26, that the status quo is practical and efficient.</p>

<p>23. What is your view of the Authority's assessment and conclusions about using the SPD or vSPD model to establish a beneficiaries-pay charge for recovering some or all HVDC and interconnection costs?</p>	<p>The Authority's proposed SPD charge is an innovative approach to targeting charges at beneficiaries.</p> <p>We do not have any objection to aligning charges with beneficiaries in a workable and durable way: however the proposal as it stands raises concerns:</p> <ul style="list-style-type: none"> • The proposed charge involves <i>ex post</i> assessment of beneficiaries each half hour. In contrast to making a one-off assessment prior to investment, this encourages market participants to avoid charges by avoiding use of unconstrained transmission assets, which is inherently inefficient. • The charge would apply retrospectively to transmission investments back to 2004. Such broad retrospective application may undermine confidence in the predictability to future charges. • The charge would vary each month, and would not be known in advance. In conjunction with the charge being too complex for parties to accurately forecast, this approach would introduce new risks for generators, retailers and other purchasers. Parties would not have any ability to hedge this risk, and the risk would flow through to higher end consumer prices. The charge may reduce competition given it is likely to be particularly challenging for smaller retailers, generators, and purchasers. • The charge depends on complex model-based assessment of beneficiaries. This will significantly increase the risk of pricing errors, and will create contention over data inputs, and modelling approaches. There will be circumstances where the pricing operator is required to exercise discretion to obtain a solution, and this will invite dispute, as has occurred as with pricing outcomes using SPD in the wholesale market. • The full market system used by the System Operator is engineered for real-time processing rather than the batch processing required for monthly processing, and can also not be made available to customers. The Authority's vSPD is not revenue-grade software. For example, a pricing system requires robust auditable change controls, and systems to ensure continual alignment with the market system. As no existing system is suitable, a bespoke solution may be necessary. <p>As it has not been demonstrated that there are material problems with existing interconnection charges, we cannot see any reason to introduce an SPD charge that carries these risks.</p> <p>If the Authority decides to adopt an SPD charge for interconnection assets, then further development work is required to fully understand the likely consequences. The charge should:</p> <ul style="list-style-type: none"> • only be applied prospectively to interconnection assets • only apply to a limited number of the largest transmission investments • be calculated and set in a way that allows parties to forecast their annual charges.
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<p>24. Do you agree with the Authority's conclusion that the most efficient beneficiaries-pay charging option for applying to HVDC and interconnection costs is likely to be the SPD method?</p>	<p>No.</p> <p>Refer to question 23.</p>
<p>25. Do you consider that there are beneficiaries-pay options that the Authority has not identified that are practicable, would deliver greater net benefits and would recover HVDC and interconnection costs?</p>	<p>The current interconnection charge delivers stability and simplicity and is not inconsistent with a beneficiary pays philosophy.</p> <p>There are several potential options for recovering HVDC charges, including variations on the SPD approach. We encourage further work on determining the best approach, delivering a stable, simple and forecastable charge based on a one off assessment of beneficiaries.</p>
<p>26. Do you agree with the proposal to apply the residual charge to:</p> <ul style="list-style-type: none"> a. generators; b. direct-connect major users; c. distributors, except where they opt out from the charge; and d. retailers, were distributors elect to opt out from the charge? 	<p>The residual charge should be recovered from direct connect users and distributors.</p> <p>The only reason for this proposal is to reduce inadvertent price signalling by spreading the residual across more parties. This rationale is not compelling, because applying a charge to generators will <i>increase</i> unintended price signalling. Refer also to question 28.</p> <p>If distributors can opt out, then retailers are the logical alternative counterparty. We discuss issues with changing our customer mix in Section 3.3 of our submission. Our response to question 27 comments further on the proposal to permit distributor opt out.</p>
<p>27. Do you agree with the proposal that distributors may opt out from the residual charge:</p> <ul style="list-style-type: none"> a) to the extent that they do not benefit from offering interruptible load on the wholesale electricity market; and b) provided they consult with retailers that may be affected before they opt out? 	<p>Allowing distributors to opt-out only makes sense if purchasers are already exposed to transmission costs via the SPD charge, and if charges are set such that they are too volatile to be compatible with the price path regulation applying to distributors.</p> <p>Passing volatile charges to retailers will have a 'risk amplification' impact on end prices, and will make retail market entry and expansion more difficult for small players.</p> <p>Allowing distributors to opt out significantly alters commercial structures throughout the sector, and will have unintended consequences. For example, the commercial value of prudent discount agreements, distributed generation investments and demand-side investments would be seriously impaired by this change.</p> <p>Questions over the most appropriate counterparty for Transpower have been considered in depth previously – most notably by the Authority's predecessor in its review¹. The Authority should revisit the findings of that review.</p> <p>We discuss some practical implications of changing our customers in Section 3.3 of our submission.</p>

¹ See: <http://www.ea.govt.nz/our-work/programmes/transmission-work/development-of-the-benchmark-agreement/contract-structure-and-counterparties-preliminary-decision/submissions-for-preliminary-contract-structure-and-counterparties/>

<p>28. Do you consider that the proposed RCPD/RCPI charge, designed to encourage efficient avoidance of peak regional use of the grid, with half of the residual revenue recovered from load and half from generators, would best complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model?</p>	<p>It is important to be clear about the objective of the residual charge if applied in conjunction with the SPD charge. We understand from 5.6.71 that the Authority does not consider that the residual needs to incorporate price signals, but its proposal does not reflect this.</p> <p>We do not agree that the SPD charge, as proposed, would have the desired effect. It would therefore be necessary to retain the RCPD charge – which is designed to encourage efficient avoidance of peak regional use of the grid. However, it would not be beneficial to review the RCPD regions. The current demarcation is well understood by participants, and is not intended to provide tightly targeted pricing signals. Changing regions too frequently would undermine the credibility to the pricing signal that RCPD does provide.</p> <p>The only reason for the proposal to recover half the residual from generators is to reduce inadvertent price signalling by spreading the residual across more parties. This rationale is not compelling, because applying a charge to generators is likely to <i>increase</i> unintended price signalling.</p> <p>Generators are more likely than most consumers to alter their behaviour in an effort to avoid charges, and this is likely to reduce efficiency in the wholesale market.</p> <p>Overall we need a simpler, more limited set of charges. The large number of interacting charges is an undesirable feature of the Authority's proposals.</p>
<p>29. Do you agree that the RCPD/RCPI charge would best meet the principles for an alternative charging option of:</p> <p>a) minimising the distortion in use of the transmission grid resulting from the imposition of charges; and</p> <p>b) ensuring the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by concerns by investors that they will not receive a return on their approved investment?</p>	<p>In relation to part (a), refer to our response to question 28.</p> <p>In relation to part (b), if a fluctuating proportion of our revenues are recovered via SPD charges, then some 'residual' charging mechanism is <i>required</i> to ensure we recover our allowable revenues each month.</p> <p>This is not an optional feature of the pricing methodology given that the Commerce Commission regulates our revenue setting framework.</p>

<p>30. Do you agree that the Authority's preferred option for the residual charge should be an RCPD/RCPI charge designed to encourage efficient avoidance of peak regional use of the grid?</p>	<p>No.</p> <p>There should not be an RCPI charge.</p> <p>RCPD regions should not be revisited.</p> <p>We cannot identify any clear benefit from reviewing the RCPD regions. The upper North Island and upper South Island regions are regions with an on-going need for incremental transmission investment. The current demarcation is well understood by participants, and is not intended to provide tightly targeted pricing signals. Changing regions frequently would undermine the credibility to the pricing signal that RCPD does provide to optimise the timing of transmission investment and encourage non-transmission solutions.</p> <p>Regular changes to RCPD would deter investment in load control and distributed generation: however an appropriately designed mechanism could be developed that allows parties to understand the criteria that would apply to a gradual recalibration of the RCPD pricing signal, following a major investment, or to support further initiatives to reduce peak demand to defer investment.</p>
<p>31. What are your views about amending the existing prudent discount policy to provide that it:</p> <p>a) applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges; and</p> <p>b) may apply for the expected life of the asset to which the prudent discount applies?</p>	<p>The prudent discount policy should not cover notional disconnection.</p> <p>It is difficult to place a value on the various benefits of grid connection compared to self-supply. Grid connection generally allows a customer to readily expand their consumption, and provides reliability and quality benefits that self-supply is unlikely to match. It is difficult to determine an appropriate WACC for the annuity payment relating to a generation investment.</p> <p>We agree on (b).</p>
<p>32. Do you agree with the assessment of the economic costs and benefits of the Authority's TPM proposal versus the counterfactual?</p>	<p>The Authority's cost benefit analysis is not sufficiently robust to support the case for the proposed changes.</p> <p>In particular:</p> <ol style="list-style-type: none"> 1. The "top down" approach of multiplying an assumed efficiency parameter by estimated market revenues is highly subjective. 2. The analysis understates the transaction costs and opportunity costs to Transpower and the industry associated with developing and implementing the TPM proposal. 3. The analysis ignores the dynamic inefficiencies resulting from the proposed SPD and RCPI charges, and the reduction of the RCPD charge. 4. Rather than avoiding dispute, the proposal will increase dispute and lobbying. A complex model-driven pricing method with large wealth transfers will invite dispute. Unconstructive engagement in grid planning processes would increase planning and decision costs, and may delay efficient investment.

33. Do you agree with the assessment of the costs and benefits of the TPAG majority proposal against the counterfactual?	We note that the Authority has adopted different assumptions to the TPAG, but it is not clear what those assumptions are or why they differ. This appears to lead the Authority to select an efficiency factor more than four times greater than the TPAG majority proposal.
34. Do you agree that the Authority's TPM proposal meets the Authority's objective?	<p>The Authority describes its objective at paragraph 5.8.6 as to "facilitate efficient investment in the electricity industry and efficient operation of the transmission grid, generation (including distributed generation), distribution networks and demand-side management".</p> <p>This differs from the objective under the Code (at clause 12.78):</p> <p style="padding-left: 40px;">The purpose of the TPM is ensure that, subject to part 4 of the Commerce Act 1996, the full economic cost of Transpower's services are allocated in accordance with the Authority's objective to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers</p> <p>As administrator, we have an obligation to assess the TPM we develop against the Authority's (statutory) objective.</p> <p>We commissioned CEG to provide a high-level critique of the proposals from an economic perspective. The CEG report, which identifies serious concerns, is attached as Appendix B.</p>
35. What comments do you have about the Authority's evaluation of alternative market-based and market-like approaches for the recovery of transmission costs?	The alternative market-based and market-like approaches for recovery of interconnection and HVDC charges, as defined in table 10 on page 119, are not feasible within the existing framework.
36. What comments do you have about the Authority's acceptance of the TPAG's evaluation of alternative exacerbators pay approaches for the recovery of network reactive support costs?	We support the proposal to introduce a kvar charge where required, and to set a minimum power factor of 0.95 lagging in the connection code.
37. Do you agree with the Authority's assessment and conclusions about alternative beneficiaries pay options for establishing transmission charges to recover HVDC and interconnection costs?	<p>We consider that the Authority's conclusion, that each alternative approach creates grounds for disputes, applies equally to the preferred SPD option.</p> <p>In particular we agree with the Authority's observation at paragraph 6.5.9 that:</p> <p style="padding-left: 40px;">The main disadvantages [with using non-wholesale market models to apply beneficiaries pay are that] determination of the model and parameters are likely to involve significant dispute, accuracy of the determination of beneficiaries will depend on the model and assumptions used, and, depending on design, could affect offer behaviour.</p> <p>These disadvantages are not limited to non-wholesale market models.</p>

<p>38. Do you consider that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? Explain your answer.</p>	<p>The guidelines are a drafting instruction that draw heavily on the underlying policy decision. We prefer to consider submissions and to allow the policy process to run its course before commenting on the specific details of the guidelines.</p> <p>We have discussed with the Authority the need for a clear delineation between value impacting policy decisions which, where possible, should be made by the Authority and implementation design issues which should be made by Transpower.</p> <p>We consider that the current policy proposals create a number of policy design choices and global parameter choices that may materially affect the allocation of costs between different TPM charges and between the parties affected by each charge. In our view these decisions should be taken by the Authority.</p>
<p>39. Do you have any suggestions for amendments to the draft guidelines to ensure that they provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option?</p>	<p>Refer to question 38.</p>
<p>40. Do you agree with the Authority's proposed process that Transpower should follow in developing the TPM? Explain your answer.</p>	<p>The high level process outlined by the Authority for developing the TPM for submission to the Authority appears logical. The exception is the requirement in 8.2.7(a) for Transpower to include in the project plan a timeframe that would achieve the Authority's target of April 2015. We discuss timing issues in response to question 43.</p> <p>Refer to questions 42 and 43, and to section 3.1 of our submission for discussion of timing, costs and transition.</p> <p>The Authority should invest time upfront to ensure contentious policy decisions are addressed rather than deferring these to Transpower. We are concerned that the broader TPM process as currently anticipated will not provide sufficient opportunity to resolve the issues that have been identified with the proposed changes.</p>
<p>41. Do you agree that the Authority does not need to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated?</p>	<p>Yes.</p>
<p>42. Do you have any suggestions for amendments to the Authority's proposed process that Transpower should follow in its development of the TPM?</p>	<p>The Authority should remove or amend its proposed requirement for Transpower to include in its project plan for developing the TPM a timeframe that will achieve the Authority's April 2015 target.</p> <p>We will not yet have undertaken detailed implementation design work at that stage (we may be 12 months away from finalising the TPM), and the April 2015 target is unrealistic.</p> <p>Refer to question 43, and to section 3.1 of our submission.</p>

<p>43. Do you have any comments about the Authority's proposal that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year?</p>	<p>Refer to section 3.3 of our submission.</p> <p>From the time the Authority issues guidelines:</p> <ul style="list-style-type: none"> • a period of 12 months should be allowed for developing the pricing guidelines into full pricing rules. The process will be technically challenging, will require some critical design decisions, and customer engagement to ensure a robust product • a further period of 12 months of parallel operation (including providing customers with 'shadow' invoices) should be allowed. The pricing systems and processes will produce complex outputs (for example, a small retailer may have more than 3000 charge components per month²). Parallel operation will confirm the systems are operating correctly, while allowing customers to understand how their charges change over a year. <p>We consider 1 April 2017 is the practical implementation date assuming final pricing guidelines are available by June this year.</p> <p>This is our initial estimate and can be refined when there is a clear understanding of the final proposal.</p>
<p>44. Do you agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower?</p>	<p>We think that it would be beneficial to the industry if the Authority provides an earlier indication of when industry consultation is likely and the duration of that consultation.</p> <p>This will assist participants with resource planning but would not preclude extension or deferral if new information comes to light.</p>

² This assessment is based on charges for 64 SPD charge asset groups across 50 GXPs, plus RCPD charges for each of those GXPs (i.e. $65 * 50 = 3,250$ charges).

Appendix B – Competition Economists Group report



COMPETITION
ECONOMISTS
GROUP

Transmission Pricing Methodology – Economic Critique

February 2013

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Executive Summary

1. The Electricity Authority (EA) has proposed material changes to the Transmission Pricing Methodology (TPM). Most significantly, it plans to merge the high voltage direct current (HVDC) link and interconnection charges and to recover a proportion of the **required revenue from parties deemed to be ‘private beneficiaries’ of certain investments. Importantly, it proposes to use this ‘beneficiaries pays’ approach to set** prices for new assets and for investments made since May 2004 exceeding \$2 million. This already encompasses a significant proportion of the grid and, in time, will capture all of it.

General Observations

2. **The EA’s perceived problem with the current pricing arrangements** for HVDC and interconnection assets is that there is no direct link between those who benefit from a new investment and those who pay for it. Consequently, potential beneficiaries may have an artificially strong incentive to lobby for a new investment if they know that it is other parties (non-beneficiaries) that will ultimately bear the cost.
3. The proposed solution to this problem is to attempt to replicate the incentives that exist in well-functioning markets with clearly defined property rights. In workably competitive markets, beneficiaries are forced to pay for investments. This compulsion comes either through commitments that are made by foundation customers, or through competitive market prices subsequently being set to reflect the value that users place on the services provided by the relevant investment.
4. In such a market system, an investment will only be undertaken if the proponents have sufficient contracted demand for the service and/or are confident that future **users’ willingness to pay will be sufficient** to justify the cost. In other words, an investment will only take place if the present value of benefits to users (and hence their willingness to pay) is expected to exceed the cost of the investment. One way to attempt to achieve this outcome would be to institute a market-based process for initiating grid investments.
5. However, there are a number of reasons why attempting to deliver transmission investment through a market mechanism may not give rise to efficient outcomes (e.g., scale economies and difficulties in defining property rights - see Appendix A for more detail). Consequently, there is relatively little reliance placed on market based investment in electricity transmission sectors internationally, and nowhere is there sole reliance on this mechanism (at least, not as far as we are aware). The proposal is an attempt to deliver some of the benefits of a market based arrangement for investment without actually having such a system.

6. Specifically, it is proposed that all beneficiaries pay for an investment in proportion to the estimated *ongoing* benefits¹ that they derive from the existence of the asset over its life.² Under the proposal, beneficiaries will only have an incentive to lobby for an investment if the incremental benefits they anticipate receiving from it exceed their expected incremental allocation of total grid costs. Beneficiaries will have an incentive to lobby for the right investments if the methodology increases their total transmission charges by an amount that is proportional to their share of the benefits, multiplied by the total investment cost. Mathematically, this can be expressed as follows:

$$\begin{array}{l} \text{PV of expected} \\ \text{change in} \\ \text{transmission} \\ \text{charges for party } i \\ \text{consequent on} \\ \text{investment} \end{array} = \text{PV} \frac{\text{E(benefits of the investment to party } i)}{\text{E(total benefits of the investment)}} \times \text{E(investment cost)}$$

7. However, the proposed methodology may not create this efficient expectation of future cost allocations. This is not because of the informational difficulties associated with estimating potential benefits – although, these are great. The problem is more fundamental in nature. The difficulty is that the methodology does not simply allocate the cost of a new investment in a manner that reflects the benefits of that bespoke new asset. It also changes the allocation of the sunk costs of *past* investments. Specifically, **a new investment can be expected to alter a party's** allocation of total transmission costs due to:
- it acquiring a share of the costs of the *new* investment, based on the extent to which it is deemed to be a beneficiary of that asset; plus
 - any change in the allocation of the costs of *all other investments* that is brought about by the new investment, e.g., a new investment in one part of the grid may change the extent to which parties are deemed to be beneficiaries of *other parts of the grid*.
8. There can be no dynamic efficiency benefits associated with applying a ‘beneficiaries pay’ approach to reallocating the sunk costs of *past* investments. Sunk investment decisions have been made and there is now no way to reduce the cost or change the nature of those outlays. However, sub-optimal outcomes can be created through such reallocations, since they can result in large wealth transfers that may cause

¹ This assessment is not made on a ‘one-off’ basis upon commissioning (at ‘ t_1 ’). Rather, as the profile of beneficiaries changes over time (at t_2 , t_3 , t_4 and so on), so too does the nexus of private benefits and the quantum of transmission charges.

² Rather than having investors base their investment decision on a combination of firm contracts with users today and/or an assessment of future users’ willingness to pay.

market participants to act in ways that compromise both static and dynamic efficiency.

9. We are not aware of any transmission pricing arrangements that involve the perpetual reallocation of sunk costs. None of the international examples cited encompass such a practice. In fact, the US Court of Appeal decision that is discussed appears to caution against the practice.³ As we noted above, significant inefficiencies may result from such reallocations, including increased disputation (together with the associated costs), reduced wholesale market efficiency and a systemic increase in risk throughout the supply chain (see below).
10. These potential adverse consequences do not appear to have been wholly accounted for in the quantitative cost-benefit analysis. The \$173.2 million in net benefits said to be associated with the proposal is predicated on a belief that the proposal will promote dynamic efficiency. In our view, the opposite is quite likely to be the case. The failure to factor in the negative impact on incentives from continual reallocation of sunk costs renders the basic premise of the proposal questionable.

Greater Potential for Disputes

11. Under the proposals, once a new asset is built, this may change the way in which market participants pay for all of the other interconnection assets that have been built since May 2004 (that exceed \$2m). Moreover, day-to-day fluctuations in the wholesale market, changes in load profiles, and connections and disconnections will all affect the profile of private beneficiaries and, in turn, the transmission charges they are required to pay based on the Scheduling Pricing and Dispatch (SPD) model. These factors will increase the likelihood of disputes, because:
 - Market participants can be expected to view every new investment decision not simply on the basis of the direct costs and benefits of the asset in question, but on the basis of how that asset will affect their estimated benefits of every other part of the grid, and so the totality of their interconnection charges.
 - This means that the existing market participants may lobby for or against the construction of a new asset for reasons that have nothing to do with the direct costs and benefits of the bespoke investment but, rather, because they will **become ‘larger’ (or ‘smaller’) beneficiaries of the rest of the grid.**
 - In addition, because the interconnection charges that parties will pay will vary over time based on wholesale market outcomes, it is natural to expect that parties will perpetually agitate for changes to the SPD methodology that will serve to reduce their own transmission charges.

³ *Illinois Commerce Commission v FERC*, 576 F.3d 470, 476, pp.2-3.

12. The methodology is therefore unlikely to reduce the resources spent on lobbying and reviewing the methodology in the manner intended. Rather, it is more plausible that the scope for disputes will expand. In particular, introduction of the proposal may lead parties to advocate against efficient new investments (or for inefficient new investments) because they care primarily about the allocation of the sunk costs of *past* investments. This will harm dynamic efficiency.
13. One potential way of mitigating this last problem is to make a ‘one-off’ assessment of the beneficiaries of a new investment and require them to fund the investment in proportion to their estimated private benefit (either up-front or through ongoing annual fees). In other words, the perceived beneficiaries must commit to ‘writing a cheque’ (or a series of cheques) before the investment proceeds.⁴
14. Under this approach, once an investment is made, the parties that will pay for it have already been determined and **are ‘locked in’, even if the** market changes significantly in the future. Put another way, just as is the case in a market system, once costs have been sunk, so too is the responsibility for those outlays. It is only in these circumstances that parties will assess a new investment purely on the basis of their expected benefits and costs, in a manner consistent with workably competitive market processes (and the earlier formula).⁵
15. Of course, this would crystallise at the time of the investment what the proposal attempts to put off into the more distant future. Specifically, the allocation of benefits (via the running of a market model not just retrospectively each month, but out into the future over the life of the investment). Naturally, parties would still have a strong incentive to lobby on how that allocation is undertaken. But, if the modelling was accurate, they could be expected to only lobby for efficient projects (unlike the case where the modelling also reallocates sunk costs).
16. Of course, even here, dynamic efficiency would only be promoted if the estimation was accurate, i.e., if it reflected the true nexus of benefits. If it was not, then some parties may still have an incentive to lobby against/for investments that they perceived to be efficient/inefficient. Given the difficulties invariably associated with identifying beneficiaries, such an outcome is certainly conceivable.
17. There is also substantial scope for disputes to arise in relation to the way in which the SPD model is designed and implemented. For example, there are several inputs to the SPD model that have a significant effect on the incidence of charges, but which require a material degree of subjective judgement. These include (but are not

⁴ The beneficiaries identified today could also be given some rights over the extraction of value from future beneficiaries not currently in existence. Alternatively, the actual costs allocated to the beneficiaries identified today could be reduced by an estimate of the present value of benefits to parties not yet in existence.

⁵ As opposed to assessing a new investment based on the expected benefits and costs of that bespoke new asset *plus* the change in the allocation of all other costs.

limited to) the value that are assigned to unserved demand – **the ‘value of lost load’ (VoLL)**⁶ – and the time period over which benefits are estimated.⁷

18. The determination of these inputs may consequently attract particular scrutiny and controversy. The problem this creates is that there are **no ‘unambiguously correct’** values for these parameters – there is significant scope for legitimate disagreement. Parties can be expected to continually agitate for these aspects of the methodology to be changed, knowing that even a small change in their favour may significantly reduce their charges. Locking-in these inputs for a period – say, for five years – does not necessarily assuage this problem, because:
 - there would inevitably be significant dispute over the initial values assigned to these parameters, and the values assigned at each subsequent review – given the potential value at stake, those disputes could conceivably culminate in costly litigation (judicial reviews);
 - because the SPD model would have significantly more constituent parts than the existing TPM (an inevitable consequence of using a complex quantitative **model**), **there would be a wider ‘potential set’ of parameters over which** there would be controversy when the TPM was set/revisited; and
 - **the fact that the current TPM has been ‘set’ for** prolonged intervals has not insulated it from ongoing controversy, and so there is no reason to think that **‘locking-in’ VoLL, the capping period** and so on would prevent parties from constantly lobbying to have those parameters changed.
19. Moreover, as is often the case with sophisticated quantitative models, it is unlikely to be possible to fix every parameter in advance. Rather, we understand that Transpower will often need to make various ongoing judgements when defining **counterfactuals in order to ‘solve’ the SPD model. The nature and effect of these** judgements may vary depending upon the level of demand and other grid constraints (such as the location and availability of reserves). This constant (and unavoidable) recalibration creates an even more fundamental problem.
20. **Specifically, if Transpower must make a ‘judgement call’ in order to solve the model** during a trading period this may create **clear ‘winners and losers’ (as is frequently the case with transmission pricing). Whenever a party finds itself on the ‘wrong end’** of judgment call, it can be expected to challenge that decision. Moreover, because the methodology will eventually encapsulate the entire grid, the frequency of those disputes – and the sums in question – will only increase over time. This is a recipe for ongoing controversy.

⁶ *See:* Transpower, Electricity Authority TPM Proposal (2012) – **Transpower’s Modelling Work SPD, EA Modelling Workshop, Auckland, 4 December 2012, p.13.**

⁷ *See:* Transpower, *Electricity Authority TPM Proposal (2012) – Transpower’s Modelling Work SPD, EA Modelling Workshop, Auckland, 4 December 2012, p.12.*

Potential for Inefficient Grid Use

21. The New Zealand wholesale market design means that, most of the time, generation **plant should be ‘dispatched’ according to its economic merit order, as given by the** ascending short run marginal cost (SRMC) of running each type of plant. The incentives created for efficient, least-cost dispatch are a defining feature of a market that is widely acknowledged as being at the forefront of international best practice. The regional coincident peak demand (RCPD) based interconnection charge is also generally viewed as being a positive feature of the New Zealand arrangements.
22. The proposal risks compromising both of these aspects of the market – with the offsetting benefit intended to be the promotion of dynamic efficiency. If transmission charges were to be levied upon generators in the manner envisaged, this will increase the opportunity cost of generating, and may result in higher wholesale prices. To be clear, wholesale prices will be higher not just in absolute terms,⁸ but higher still than the level justified by that increased allocation.
23. **This is because the ‘private benefit’ based charge and the RCPI charge (depending upon its design) will be additional variable costs that may affect generator’s bidding conduct in the following inefficient ways:**
 - **The ‘beneficiaries pay’ charge** may cause generators to adjust their bids so as to avoid bearing a greater share of the sunk costs of past investments. When load can be served more cheaply by those generators, it is efficient for the pricing methodology to encourage the use of that infrastructure, not discourage it.⁹
 - Put another way, the proposal risks giving rise to a dispatch profile that no **longer represents the ‘true SRMC’ based merit order. The consequence is that** prices in the wholesale market will be higher in some parts of the country than if generators had not modified their conduct in this manner.
 - **Generators’ cash-flows** will also be less certain, which may result in additional risk premiums being incorporated in wholesale (and, in turn, retail) prices. The consequence is that prices in the wholesale market may be higher everywhere, regardless of whether generators engage in the above conduct.
 - The RCPI charge may create further distortions if it is not designed carefully. In particular, it may inflate further the additional risk premiums (described above) that generators may require to off-set reduced certainty of cash-flows. It may also weaken the beneficial incentives provided by the existing RCPD charge.
 - It may be possible to design the RCPI charge so as to mitigate those incentives and to preserve the existing properties of the RCPD charge, reducing the

⁸ Higher wholesale prices are an inevitable consequence of a greater allocation of grid costs to generators.

⁹ For example, in its paper, the EA acknowledges the possibility that generators might change their bidding conduct if its proposal is implemented. For example, it raises the possibility that South Island generators might bid so as to avoid being allocated the costs of Pole 3 of the HVDC link.

attendant distortions. However, even then, the charge seems not to offer any clear benefits, which is the relevant threshold for change.

- Different generators may also have different expectations about the precise quantum of additional transmission costs they will face through the **'beneficiaries pay' and RCPI charges**. They may therefore under- or, more problematically, **over**-estimate those costs when formulating bids.

24. In our opinion, one should not risk compromising the efficiency of the wholesale dispatch process in order simply to identify the private beneficiaries of a past (sunk) investment. **The perceived 'benefit'** – identifying and charging only those parties **that are 'private beneficiaries'** – is only a **'welfare neutral'** wealth transfer. In contrast, the higher wholesale prices that would result from generators adjusting their bids to avoid the incidence of sunk costs and to incorporate additional risk premiums are unambiguously harmful for consumers.

Risk Amplification

25. The proposal has the potential to amplify risk throughout the entire supply chain, with myriad attendant consequences. Generators will face additional risks since the methodology will **'marginalise'** costs that previously were either fixed (the HVDC charge), or recovered from off-take customers (interconnection charges). This will reduce the certainty surrounding their cash-flows and may result in higher, more volatile wholesale prices, for the reasons described above.
26. This has direct implications for electricity retailers who will be forced to pay those wholesale prices, as well as the separate SPD charges levied directly by Transpower. Both of these charges have the potential to be quite volatile, which will make it more difficult for retailers to forecast their input costs and to set retail tariffs – which are typically fixed for the course of a year. Retailers may respond to this uncertainty by incorporating additional risk premiums in their prices.
27. The heightened risk may also disproportionately affect smaller retailers. Larger retailers will often also own generation assets, and **those 'natural hedges' may** insulate them – if only to a degree – from wholesale energy price volatility.¹⁰ They **are also likely to have a greater stock of institutional capital ('know-how'), which**

¹⁰ These providers are sometimes called 'gentailers'. By owning both generation and retailing interests, a business may insulate itself to a degree from the risk of high/low spot market prices by being on **'both sides of the bet'**, i.e., although its retail arm may face a high wholesale price, its generation arm may be commensurately receiving that same high price (although that is not necessarily the case if there is nodal price separation and a generating unit is distant from the retail load).

they can draw upon in order to better predict peak periods, and factor that information into their prices.¹¹

28. Smaller businesses cannot address the heightened volatility through these means – and there is no way to hedge those risks through traditional financial instruments. These businesses may find it harder to enter the market and/or to expand if the proposal is implemented. This is potentially problematic because, although small retailers currently comprise only a modest share of the market,¹² they appear to have a significant disruptive influence on prices and service offerings.

Summary

29. The EA proposes substantial changes to the TPM in its paper. The most significant is its plan to merge the interconnection and HVDC charges and to recover a **proportion of the required revenue from parties deemed to be ‘private beneficiaries’** of certain investments. In our opinion, a robust foundation for that proposal has not been established. The following general observations can be made in relation to the proposed methodology:
 - The methodology will be applied primarily to reallocate the sunk costs of past investments, including the approximately \$2 billion of new investments that have been recently approved (much of which is now completed). This encompasses a significant proportion of the grid.
 - Those investment decisions have been made and there is now no way to reduce the cost or change the nature of those outlays. However, changing the way in which the sunk costs are allocated will result in large wealth transfers and may cause market participants to act inefficiently (see specific points below).
 - The potential adverse consequences associated with reallocating sunk costs are not accounted for in the quantitative cost-benefit analysis.
 - The cited international precedent does not support the re-pricing of past investments – in fact, the US Court of Appeal judgment cautions against doing so. More generally, we are not aware of any transmission pricing arrangements that resemble what has been proposed.

¹¹ Larger businesses may even be able to undertake load control during predicted periods of peak demand (e.g., switching off interruptible load) so as to reduce the quantum of transmission charges that they are assigned during those times.

¹² Currently, the largest electricity retailers and their subsidiaries (Contact/Empower, Genesis/Energy Online, Mercury/Bosco Connect, Meridian/Powershop and Trustpower) account for around 95% of the New Zealand market. (These shares are based on the percentage of energised installation control points (ICPs) held by each retailer as at November 2012. **See:** <http://www.ea.govt.nz/dmsdocument/14146>). The remainder of the market is made up of a number of small, independent retailers such as Tiny Mighty, Just Energy and King Country Energy (**See:** <http://www.switchme.co.nz/residential/power-companies.php>).

30. When one examines the particulars of the proposed changes to the interconnection and HVDC charge, the potential for inefficiency is even more apparent. Most notably:
- The proposal will increase the scope for disputes and in a manner that may lead some parties to advocate against efficient investments (or for inefficient investments) because they care primarily about the allocation of sunk costs. This will harm dynamic efficiency.
 - Parties can also be expected to perpetually agitate for changes to be made to the SPD methodology and to challenge any instances in which Transpower must make an **unfavourable ‘judgement call’ in order to ‘solve’ the SPD model**. This is a recipe for ongoing controversy.
 - **The ‘beneficiaries pay’ charge risks causing generators to adjust their bids so as to avoid bearing a greater share of the sunk costs of past investments, resulting in a dispatch profile that no longer represents the ‘true SRMC’ based merit order.** The RCPI charge may create further distortions if it is not designed carefully. The result in both cases will be higher wholesale prices.
 - Different generators may also have different expectations about the precise quantum of additional transmission costs they will face through the **‘beneficiaries pay’ and RCPI charges. They may therefore under-** or, more problematically, **over-**estimate those costs when formulating bids.
 - The proposal seems likely to amplify risk throughout the supply chain in a manner that is impossible to hedge against. The reduced certainty surrounding cash-flows is likely to manifest in generators (and retailers) incorporating additional risk premiums in their prices, regardless of whether they also engage in the above conduct (bidding to avoid sunk costs, etc).
 - The heightened risks described above also have the potential to affect the degree of retail competition – particularly that offered by smaller retailers without **‘natural’ hedges. The** proposal may mean that these types of businesses find it more difficult to enter the market and to expand once there.
31. For all of these reasons, the potential benefits associated with the proposal have been overstated and many of the costs understated or overlooked. The potentially substantial nature of these additional costs suggests that the methodology may in fact not offer any net efficiency benefits and may instead impose a net cost on the market, if it is introduced.

1 Introduction

32. This report has been prepared by the Competition Economists Group (CEG) on behalf of Transpower New Zealand Ltd (Transpower). Its purpose is to assist Transpower as it evaluates the **Electricity Authority's (EA's)** proposed revisions to the transmission pricing methodology (TPM). It provides a **relatively 'high-level' review of the EA's paper**¹³ and comments from an economic perspective on the integrity of the analysis contained therein, and the conclusions consequently drawn.
33. We focus particularly on the proposed changes to the charging arrangement for the high-voltage direct current (HVDC) link and for interconnection assets.¹⁴ The EA concludes that the HVDC charge is inefficient because:
- it discourages efficient investment in South Island generation, since it is only South Island-based generators that pay the charge;
 - it is not durable, since not all beneficiaries pay (e.g., North Island load) and, for those that do, charges do not necessarily equal private benefit; and
 - it encourages ongoing lobbying and reviews.
34. These observations are not new and are broadly accepted, e.g., the industry **Chief Executive Officers' (CEO) Forum and the Transmission Pricing Advisory Group (TPAG)**¹⁵ each made similar points in their recent reviews of the TPM (see Appendix A). **However, the EA's findings in relation to the interconnection charge – and its proposed solution – diverge considerably from the previous reviews.**
35. The EA concludes that the interconnection charge is inefficient because it does not promote either efficient transmission investment, efficient peak demand reduction or the efficient location of major new load. It consequently proposes to reform this aspect of the TPM together with the HVDC charge by:¹⁶
- collapsing the distinction between HVDC and interconnection charges, i.e., treating the two assets as indistinguishable for pricing purposes;

¹³ Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012 (hereafter: **EA Issues and Proposal Paper**).

¹⁴ The interconnection charge relates to the high voltage alternating current (HVAC) network, excluding connection assets.

¹⁵ **The TPAG was formed as part of the EC review (the EA's predecessor).**

¹⁶ It also intends to make some adjustments to the connection charging arrangements to 'close loopholes' and to modify the arrangements for network reactive support services. We have not considered these aspects of the charging arrangements in this report.

- funding interconnection and HVDC transmission services through the loss and constraint rentals generated by spot market differentials throughout the grid¹⁷ (a **‘market-based’** charge); and
- because the loss and constraint rentals cannot fully fund the services in question (because of scale economies¹⁸ and the understandable tendency to invest earlier rather than later¹⁹), it intends to recover the residual by:
 - setting prices for HVAC and HVDC assets based on its interpretation of a **‘beneficiaries pay’ pricing principle and applying those charges to off-take customers and generators alike (a ‘beneficiaries pay’ charge)**; and
 - recovering the remaining residual²⁰ from off-take customers (based on their contribution to regional coincident peak demand, or RCPD) and generators (based on their regional coincident peak injections, or RCPI), in a **50:50 split (an ‘alternative charging option’)**.

36. The methodology is based on the **‘hierarchy of approaches’** contained in the EA’s decision-making and economic framework paper.²¹ However, rather than picking a single option, the EA attempts to **‘take what it can’ from each option, before moving to the ‘next rung’ in the ladder**. The resulting methodology therefore contains a collection of different pricing principles. The proposed interconnection/HVDC charge is not a market-based, beneficiaries-pay, or a **‘postage-stamp’ price**. Rather, it includes aspects of all of these principles.
37. Integral to **the EA’s** methodology is the Scheduling, Pricing and Dispatch (SPD) model that is currently used to determine prices and quantities at the 220 nodes in the wholesale market. It proposes to identify the beneficiaries of past (post May 2004) and future grid investments by applying the SPD model to selected assets and allocating the costs to beneficiaries in proportion to their share of private benefits. It

¹⁷ These rentals could accrue to Transpower or, in principle, to the owners of financial transmission rights (FTRs) for the infrastructure in question.

¹⁸ There are strong economies of scale associated with new transmission investments because, once the land has been procured and the towers constructed, there is not much difference in cost between a high capacity line and a lower capacity line. This means that, once built, transmission lines eliminate congestion, and so any congestion rents.

¹⁹ Given the importance of the transmission grid from a security of supply perspective, there is an understandable tendency to err on the side of prudence when constructing transmission lines and build earlier rather than risk the consequences of building too late.

²⁰ The EA recognises that there is likely to still be unrecovered costs even after parties are charged in proportion to their private benefit.

²¹ Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Consultation Paper*, 26 January 2012 (hereafter: ‘EA Consultation Paper’) and Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Decisions and reasons*, 7 May 2012 (hereafter: ‘EA Decisions and Reasons Paper’).

intends to do so by comparing various wholesale market outcomes in which certain elements of the grid are removed.

38. If implemented, the proposal would represent a substantial departure from the existing TPM. We are not aware of any arrangements quite like it and, as we explain subsequently, the examples cited from other markets are not comparable. Transpower is therefore understandably interested in obtaining an independent review **of the EA's analysis**. We provide this in the remainder of this report, which is structured as follows:
 - **section two** sets out some general observations on the proposal, including the way in which the EA applies its hierarchy of approaches, the timing of its proposal, the limitations of its quantitative cost-benefit assessment and the applicability of the cited precedent;
 - **section three** explains why the proposal is unlikely to reduce the scope for disputes and ongoing lobbying in the manner intended, and may instead lead to dynamic efficiency losses rather than dynamic efficiency gains;
 - **section four** explores the ways in which the proposal could compromise the efficiency of the wholesale spot market dispatch process by causing generators to adjust their bids so as to avoid the incidence of transmission charges, resulting in higher spot prices; and
 - **section five** explains why the proposal has the potential to amplify risk throughout the entire electricity supply chain and make life much harder for **smaller retailers that do not have 'natural hedges'**.
39. We have also set out some additional material in two appendices. Appendix A provides a brief history of transmission pricing in New Zealand, in which we recount the key findings of the several recent reviews that have been undertaken of the TPM. Appendix B contains a worked example from outside the transmission sector that illustrates the potential shortcomings associated with setting prices for a service based on a changing profile of beneficiaries.

2 General Observations

40. **In this section we set out some general observations about the EA’s overall approach** and the analysis that it has undertaken to arrive at its proposed methodology. We consider the way in which it has applied its hierarchy of approaches, the timing of the proposed changes, the limitations of its cost-benefit assessment and the relevance of the precedent that it provides. We examine the more specific elements of the proposal in more detail in sections three to five.

2.1 Hierarchy of Approaches

41. The EA says that it has arrived at its methodology by working through the hierarchy of approaches contained in its earlier decision-making and economic framework papers. A number of the submissions pertaining to that paper questioned the practicality of the proposed framework. In particular, a recurring proposition was that **‘market-based’ and ‘beneficiaries-pay’** charges could have only limited application to transmission services.²²
42. Most submitters appeared also to be under the impression that if a market-based charge, or a beneficiary- or causer-pays charge could not recover 100% of the costs **of the relevant service then, under the EA’s hierarchy, the ‘next best option’** would be considered. Most took that to mean that there was consequently very limited scope for such approaches to be applied to interconnection assets. However, the EA takes a rather different approach to selecting its preferred option in its latest paper.
43. The EA accepts that, for HVDC and interconnection assets, it cannot select any of its **‘top three’ choices in their own right**. However, instead of ‘going down the list’ **to an** alternative charging option (such as the transitional postage stamp option favoured by the majority of the TPAG), it decides instead to implement each of its preferred approaches to the fullest extent possible. The resulting methodology therefore brings together a collection of different pricing principles, and is far more complex than the current TPM.
44. **In our opinion, there is not necessarily any reason to think that some ‘market-based’ and ‘beneficiaries-pay’ charging is better than none** – particularly if it involves bringing together a number of different pricing principles, as the proposal in question does. One must consider how the plethora of concepts that make up the interconnection charge will interact with one another, and the incentives this will create for the parties that they are levied upon.

²² The EA acknowledges this in its EA Decisions and Reasons **Paper when it observed that: ‘...many raised issues about the application of the framework, with some suggesting that this implied the framework was unlikely to be practical’.** See: EA Decisions and Reasons Paper, paragraph 9.

45. The fact that the pricing methodology will be applied largely to past investments makes this reconciliation even more critical. Because the proposal changes the allocation of sunk costs, it involves large wealth transfers and carries a risk of inefficient incentives and unwelcome distortions (which we explore in sections to come). Moreover, given that Transpower has just completed a new investment program, it would seem to be an especially inappropriate time to be contemplating major changes to that way in which those sunk costs are recovered.

2.2 Timing of the Proposal

46. The EA states (and we agree) that the TPM should focus on the overall efficiency of the electricity industry for the long-term benefit of electricity consumers. The achievement of this objective involves facilitating the efficient investment in and use of the grid, generation (including embedded generation) and demand-side **management**. **The EA's** reasons for revisiting the TPM and proposing the changes that it does are that:²³
- over \$2 billion worth of transmission investment has been approved – by the EC before November 2010 and by the Commerce Commission since that time, including the HVDC pole 3 and the North Island grid upgrade – and the costs of those investments must be recovered under the TPM;
 - there have been significant changes to the regulatory framework, with the EA replacing the EC from 1 November 2010, and the function of approving major grid investments being transferred to the Commerce Commission; and
 - advances in technology and the reducing costs of computational power have made available more sophisticated means of allocating transmission costs.
47. In our opinion, setting aside the particulars of the proposal (which we consider subsequently), these do not seem to us to be compelling rationales for proposing a substantially different approach for setting HVDC and interconnection charges. The TPAG and the CEO Forum were cognisant during their reviews of the fact that simply reallocating sunk costs risks much for little reward (see Appendix A for more **detail**). **In contrast, the EA's seems not to have given as much attention to this trade-off in formulating its proposal.**
48. Moreover, now that Transpower has had over \$2 billion of investment approved (much of which is now completed), there is limited benefit from significantly changing the way those costs are recovered, since:
- the \$2 billion is, for all intents and purposes, a sunk cost;²⁴ and

²³ EA Issues and Proposal Paper, paragraph 2.3.9.

²⁴ It was also perceived to be beneficial and that assessment was made based on generation and load patterns forecast under the current TPM.

- the investment decisions have been made and there is no way now to reduce the associated fixed costs.

49. Looking forward, there are considerably fewer major new transmission investments on the horizon.²⁵ The EA appeared to acknowledge as much in its earlier decision-making and economic framework paper.²⁶ In examining an earlier proposal of the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) – a proposal that resembles in some important respects that which the EA has now proposed (see further discussion in Appendix A) – it observed that:²⁷

“[M]ost of the grid upgrade expenditure likely to be required in the next few years has already been approved by the Electricity Commission. As a result, adopting the approach of TWG would not have much impact on transmission charges for a significant period of time.”

50. However, recalibrating the allocation of those sunk costs has the potential to provide inappropriate incentives and reduce static and dynamic efficiency, as we explain in the sections ahead. In other words, the benefits are unclear, but the potential costs are immediately evident. Orthodox economic principles suggest that because such a substantial sum has been invested recently by Transpower (and that future investment needs are far less extensive) it is a good time to **abstain** from making major changes.
51. In addition, it is not clear why the Commerce Commission assuming responsibility for approving grid investments should prompt substantial changes to the TPM. In fact, it heightens the risk of inconsistencies emerging between the two frameworks **when the new grid approval process is just ‘bedding in’**. Similarly, even if advances in computational power in recent years have indeed opened up new pricing options, more complex allocation methodologies are not necessarily superior.
52. For these reasons, we find it hard to escape the conclusion that, if **one’s** objective is to incentivise the efficient investment in and use of infrastructure, and a large investment program has been recently completed, re-pricing those assets is an intrinsically risky exercise. The potential efficiency gains are not obvious, but the potential costs are clear, as we set out in more detail in sections three to five.

²⁵ See: <https://www.transpower.co.nz/projects>.

²⁶ Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Consultation Paper*, 26 January 2012 (hereafter: ‘EA Consultation Paper’) and Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Decisions and reasons*, 7 May 2012 (hereafter: ‘EA Decisions and Reasons Paper’).

²⁷ EA Consultation Paper, paragraph 4.3.17.

2.3 Cost Benefit Methodology

53. The Issues and Proposals Paper includes a variety of calculations that purport to demonstrate the relative costs and benefits of the various pricing options that have been considered. However, the \$173.2 million in net benefits said to be associated with the proposal is simply a product of the assumptions employed in its modelling. To arrive at the estimate, total sector revenue²⁸ (based on assumed growth rates) is multiplied **by an ‘efficiency parameter’** (determined based on various qualitative information²⁹) and a discount rate (of 6.01% real).
54. The efficiency factor that has been applied is 0.3% of total revenue. This is equivalent to a \$0.12/MWh (or 0.05%) reduction in the average unit price per MWh (over total volumes).³⁰ This efficiency factor is not estimated; it is **assumed**. Taking a lower (higher) parameter will reduce (increase) the estimated economic benefits. Similarly, applying a **negative** parameter will result in a net economic **cost**. The magnitude of this parameter is ostensibly justified through a series of qualitative assessments. However, none of these analyses can provide any real insight into the appropriateness of the assumption.
55. The first assessment that is undertaken is a comparison between the assumed efficiency parameter and the long run total factor productivity (TFP) growth rate that has been applied by the Commerce Commission to determine the default price-quality paths for electricity distribution businesses. However, these two factors are not measuring the same thing and the comparison therefore cannot reveal anything meaningful about the robustness of the assumed efficiency parameter.
56. An examination is then made of the metrics contained in reports by the Electric Energy Market Competition Taskforce and PA Consulting. However, these also are of questionable significance, since they are, again, measuring quite different things. **The ‘avoided generation cost’ example is also unhelpful.** The example suggests that if the proposal avoids significant future generation costs, then its benefits will exceed those implied by the efficiency parameter. However, if those costs are not avoided (and no material is presented to show why they would be), or if future generation costs are higher, then the opposite will be true.
57. The EA is quite correct that measuring efficiency benefits is difficult. It is also the case that New Zealand courts have accepted similar approaches in the past – albeit in different contexts. However, neither of these points detract from the basic problem that there is no principled basis for the efficiency parameter or, in turn, for

²⁸ **The size of the electricity market is estimated by multiplying each sector’s volume (i.e., industrial, commercial and residential) by its final price.** Market prices are expressed in constant 2011 dollars. **See:** EA Issues and Proposal Paper, Appendix F, paragraph 3.12.

²⁹ EA Issues and Proposal Paper, Appendix F, paragraph 3.7.

³⁰ EA Issues and Proposal Paper, Appendix F, paragraph 3.15.

the purported quantum of benefits. The 0.3% value **simply reflects the EA's belief** that its proposal will deliver significant economic benefits when, for the reasons we set out in sections three to five, there is good reason to think that it will not.

2.4 Appeal to Precedent

58. The EA states that the beneficiaries-pay approach to transmission charging is emerging as 'common practice' internationally. It cites four examples to support this proposition: a recent decision of the US Court of Appeals in the PJM market, and arrangements for approving grid investments in Argentina, New York and New Zealand. In our opinion, four cases do not establish a **'common international practice'** and, even if they did, the examples bear little resemblance to what has been proposed.
59. The US Court of Appeal in the PJM matter ruled that the regulator (FERC) should not have required grid users to pay prices for new investments that exceeded significantly the private benefit they obtained. However, a defining characteristic of the proposal in this instance is the application of a beneficiaries-pay principle to ***past*** (as well as new) investments. If anything, Justice Posner cautioned against reallocating sunk costs in this manner in his judgment. This is evident in the following extract, which we have reproduced in its entirety:³¹

"PJM wants that transmission to be priced on the basis of the cost to American Electric of transmitting one more unit of electricity, that is, the marginal cost; and FERC agrees. Such a price excludes the cost that the company incurred when it built the transmission facilities. That cost – which American Electric wants to be permitted to reflect in its rates – is what economists call a "sunk" cost, that is, a cost that has already been incurred. So while its financial burden can be shifted (from American Electric to the eastern utilities), the cost itself cannot be shifted, and therefore shifting the financial burden created by the cost from one set of shoulders to another will have no direct effect on service or investment.

Had FERC decided that American Electric would not be permitted to charge a price that covered the cost of building a new transmission facility or upgrading an existing one, its decision would have affected the allocation of resources and not just money. It would have deterred the building of new facilities that benefited customers outside American Electric's service area, because building them would become an unprofitable venture. FERC emphasizes, however, that the company's existing facilities, which are all that are involved in this case, were built before 2001 when PJM became a Regional Transmission Organisation, and were intended to serve American Electric's customers only. So even if the facilities had not been fully paid for,

³¹ *Illinois Commerce Commission v FERC*, 576 F.3d 470, 476, pp.2-3.

there would be no economic basis for shifting any part of the costs to other members, because American Electric did not expect when it built the facilities that any part of their cost would be defrayed by anyone besides its customers.”

60. The preceding paragraph serves to highlight the basic problem that beneficiaries change over time. It is one thing to look, as the court did, at the beneficiaries of a new investment and make a judgement at that time about the relativity of prices and benefits at a particular point **in time**. It may even be possible to ‘lock-in’ the prices that will apply to a new investment at the time that it is made, based on the then current profile of beneficiaries.³² However, applying a ‘beneficiaries pay’ approach to set prices for **past** investments is an altogether different proposition.
61. The **EA’s** proposal is to charge parties based on who is perceived to be benefiting from (past and present) interconnection and HVDC assets **today**. That is not what the court is suggesting should be done. If one were to attempt such an exercise, the above passage suggests **that the relevant question would not be “who are the beneficiaries now?” but; rather, “who were the beneficiaries expected to be at that time over the life of the assets?”** Even if that exercise were possible (which is unlikely³³), it would not be advisable.
62. Indeed, like the TPAG and the CEO Forum (see appendix A), Posner acknowledges that, although the financial burden of a **past sunk cost can be shifted from ‘one set of shoulders to another’**, the cost itself is unavoidable, and the reallocation will have no direct effect on service or investment. In other words, the judgment appears to be cautioning against what has been proposed in relation to interconnection and HVDC charges.
63. The other examples are also inapposite. Between 1992 and 2001, major transmission expansions in Argentina were **subjected to a ‘vote’ and**, before they could proceed, at least 30% of the beneficiaries were required to support the proposal and no more than 30% of the beneficiaries could be opposed. A similar regime exists in New York, where a regulated transmission investment requires the support of a supermajority (80%) of beneficiaries. One can debate at length the merits of these arrangements,³⁴ but the essential point is that these are all examples of different ways to decide/fund **new** transmission investments:

³² For example, *see*: Hogan, WW, **Transmission benefits and cost allocation**, Mossavar-Rahmani Center for Business and Government, John F. Kennedy School of Government, Harvard University, May 31, 2011. As we explain in more detail in section four, this requires difficult long-term judgements to be made about future grid use patterns and investments, etc.

³³ The substantial problems associated with such an exercise are described in more detail in section 4.1.

³⁴ The EA cites a paper that argues that the Argentinean arrangements were a success, but many other commentators have deemed them a failure. For an overview of these critiques, *see*: Littlechild, SC and Skerk, CJ: **“Regulation of transmission expansion in Argentina Part I: State ownership, reform and the fourth line”**, CMI EP 61, 2004, p.5.

- none of the arrangements mentioned above involve reallocating the sunk costs of past investments in the fashion contemplated by the proposal; and
 - more generally, we are not aware of any transmission pricing arrangements that do so and it is not a foreseeable trend.
64. The methodology developed by the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) is also not relevant. First, like the Argentinean and New York examples, the proposal related only to new investments – it did not involve reallocating the sunk costs of past investments. Second, as we explain in more detail in Appendix A, the proposed arrangement was ***rejected*** by a majority of the industry in 2002 and, when the ***Electricity Governance Rules*** (which contained the regulatory TPM) were introduced in 2003, an administrative process was favoured.
65. It has therefore not been established that the proposal is consistent with common international practice, or even a foreseeable trend. None of the examples cited involve the reallocation of sunk costs – if anything, the US Court of Appeal decision appears to caution against the practice. Moreover, the New Zealand TWG EGEC example is a case study in which the majority of the industry and the government of the day rejected a proposal to apply a market-based approach to undertaking new transmission investments, favouring instead an administrative process.

3 Greater Potential for Disputes

66. In this section we illustrate why we believe that the proposals are unlikely to reduce the scope for disputes and lead to a more efficient investment process. In our opinion, the opposite outcome is more probable. Specifically, the proposed approach for establishing interconnection charges is likely to broaden the scope for disputation and harm dynamic efficiency.

3.1 Rationale for the Proposal

67. Before Transpower can undertake a major new capital investment, it must satisfy the Investment Test set out in its Capital Expenditure Input Methodology (IM), administered by the Commerce Commission. To meet that test, a proposed **investment must (amongst other things), have the highest ‘expected net electricity market benefit’**.³⁵ The focus is therefore on ensuring that new investments maximise the net market (as opposed to private) benefit. The Grid Investment Test (GIT) previously administered by the EC had an equivalent emphasis.
68. It has not suggested (at least not explicitly) that this IM is incapable of delivering the right investment outcomes. There also appears to be no suggestion that Transpower has, in the past, built ‘the wrong assets at the wrong times’.³⁶ Rather, the proposal is ostensibly targeted at the **process** by which investment decisions are made. It has been contended that, under the current manifestation of the HVDC and interconnection charges, some parties may have weak incentives to advocate for/against only efficient/inefficient transmission investments.
69. This is said to be because there is no direct and proportionate link between the beneficiaries of an investment (i.e., the parties most likely to agitate for it) and the parties that pay for it. This, in turn, is claimed to lead to ongoing lobbying, contention amongst industry participants and the inefficient use of, and investment in, transmission assets. For this reason, even if the right investment decisions are ultimately made (and no material is presented to suggest that this has not been the case), time and money is still wasted on lobbying and disputation.
70. The EA suggests that its SPD-based methodology will be a durable way of identifying and levying private beneficiaries that will reduce disputes and prevent the beneficiaries of an uneconomic project from lobbying for it to proceed simply because the costs will be smeared across other users. It therefore contends that its

³⁵ Commerce Commission, *Re Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, 31 January 2012, Schedule D1, p.53.

³⁶ For example, the EA does not seem to question directly the efficiency of the \$2 billion in investments that was approved recently.

proposed interconnection charge will promote dynamic efficiency.³⁷ The source of **those efficiency benefits is not necessarily ‘better investment outcomes’** (as noted above, the outcomes may ultimately be the same) but, rather, a superior investment **process** that avoids the costs of disputes.

71. It is certainly true that if parties know they will be required to pay a price for a new asset that is proportionate to their expected private benefit, they will have an incentive to advocate for the right investments at the right time. Moreover, for **certain types of transmission assets a ‘causer’ or ‘beneficiary’ pays approach is** relatively straight forward to put in place. Connection assets are an example. If a generator wishes to connect to the grid and will be the only party using the asset, it will be only be prepared to fund the investment through connection prices if its private benefits exceed the costs it will face.
72. However, even with connection assets, complexities can arise over time if there is a **non-zero probability that other parties will connect and ‘share’ existing assets.** For instance, if a second generator comes onto the scene several years later and wishes to connect to an existing spur, the marginal cost of hooking up that second-mover may be very low. This raises a number of difficult questions:
 - Should the second-mover, which is now clearly benefiting from the transmission line, pay a price that reflects the marginal connection cost or should it be required to pay a greater share of the sunk costs – thereby reducing the burden on the first mover?
 - If the latter, should the first mover have the ability, within defined regulatory bounds, to negotiate the level of contribution made by second movers, recognising that this will impact on the incentives for the initial investment and/or subsequent investments?
73. These are not straightforward issues and serve to highlight one of the greatest challenges with applying causer- and beneficiaries-pays principles to transmission assets. That is that the benefits of transmission investments are spread over time **and often in a complex fashion. Today’s beneficiaries may not be tomorrow’s.** In its report to the CEO Forum, NERA observed that,³⁸ although the current connection charging approach provides a locational signal to connecting parties of the costs of their decisions – albeit an imperfect one – the potential for distortions remains:³⁹

³⁷ As we noted above, this belief appears to be one of the central reasons for adopting the 0.3% efficiency parameter in its cost-benefit analysis that yields the estimated \$173.2 million in net economic benefits (in NPV terms over 30 years).

³⁸ The potential complications arising from these issues are canvassed in some detail in the NERA report prepared for the CEO Forum, **see:** NERA Report, pp.44-54.

³⁹ NERA Report, p.54.

“[B]ecause connection charges can vary substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment signals can be created in some circumstances. In addition, the arrangements for recovering the costs of ‘shared’ connection assets may give rise to significant step-changes in connection charges as ‘beneficiaries’ change over time, which can reduce certainty and further harm dynamic efficiency.”

74. In other words, it is challenging even to apply causer- and beneficiaries-pays principles to connection assets. These difficulties are exacerbated considerably if one seeks to apply a beneficiaries-pay principle to interconnection (and HVDC) assets in the manner proposed. Investments in such assets exhibit long lives, significant economies of scale and substantial interdependencies with existing **interconnection assets (it is, after all, a ‘shared grid’)**. It is a complex and controversial exercise to identify the beneficiaries of such assets at a **point** in time, much less over their entire lives, during which time the nexus of benefits can change dramatically.
75. However, if one were to attempt such an exercise there are, broadly speaking, two ways of going about it. The first is to seek to identify who the beneficiaries are **expected to be over the life of an asset and to ‘lock-in’ the charges over the period** to recoup the investment costs. The second is to perpetually change the profile of charges as beneficiaries change over time – this is the approach that has been proposed. As we explain below, neither approach would be likely to reduce materially the costs of disputes in the manner intended.

3.2 ‘Locked-in’ Beneficiaries

76. The first way to apply a ‘beneficiaries-pays’ approach to pricing an interconnection asset is to estimate the expected future private benefits to parties over its life – measured at the point in time at which the investment is made. The resulting **charges are then ‘locked-in’, so that the beneficiaries identified at that particular reference point continue to pay those prices over the lifetime of the asset** (the parties might also be issued FTRs or some form of property right in return for the funding).⁴⁰ The quantum of private benefits might be forecast using transmission planning and dispatch models.
77. Hogan (2011) suggests such a methodology – although only for **new** transmission investments.⁴¹ The principal advantage of such an approach is that, by fixing the

⁴⁰ Issuing FTRs would present an array of additional practical challenges that would need to be overcome. A summary of the steps that would need to be undertaken to introduce FTRs is provided at pages 105 to 106 of the NERA Report.

⁴¹ Hogan, W. W, *Transmission benefits and cost allocation*, Mossavar-Rahmani Center for Business and Government, John F. Kennedy School of Government, Harvard University, May 31, 2011.

charge in advance of the investment, parties cannot alter their behaviour to avoid the charge, which promotes static efficiency. However, even if this (or a similar) methodology is limited to new investments, several drawbacks exist – some of which are highlighted in the Issues and Proposals paper,⁴² including:

- it is impossible to forecast with any real precision the temporal dynamics of private benefits over the 30-50 year (or thereabouts) life of an interconnection asset – **any such exercise would swiftly become a ‘battle of competing models’**, as parties sought to demonstrate that they were not going to benefit to the degree forecast by the transmission planner; and
- **because parties’ actual benefits may differ from their anticipated benefits, they may end up paying for assets from which they do not benefit, which is likely to make them more likely to agitate against investments from which they may very well benefit, simply because they fear the possibility of being subsequently burdened with a disproportionate share of the costs.**⁴³

78. For these reasons, even if this (or a similar) approach is applied only to *new* investments in interconnection assets, the potential for distortions is considerable. This would be unavoidable **given the fact that this assessment would decide “once and for all” who was going to pay for the asset.**
79. Seeking to apply the approach to *past investments* would entail even more controversy. If one were to attempt such an exercise (which is clearly not intended), it would be necessary to look back at every investment since May 2004 (the cut-off date proposed by the EA) and ask: **“who were the beneficiaries expected to be over the life of that asset *at the time that the investment was made?*”** This would be a complex (perhaps impossible) thought experiment.
80. Moreover, it is not clear what such an exercise would achieve since, as we have explained, shifting the financial burden of past sunk costs does not offer any obvious efficiency benefits, and risks giving rise to unintended consequences. In other words, locking-in prices for a defined class of beneficiaries over the life of an investment is a fraught exercise that would increase scope for disputes and risk many distortions.
81. The proposed methodology might be thought of as addressing these problems by putting in place a process that continually revisits the estimation of the beneficiaries as circumstances change over time. One might expect that this would therefore remove some of the uncertainty and controversy that would be associated with the **“one off” estimation of beneficiaries. However, that** is unlikely to be the case.

⁴² EA Issues and Proposal Paper, paragraph 6.5.5.

⁴³ *Ibid.*

3.3 Ever-changing Beneficiaries – the Proposed Approach

82. The proposed methodology seeks to identify the beneficiaries of past (post May 2004) and future grid investments by applying the SPD model to selected assets and allocating the costs to beneficiaries in proportion to their share of private benefits. It does so by postulating various hypothetical wholesale market outcomes in which certain elements of the grid are removed. In this way, the identity of beneficiaries – and the prices that they pay – will *vary over time* as grid usage patterns change and new investments are made.
83. It is suggested that charging a changing pool of beneficiaries represents the most efficient means of **applying the ‘beneficiaries pay’ principle**. It is said that the methodology will be more durable and subject to less controversy, because the charges applied to parties for interconnection assets will reflect the benefits that they obtain from investments over time. This will ultimately promote the more efficient use of and investment in transmission grid infrastructure.⁴⁴
84. However, beneficiaries will only have an incentive to lobby for an investment if their incremental benefits exceed the incremental total grid costs that they will be allocated. Mathematically, the methodology will provide beneficiaries with efficient incentives to agitate for/against new investment if:

$$\begin{array}{l} \text{PV of expected} \\ \text{change in} \\ \text{transmission} \\ \text{charges for party } i \\ \text{consequent on} \\ \text{investment} \end{array} = \text{PV} \frac{\text{E(benefits of the investment to party } i)}{\text{E(total benefits of the investment)}} \times \text{E(investment cost)}$$

85. It is true that, compared to the ‘one-off’ approach described above that the proposed approach avoids a highly controversial *initial* modelling exercise to determine, once and for all, who the beneficiaries of a new investment will be. However, that does not reduce or remove the uncertainty and controversy associated with deciding who the beneficiaries are; it simply spreads it through time. In doing so, it creates uncertainty for participants because they do not know how the results of those future modelling exercises will turn out. We elaborate below.

3.3.1 Incentives Created by Sunk Costs

86. The price of avoiding the initial controversy associated with a ‘one-off’ assessment is the incentives potentially provided to users to lobby for inefficient investments or against efficient investments. This is because spreading the assessment of beneficiaries through time has the effect of turning transmission pricing into an

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EA Issues and Proposal Paper, paragraph 18.

allocation of sunk costs. Under such an approach, once a new asset is built, this will tend to change the way in which market participants pay for all of the other interconnection assets that have been built since May 2004. For example:

- Imagine the grid comprises only two interconnection assets – A and B. The beneficiaries of asset A (and the prices for using that asset) will be derived by postulating a world without it – i.e, a grid comprising only asset B. Similarly, charges for B are derived by imagining a world in which A is the only asset.
- **However, when new asset ‘C’ is built, the prices for asset A are now determined** by postulating a world in which the grid comprises not just B, but B **and** C. Likewise, charges for B are set by hypothesising a world in which A and C are the only grid elements.
- The interconnected nature of the grid and the interdependency of its elements mean that there is no reason to think that the beneficiaries of A and B will be the same before and after C is built – there might be a substantial difference (and this may also change over time).
- This means that the existing market participants may lobby for or against the **construction of asset ‘C’ for reasons that have** nothing to do with the direct costs and benefits of the bespoke investment but, rather, because they will become **‘larger’ (or ‘smaller’) beneficiaries of another part of the grid.**

87. It follows that, if the proposal is implemented, parties can be expected to view every new investment decision not simply on the basis of the direct costs and benefits of the asset in question (consistent with the above formula), but on the basis of how it will affect their estimated benefits of every other part of the grid, and so the totality of their interconnection charges. Specifically, the commercial benefits of new **interconnection asset ‘N’ to an industry participant will depend upon:**

- the impact that investment N is likely to have upon the prices it pays/receives for electricity; **less**
- the estimate of its share of the costs of investment N that will come out of the private beneficiaries test; **less**
- the change in its **allocation of the cost of investments ‘N-1’, ‘N-2’, ‘N-3’ and** everything that has come before (dating back to May 2004) or can be expected in the future.

88. The \$173.2 million in net economic benefits thought to flow from the proposal is predicated, in large part, on a belief that the first two factors above will incentivise parties to advocate only those new investments for which their private benefits exceed the costs they will face. This is said to remove the incentive for parties to lobby for projects that benefit them only because others will pay for them. However, participants will also have commercial incentives by virtue of the third factor, which involves changes in allocations of sunk costs.

89. Reallocating sunk costs cannot provide efficient incentives to parties to support or oppose new transmission investments. Yet, over time, the quantum of sunk investments subjected to the methodology will grow to include the entire **interconnected grid. Indeed, the ‘post-2004 assets’ already comprise a significant** proportion of the total grid value. It is therefore conceivable that the impact of the third factor will be larger than that of the first two. Appendix B illustrates this using an example from outside the transmission sector.
90. For these reasons, it is unlikely that the proposal will reduce the resources spent on lobbying and reviewing the methodology in the manner envisaged. Rather, it seems plausible that the nature of the transmission grid will mean that there will be even greater scope for disputes. Moreover parties may advocate against efficient investments (or for inefficient investments), not because of the private costs and benefits of the new investment in question, but because they care primarily about the allocation of sunk costs. Disputes will also arise in relation to model inputs.

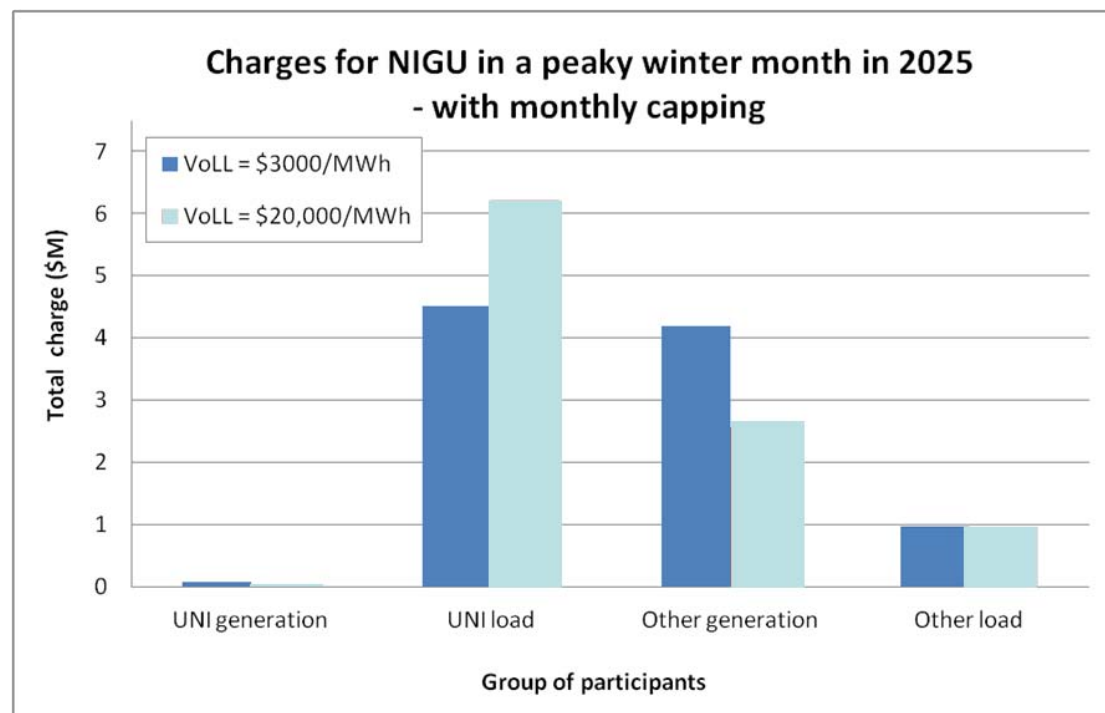
3.3.2 Potential for Disputes over Model Inputs

91. Because the interconnection charges that parties will pay will vary over time based on wholesale market outcomes, it is natural to expect that parties will agitate for the SPD model to be changed in ways that reduce their costs. Of particular relevance here are the myriad inputs to the SPD model that have a significant effect on the incidence of charges, but which require a material degree of subjective judgement. These parameters can be expected to attract particular scrutiny and controversy if the proposal is implemented.
92. For example, charges appear to be quite sensitive to the value that is assigned to unserved demand – **the ‘value of lost load’ (VoLL)**, i.e., the value that customers place on network reliability. This input can have a significant effect on the assumed incidence of private benefits once the SPD model starts postulating the removal of particular grid elements. If taking away part of the grid during a half-hour period would have resulted in some customers not receiving electricity, **their ‘private benefits’** (and the interconnection charges that they must pay) depend largely upon the costs they are assumed to avoid by the transmission asset being there.
93. It follows that, if a higher \$/MWh cost is assigned to VoLL, this will result in load in an ‘importing region’ paying higher interconnection charges.⁴⁵ Transpower has undertaken some preliminary modelling to test the sensitivity of charges to changes in VoLL. Those results are reproduced in Figure 1 below. The figure shows that increasing VoLL from \$3,000 to \$20,000/MWh may significant re-align the

⁴⁵ As VoLL increases, so too does the private benefit that consumers are assumed to derive from a particular transmission network element, since the existence of that asset may allow them to avoid those higher costs of unserved demand during peak periods.

charges. During a 'typical' peaky winter month in 2025, load based in the upper north island is estimated to assume a greater proportion of transmission costs.

Figure 1 Incidence of Charges with Different VoLL Parameters



Source: Transpower, Electricity Authority TPM Proposal (2012) – Transpower's Modelling Work SPD, EA Modelling Workshop, Auckland, 4 December 2012, p.13.

94. The problem with this sensitivity is that there is no 'unambiguously correct' value for unserved demand – there is significant scope for legitimate disagreement. Views may differ not only as to the value itself but also to the circumstances in which it may be appropriate to use a higher (or lower) estimate. For example, if the cost of additional local generation is to serve as a proxy for VoLL, it will be necessary to make an assumption about the *type* of plant that will (hypothetically) be called upon to generate, for example:
 - if the removal of a certain grid element would result in unserved demand in only a few trading periods per year, it may be appropriate to assume that, say, a new diesel peaking plant would otherwise meet that demand; but
 - if eliminating the asset would precipitate unserved demand in a significant number of periods per year, a point may come where it is more appropriate to assume that demand will be met by new base-load plant.
95. These assumptions have a significant effect on the incidence of charges, but require a considerable element of judgement. Moreover, the value of un-served demand is not the only model input that exhibits these properties – several other parameters

display similar sensitivity.⁴⁶ Parties can therefore be expected to continually agitate for these aspects of the SPD model to be changed, because they know that even a small revision in their favour may significantly reduce their charges.

96. It would certainly be possible to **'fix' these parameter values** in advance for a period, e.g. five (perhaps even ten) years. However, that is unlikely to satisfactorily address the matters described above. In our opinion, locking-in parameter values would neither eliminate the potential for disputes, nor reduce the level of controversy relative to the existing TPM, because:
 - there would inevitably be significant dispute over the initial values assigned to these parameters, and the values assigned at each subsequent review – given the potential value at stake, those disputes could conceivably culminate in costly litigation (such as judicial reviews);
 - because the SPD model would have significantly more constituent parts than the existing TPM (an inevitable consequence of using a complex quantitative model), **there would be a wider 'potential set' of parameters over which there would be controversy** when the TPM was set/revisited; and
 - **the fact that the current TPM has been 'set' for a prolonged period** has not insulated it from ongoing controversy, and so there is no reason to think that **'locking-in' VoLL, the capping period and so on would prevent parties from constantly lobbying to have those parameters changed.**
97. Moreover, even if fixing parameter inputs in advance was an effective solution (which it is not), it is simply not possible to lock-in every value. That is because occasions would arise when the SPD model could not be **'solved' with those values** – this is invariably the case with sophisticated quantitative models. Transpower will therefore need to have the flexibility to exercise its judgement when defining counterfactuals in order to produce a vector of prices. The nature and effect of these judgements may vary based on many factors, including the level of demand and other grid constraints. This is a recipe for ongoing controversy.
98. If Transpower must **make a 'judgement call'** during a trading period in order to 'solve' the model, there is a good chance that there will be **'winners and losers'** (this is frequently the case with transmission pricing). Whenever a party finds itself on **the 'wrong end' of a judgement** that could have gone either way, it can be expected to challenge that decision (provided the sum in question is not trivial). Moreover, because the SPD methodology will eventually apply to most of the grid, the frequency of disputes – and the sums at stake – will increase over time.

⁴⁶ The time period that is used to estimate benefits is one such example. This also calls for a material degree of subjective judgement and Transpower's preliminary modelling reveals that charges may vary significantly depending upon whether benefits are 'capped' on a monthly or half-hourly basis. See: Transpower, *Electricity Authority TPM Proposal (2012) – Transpower's Modelling Work SPD, EA Modelling Workshop, Auckland*, 4 December 2012, p.12.

99. Finally, it is worth recognising that such lobbying may not necessarily be limited to debates over parameter values or incremental changes. If the proposed methodological changes are made, this may signal a willingness to make widespread changes to the TPM. Industry participants may therefore be emboldened to propose entirely new pricing methodologies that (inevitably) favour their own interests. Given the substantial wealth transfers typically involved in such methodological changes, the potential upsides would be difficult to ignore – particularly as the proportion of the grid subject to the methodology expands.

3.4 Summary

100. The proposed methodology is unlikely to reduce the future costs of disputes or promote more efficient investment outcomes. In our opinion, the more probable outcome is that the proposal will significantly increase the controversy surrounding new investments and ongoing interconnection prices. Moreover, participants may be motivated by factors that cause them to act in ways that compromise dynamic efficiency, particularly, the desire to avoid being allocated sunk costs.
101. Parties can also be expected to perpetually agitate for changes to be made to the way that the methodology is implemented or, potentially, for it to be replaced with an alternative approach that favours their own interests. Parties will also have an incentive to challenge any instances in which Transpower must make an unfavourable **‘judgement call’ in order to ‘solve’ the SPD model**. The result is a recipe for ongoing controversy.

4 Potential for Inefficient Grid Use

102. In this section we explore the ways in which the proposal may reduce the efficiency of the wholesale spot market dispatch process by causing generators to adjust their bids so as to avoid the incidence of transmission charges. However, before doing so, it is instructive to reflect briefly upon the incentives that exist currently. We therefore begin by briefly describing the New Zealand wholesale market arrangements and the RCPD-based interconnection charges presently levied on off-take customers.

4.1 Status Quo

103. Currently, all generators pay connection charges and South Island generators pay HVDC charges that are more or less fixed.⁴⁷ Their expected transmission charges have little, if any bearing on their wholesale bids. Rather, the wholesale market design is directed towards promoting competition between generators that produces prices that reflect their short-run marginal costs (SRMCs). Although generators are permitted to offer their capacity at any price, the existence of competing offers normally⁴⁸ constrains the prices that they can bid. For this reason, generators:

- can generally be expected to offer to supply the market at a price that reflects their short run operating and maintenance cost (SRMC);⁴⁹ and
- will generally be **scheduled to run in line with their economic ‘merit order’**, i.e., with the lowest cost plants being dispatched first, and so on.

104. It follows that anything that **adds** to the SRMC of operating generation plant will be reflected in wholesale offers and may compromise the efficiency of the dispatch process. It was this potential for wholesale market distortions that caused Transpower to impose a peak charge to recover HVDC costs.⁵⁰ In particular, it

⁴⁷ Although, as the EA has recognised, the HAMI charge does sometimes result in certain generating units ramping down their output in order to avoid contributing to their HAMI. Recall that generators do not pay interconnection charges.

⁴⁸ For example, a base load plant that bids substantially above its operating and maintenance costs risks not being dispatched and being forced to incur the expense of shutting down and restarting its plant. **Wholesale prices should only exceed the SRMC of the ‘marginal generator’ when there is a possibility that the existing generation capacity will not be able to meet demand (and prices in the market must rise to reflect the increased SRMC of curtailing that excess demand) or when temporal or sustained market power is being exercised, e.g., when generation is being strategically withheld.** For a more comprehensive discussion, *see*: NERA Economic Consulting, *Potential Generator Market Power in the NEM, A Report for the AEMC*, 22 June 2011; and CEG, *Barriers to entry in electricity generation, a report for the AEMC*, June 2012.

⁴⁹ For hydro plants, this will include an endogenously determined opportunity cost of water.

⁵⁰ Transpower, *HVDC Sunk Cost Recovery Pricing Methodology*, 19 April 1999, p.11.

recognised that if it levied HVDC charges based upon \$/MWh dispatched (an **‘energy-based’ charge**) this would increase the opportunity cost of generating, and may result in higher wholesale prices.

105. This is because, to a South Island generator, a \$/MWh HDVC charge is the **economic equivalent of an additional variable cost, such as fuel. If a generator’s ‘true’ variable cost was \$30/MWh,**⁵¹ and an energy-based HVDC charge added, say, \$2/MWh, then it would never bid less than \$32/MWh. This is distortionary, since the HVDC charge relates to the recovery of a sunk cost, i.e., whenever the market price was between \$30 and \$32/MWh, dispatch would not be least cost. The HAMI-based parameter mitigates this inefficiency (albeit imperfectly).
106. Presently, generators do not pay interconnection charges. Rather, the costs of the interconnection assets are recovered from off-take customers (distribution companies and transmission-connected customers) based on their respective contributions to **‘regional coincident peak demand’ (RCPD) in the region in which they are located.** There are four such regions – the upper and lower North Island (UNI/LNI) and the upper and lower South Island (USI/LSI). A different approach is adopted across those regions:
 - in calculating the average RCPD in the UNI and USI regions, 12 peak demand periods are used; and
 - in calculating the average RCPD in the LNI and LSI regions, 100 peak demand periods (N=100) are used.
107. Interconnection charges for each customer are then calculated by multiplying the uniform interconnection rate⁵² **(price) by each customer’s average off-takes** at times of RCPD. Because the average RCPD is calculated over 12 peak demand periods in the UNI and USI regions this provides off-take customers with an incentive to shift load to non-peak times so as to minimise their annual interconnection charge. Indeed, if an off-take customer does not reduce its contribution to the 12 peak demand periods, and other customers do, then it will pay a larger annual interconnection charge.
108. In contrast, there is not the same incentive to reduce load in the LNI and LSI regions, because it is far more difficult to control 100 peaks. The current arrangements therefore reflect a trade-off between recovering the sunk interconnection costs, while minimising distortions to consumption in the LNI/LSI regions and providing an incentive to off-take customers in the more congestion-

⁵¹ Noting again that, for hydro plants, this will include an endogenously determined value of water.

⁵² The interconnection rate (or ‘price’) per kW used to determine off-take customers’ annual interconnection charges is the same for all customers in all locations and is calculated by dividing the required interconnection revenue by the sum of the average of the RCPDs for all customers.

prone UNI/USI regions times to reduce demand during peak times to improve the efficiency of grid usage decisions.⁵³

109. Because generators do not currently pay interconnection charges, and HVDC charges are levied on the basis of HAMI, wholesale bids can normally be expected to reflect the operating and maintenance costs of the relevant plant.⁵⁴ The profile of generation will therefore typically reflect an SRMC-based merit order, resulting in efficient, least-cost dispatch. The incentives created for efficient least-cost dispatch is a defining feature of the New Zealand wholesale market, and is a key reason that it is widely acknowledged as being at the forefront of international best practice.⁵⁵
110. If the proposal is implemented, generators will face two more variable transmission costs, which they can be expected to factor into their bids. Specifically, a generator will consider:
 - their short run operating and maintenance costs, such as fuel, labour, and so on (this might be characterised as its **'true' SRMC**);
 - the quantum of interconnection charges that it expects to pay by being deemed a **'private beneficiary' of various parts of the shared grid; and**
 - potentially,⁵⁶ the interconnection charges it expects to pay based on its contribution to the regional coincident peak injection (RCPI) in its location.
111. The second and third factors have the potential to differentially affect generators such that the 'aggregate industry SRMC' **does not reflect the 'true SRMC'**. This could reduce the efficiency of the wholesale market and the way in which the transmission grid is utilised. In particular, these charges risk compromising the efficiency of the wholesale market and unwinding some of the benefits of the existing RCPD charging arrangements. We explain their potential effects below, beginning with the incentives that might be created by the new **'beneficiaries pay' charge**.

4.2 'Beneficiaries-Pay' Charge

112. If transmission charges were to be levied upon generators in the manner envisaged by the EA, this will increase the opportunity cost of generating, and may result in higher wholesale prices. This is because, like the \$/MWh charge discussed above, **the 'private benefit' based charge is the equivalent of an additional variable cost. A**

⁵³ Like the wholesale market arrangements, the RCPD charge is also generally viewed as being a positive feature of the New Zealand arrangements, *see*: NERA Report, pp.23-24.

⁵⁴ For hydro-plants this will also include an endogenously determined value of water.

⁵⁵ For example, *see*: Hogan, W. W, 'Electricity Market Restructuring: Reforms of Reforms', *20th Annual Conference, Center for Research in Regulated Industries*, Rutgers University, 25 May 2001, pp.22-23.

⁵⁶ As we explain below, the extent to which generators will take this into account depends to a large extent upon the number of periods over which the RCPI charge is recovered.

generator can therefore be expected to take that additional expected cost into account when formulating its wholesale bids.

113. This, in itself, need not reduce the efficiency of the generation sector if all generators' costs are more or less equally (proportionally) increased.⁵⁷ In those circumstances, **the SRMC 'curve' would 'shift up' but its 'shape' would not be affected.** However, in reality, different generators will be affected differently by the proposal – such that both the level and the shape of the SRMC curve will be distorted. The net effect will be that some generators are dispatched when they have a higher 'true' SRMC than other generators not dispatched.
114. The methodology might also cause generators to modify their wholesale bids in **order to avoid being deemed 'beneficiaries'** of certain parts of the transmission grid and paying transmission charges to recover those sunk costs. A specific example contemplated in the Issues and Proposal paper is that South Island generators **might try to avoid the 'beneficiaries-pay' charge for Pole 3** of the HVDC by formulating their bids in such a way that they are seen collectively only to be using Pole 2 of the link. This scenario is postulated at paragraph 38 of the paper:⁵⁸

“If successful, the revised offering behaviour would reveal that pole 3 was not economically justified and doesn't deliver private benefits to South Island generators. The costs of pole 3 in this case should be recovered from consumers receiving private benefits from pole 3 (if any) or through the residual charge in a way that is analogous to a 'broad base low rate' tax on generators and consumers for uneconomic grid investments; and

Alternatively, if South Island generators were unable to structure their offers to avoid the beneficiaries-pay charge, this suggests pole 3 delivers private benefits to them, and that they should pay for (a portion of) the costs of pole 3, up to an amount not exceeding their private benefit.”

115. In our opinion, the situation described in the first paragraph above represents an inefficient use of grid infrastructure. The investment in Pole 3 is sunk, and so when North Island load can be served more cheaply by South Island generators, it is efficient for that infrastructure to be used to facilitate that least-cost outcome. If South Island generators act in the manner envisaged in the above passage, prices in the wholesale market will be higher than would otherwise be the case. This is unambiguously harmful to consumers.

⁵⁷ However, even in this scenario the efficiency of the final price to consumers may be compromised. This is because consumers will now see these interconnection costs in higher variable energy prices. If those costs were previously recovered through fixed charges, then this is likely to have been more efficient (given that the elasticity of demand for connection to the electricity grid is extremely low).

⁵⁸ EA Issues and Proposal Paper, paragraph 38.

116. In contrast, the perceived **‘benefit’** – identifying and charging only those parties that are **‘private beneficiaries’** – represents only a wealth transfer. Although South Island generators may benefit from avoiding the cost of Pole 3, it is simply recovered from other consumers, **leaving no ‘net’ benefit**.
117. In our view, it is not worthwhile to risk compromising the efficiency of the wholesale dispatch process in this manner in order simply to identify the private beneficiaries of a past (sunk) investment and to facilitate a series of **‘welfare neutral’** wealth transfers. It should be remembered that:
 - the investment in Pole 3 was deemed to be efficient – it is for that very reason that it was built;
 - the SRMC of using Pole 3 is very low, i.e., it is limited to the costs associated with losses and constraints; and
 - the long-run marginal cost (LRMC)⁵⁹ of the next capacity expansion is also very low, because the value of any deferral of that future capacity increment is low due to the effect of discounting.⁶⁰
118. All of these factors suggest that the TPM should **encourage** the use of Pole 3 – and of past investments more generally. However, the proposed methodology is likely to do the opposite and risks harming consumers. In our opinion, there is no sound economic basis for designing the TPM in a way that might cause generators to restructure their wholesale bids to avoid incurring sunk costs.⁶¹
119. Moreover, there is not necessarily any reason to think that generators will modify their bids in a way that causes them to collectively recover the exact amount of **additional ‘beneficiaries-pay’** transmission charges. First, if different generators have different expectations about the precise quantum of additional charges they will face, they may under- or, more problematically, **over-**estimate those costs. In fact, when faced with this uncertainty, generators might err on the high side when forecasting the cost, all other things being equal.
120. This conduct would reduce the efficiency of the wholesale dispatch process. For example, if a generator over-estimates the additional \$/MWh charges it will face

⁵⁹ LRMC reflects the cost of serving an incremental change in demand in a market, assuming all factors of production can be varied. Importantly, because LRMC is a long run concept, it accounts for the fact that firms have the option of **expanding their capacity** in order to meet an incremental increase in demand. Measuring LRMC involves estimating the costs involved with undertaking a capacity expansion **sooner than would otherwise be the case** in response to that change in demand.

⁶⁰ For example, the value today of deferring by one year a \$1b investment expected to be made in 12-months’ time is much greater than the value today of that same one year deferral applied to a \$1b investment to be made in 10 years’ time. It follows that the LRMC of the next capacity expansion increases the closer the time comes to when that increment is needed. **See:** NERA Report, p.14.

⁶¹ It is possible that the **proposal may even give rise to market power problems if it enhances generators’ ability to raise their rivals’ costs** (either of their generating units or an affiliated retailer).

through this element of the TPM, factors that extra amount into its bid and then becomes a marginal generating unit, then:

- wholesale spot prices will be higher throughout the country (or within a particular region, if transmission constraints apply); and
- those prices will exceed the underlying SRMC of generating, i.e., operating and maintenance costs plus transmission charges.

121. Even where a generator underestimates its costs and bids lower than its actual costs this will tend to result in an economically inefficient dispatch (with that generator being dispatched when it was not truly the lowest cost).
122. Second, **'marginalising' what was previously either a fixed cost (HVDC), or a cost recovered from off-take customers (interconnection charges)** will reduce the certainty of cash-flows for generators (and retailers). This additional risk, in effect, represents an additional 'cost of doing business' that generators will expect to recover through their prices. Specifically, if the proposal is implemented, one might expect to see generators (and, in turn, retailers) incorporating additional risk premiums in their prices over time. We describe this amplification of risk and its attendant effects in more detail in section 5.
123. These factors would result in short- to medium-term static inefficiencies and inappropriate investment signals that may compromise dynamic efficiencies over the longer-term. These distortions above may be exacerbated by the proposal to levy **50% of the 'residual' charge on generators** based on their contribution to RCPI. This new charge has the potential to further compromise the efficiency of grid usage.

4.3 RCPI Charge

124. For the 2012/13 pricing year, the RCPD interconnection rate is \$90.66/kW, or around \$90,000/MW. In other words, over 100 half-hour peaks (in the LNI and LSI), every MW of peak demand attracts around \$900 in transmission costs, or \$1,800/MWh (\$900 x 2). Similarly, over 12 half-hour peaks (in the UNI and USI), every MW of demand attracts around \$7,500 in transmission costs, or \$15,000/MWh. Although off-take customers might try to switch or reduce load to avoid those peaks,⁶² there is no direct effect on **generators'** wholesale bids.
125. Under an RCPI arrangement, whenever a generator perceives there is a significant probability that a given trading period will be a chargeable peak it can be expected to factor this information into its offer price in the wholesale market. By doing so, it runs the risk of not being dispatched, which entails costs. However, depending upon how the charge is designed, the profits foregone from not generating during the

⁶² As we mentioned earlier, this is more feasibly achieved in the UNI and USI regions, because it is far more difficult to control 100 peaks.

period may be lower than the additional transmission costs it would face if a peak occurred and it had not factored the additional RCPI charge into its bid.

126. Currently, the \$90.66/kW interconnection rate⁶³ is used to recover 68% of total transmission costs through the RCPD charge.⁶⁴ The percentage that will need to be recovered via the RCPI charge will be lower, since it only needs to collect half of whatever interconnection costs remain **after the ‘beneficiaries-pay’ charge is applied**. The EA estimates that the RCPD and RCPI charges will recover between 5% and 50% of total transmission costs and so,⁶⁵ based on that analysis, the RCPI charge may need to recover between 4% and 37% of interconnection revenue.⁶⁶
127. **Suppose that the RCPI charge in the region of interest is levied based on generators’ contribution to 100 peaks (i.e., N=100).** We noted above that, currently, every MW of peak demand attracts \$1,800/MWh in transmission costs. If the RCPI charge must deliver, say, 20.5% (the mid-point between 4% and 37%) of the existing interconnection revenue, every MW of additional peak injection would attract the equivalent of around \$370/MWh in transmission costs (\$1,800MWh x 0.205). Unlike the RCPD charge, this can be expected to affect spot market outcomes.
128. Specifically, when formulating their bids, generators will assess the probability that a period will be one of the 100 peaks. They will include in their estimate of SRMC (and presumably their bid prices) the probable cost to them of this charge. This will result in elevated prices in the wholesale market during periods of high demand. This is not necessarily an inefficient outcome in and of itself.
129. Higher peak prices can be appropriate if they reflect an estimate of the cost of using the grid in the peak period (in terms of heightened probable VoLL and/or heightened need for new capacity investment). It is not obvious that the RCPI approach will do this. For example, it is not necessarily the case that every one of those 100 peaks (or even any) will see demand approaching maximum capacity. In fact, there may be plenty of spare capacity, despite it being a peak. In those circumstances, the actual costs imposed by **‘peak’ injectors may be no different to the costs imposed by ‘non-peak’ injectors, yet the RCPI charge is levied nonetheless.**
130. The RCPI will also increase uncertainty. To illustrate, imagine that **the ‘true SRMC’** component of an offer price would otherwise be \$300/MWh. As we noted above,

⁶³ See: Transpower, *Year Specific Data for 1 April 2012*, available at: <https://www.transpower.co.nz>.

⁶⁴ In 2012/13, interconnection revenue is \$547m, and accounted for 68% of the \$805m total transmission revenue for the pricing year.

⁶⁵ EA Issues and Proposal Paper, Figure 6, p.73.

⁶⁶ The EA estimates that the residual charge will recover from 5% to 50% of total interconnection revenue. **In other words, based on the 2012/13 numbers, the total ‘residual’ revenue will be between \$40.25m (5%) and \$402.50m (50%).** The RCPI charge will need to contribute half that sum and so will be between \$20.13m (\$40.25m x 0.5) and \$201.25m (\$402.50m x 0.5). It follows that the RCPI charge will be between 4% (\$20.13m ÷ \$547m) and 37% (\$201.25m ÷ \$547m).

the application of the RCPI may add up to \$370/MWh to the wholesale price during periods in which a peak was considered possible (or approaching double that **implied by the EA's range of estimates**). Note that this increase would be in addition to any uplift **already resulting from the application of the 'private-benefit' charge** described above. Moreover, remember that **this 'risk-premium' would be factored into generators' offer prices** whenever there was a significant probability of a peak – not just the 100 periods of actual peaks.

131. It follows that, if the RCPI charge is applied to, say, 100 peak periods, then generators can be expected to factor the above risk premiums into their bids in a number of periods that is some multiple of that say, 200 or 300, with some probability. There is again not necessarily any reason to be confident that generators will modify their bids in a way that causes them to collectively recover **the exact amount of additional 'RCPI' transmission charges**. The logic is the same as **for the 'beneficiaries pay' charge described above, namely:**
 - if different generators have different expectations about the precise quantum of additional costs they will face through the RCPI charge, they may under- or, more problematically, *over*-estimate those costs when formulated bids; and
 - more generally, the introduction of an RCPI charge would reduce the certainty **of generators' (and retailers') cash-flows and thus the 'cost of doing business'** – they may therefore incorporate additional risk premiums in their prices.
132. Short of eliminating the RCPI charge entirely, the most effective way to reduce these incentives is to recover the charge over a greater number of peaks. The extreme approach would be to recover it over all of the 17,520 half-hour periods in a year. Doing so would swing the 'bid arithmetic' in such a way that the foregone profit in a period from not being dispatched would exceed the additional transmission costs incurred. However, at that point the charge essentially resembles a broad-based tax, which begs the question: why levy that tax on generators?
133. **Levying a 'tax' on generators** would appear not to offer any meaningful prospect of eliciting desirable behavioural change, since it does not produce a **'price signal'**, as such. Instead, at that point, the principal purpose of the RCPI charge would be to collect the residual sum of unrecovered revenue in the least distortionary way. In our opinion, that objective would be likely to be best achieved by continuing to recover the sum from the broader base of off-take customers. Moreover, levying an RCPI charge risks reducing the effectiveness of the RCPD charge.
134. As we mentioned above, we understand that the RCPD element of the current interconnection charging regime is generally thought to be working well. The proposed change would dilute the strength of the signals currently being sent to off-take customers in regions prone to constraints. This is because the RCPD charge will only need to recover between 4% and 37% of the revenue that it currently delivers (based on EA estimates). This effect could be mitigated by reducing the

number of peaks (i.e., by **‘recalibrating’ the signal**) but, as we explained above, there would be no incremental benefit associated with the new RCPI element.

135. It may therefore be feasible to introduce an RCPI charge without making things ***too much worse***. This is likely to involve spreading the RCPI charge over a large number of peaks and reducing the number of peaks for the RCPD charge. However, the relevant threshold for change is whether the charge will promote the efficient use of and investment in infrastructure. In our opinion, it would not. Irrespective of its design, an RCPI charge would seem not to offer any clear benefits and, if it was not implemented carefully, it could give rise to a number of distortions.

4.4 Summary

136. Currently, the New Zealand wholesale market design means that, most of the time, generation plant should be **‘dispatched’ in an efficient ‘least cost’ basis**, according to its economic merit order, as given by the ascending SRMC (as bid) of running each type of plant. The RCPD-based interconnection charge is also generally viewed as being a positive feature of the New Zealand arrangements. The proposed methodology risks compromising both of these beneficial aspects of the New Zealand market, without offering any obvious off-setting benefits.
137. The **‘beneficiaries pay’ charge** risks causing generators to adjust their bids so as to avoid bearing a greater share of the sunk costs of past investments. This would distort the dispatch process and give rise to higher wholesale prices, in order to facilitate wealth transfers that offer no efficiency benefits. The charge will also make **generators’ cash**-flows less certain, which may result in additional risk premiums being incorporate in wholesale (and, in turn, retail) prices over time.
138. The RCPI charge may create further distortions if it is not designed carefully. In particular, it may inflate further the additional risk premiums (described above) that generators may require to off-set reduced certainty of cash-flows. It may also weaken the beneficial incentives provided by the existing RCPD charge. Although it may be possible to design the charge so as to mitigate these distortions, it would still not offer any clear benefits, which obviates the rationale for such a change.

5 Risk Amplification

139. The EA is currently exploring mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid. It is also examining ways of facilitating, or providing for, an active market trading financial hedge contracts for electricity.⁶⁷ These two priority projects are explicitly directed at mitigating volatility and managing risk. These projects may be undermined if the proposal is implemented, since it has the potential to amplify risk throughout the entire supply chain, with myriad attendant consequences.

5.1 Effect on Generators

140. The proposed methodology contemplates generators paying interconnection charges. This **would ‘marginalise’** a cost that previously was either fixed (the HVDC charge) or recovered from off-take customers (interconnection charges). Generators can be expected to take those additional variable costs into account when formulating their wholesale bids. In sections 4.2 and 4.3 we explained that this may precipitate a number of outcomes:

- **The ‘beneficiaries pay’ charge may cause generators to adjust their bids so as to** avoid bearing a greater share of the sunk costs of past investments. The consequence is that prices in the wholesale market will be higher in some parts of the country than if generators had not modified their conduct.
- **Generators’ cash-flows** will also be less certain, which may result in additional risk premiums being incorporate in wholesale (and, in turn, retail) prices. The consequence is that prices in the wholesale market may be higher everywhere, regardless of whether generators engage in the above conduct.
- The RCPI charge may create further distortions if it is not designed carefully. In particular, it may inflate further the additional risk premiums (described above) that generators may require to off-set reduced certainty of cash-flows. It may also weaken the beneficial incentives provided by the existing RCPD charge.
- Different generators may also have different expectations about the precise quantum of additional transmission costs they will face through the **‘beneficiaries pay’ and RCPI charges. They may therefore under-** or, more problematically, **over-**estimate those costs when formulated bids.

141. In one way or another, these outcomes are all products of the additional volatility and uncertainty likely to be associated with the proposal. Put simply, it is conceivable that wholesale prices will be higher and significantly more volatile

⁶⁷

See: <http://www.ea.govt.nz/our-work/programmes/priority-projects/>.

under the proposal than under the current TPM. This will, of course, have implications for retailers who will ultimately be forced to pay those prices.

5.2 Effect on Retailers

142. **Electricity retailing is essentially a ‘risk management’ function that** intermediates between the large scale transactions and risks arising in the spot market and the rather different needs of individual end users, who will generally have a lower appetite for risk.⁶⁸ Customers pay retailers for this risk management service (which is bundled with metering, billing services, and so on) and, in return, they are offered a price for delivered energy that is typically fixed for a year.
143. Before it can set its prices, a retailer must estimate the costs that it is likely to face throughout the period for which those tariffs will apply – usually a year. Anything that serves to increase the volatility of **retailers’ input costs** over that timeframe may cause those businesses to include additional premiums in their tariffs to reflect that heightened risk. In our opinion, the proposal is likely to have that effect on prices in the retail market, because:
 - retailers are likely to face more volatile wholesale energy costs, for the reasons we set out in the previous section; and
 - further volatility will be introduced by the new SPD-based interconnection charge that retailers will be required to pay.
144. It is likely to be a challenging exercise for a retailer to predict the quantum of SPD-based charges that it will be required to pay over the course of a year. The pattern of **‘private benefits’ will depend on load-flow patterns** (which may be affected by the conduct of generators, described above), and where and when new generation/load connects and disconnects. Changes in any of these factors could have a significant **impact upon a retailer’s input costs, and its profitability.**
145. There appears to be no way of hedging against those risks through financial instruments, since no counter-parties would exist that would be prepared to take **the ‘other side of the bet’**. The only way to deal with that increased cost of risk is through retail prices. Retailers will therefore face a choice:
 - **on the one hand, if they price ‘aggressively’, they may win more customers, but** will face significant financial repercussions if their transmission costs turn out to be higher than expected; and

⁶⁸ Although the volume of electricity that will be consumed by customers can be forecast, it cannot be known for certain. The same can be said for pool prices. To mitigate the risks they face from uncertain volumes and prices, retailers may enter into financial hedging contracts with generators or third parties. **Larger retailers are also insulated to a material extent by the ‘natural hedges’ provided by their own generation portfolios.**

- **on the other hand, if they price ‘conservatively’, they will protect themselves** against higher than expected transmission costs, but they may lose customers if other retailers adopt a riskier strategy and adopt lower prices.

146. On balance, in our view the second scenario is more likely. Specifically, the reduced certainty of cash-flows and increased input price volatility is likely to result in retailers incorporating additional risk premiums in their tariffs. Larger retailers may have an advantage over smaller retailers in this respect, since they will generally have a greater stock of institutional capital upon which to draw. They may therefore be better placed to predict the likely quantum of SPD charges and to arrive at an appropriate risk premium.⁶⁹
147. Larger retailers may also be better placed to manage the increased volatility in wholesale energy costs described in the previous section. That is because they are more likely to **be on ‘both sides’ of a transaction**, i.e., by owning both generation and retailing assets.⁷⁰ **Although a business’s retail arm may face a higher/more volatile** wholesale price, its generation arm may be receiving that same high price (although not necessarily⁷¹). **Because smaller retailers do not have these ‘natural hedges’, the** amplified wholesale risk may be felt more acutely, i.e., it may:
- make them especially vulnerable to any wholesale price shocks brought about by the types of bidding conduct described above (and in more detail in sections 4.2 and 4.3), with the associated financial detriments; and
 - potentially increase their net spot market exposure and, in turn, the prudential security that they are required to provide under Part 14 of the *Electricity Industry Participation Code 2010*.⁷²
148. The increased price volatility may therefore make it more difficult for smaller businesses to enter the retail market and to expand once there. This is potentially problematic because, although small retailers currently comprise only a modest share of the market,⁷³ they appear to have a significant disruptive influence on

⁶⁹ Larger businesses may also be best placed to undertake load control during predicted periods of peak demand (e.g., switching off interruptible load) so as to reduce the quantum of transmission charges that they are assigned during those times.

⁷⁰ **These providers are sometimes called ‘gentailers’.**

⁷¹ If there is nodal price separation and a generating unit is distant from the retail load, then the business **will not necessarily be on ‘both sides of the bet’** – its generating arm may not receive the high price being paid by its retail arm.

⁷² Prudential security may take the form of a cash deposit, a bank guarantee, a third party guarantee from a party with an acceptable credit rating, a bond from a surety with an acceptable credit rating, and/or a hedge contract lodged with and settled by the clearing manager. Parties with an acceptable credit rating (A- Standard & Poors or equivalent) do not need to provide prudential security.

⁷³ Currently, the largest electricity retailers and their subsidiaries (Contact/Empower, Genesis/Energy Online, Mercury/Bosco Connect, Meridian/Powershop and Trustpower) account for around 95% of the New Zealand market. (These shares are based on the percentage of energised installation control points

prices and service offerings. In other words, the heightened risk precipitated by the proposal will not only increase retail prices, it may also serve to reduce competition at the retail level.

5.3 Summary

149. There is a strong likelihood that the proposal would significantly increase price volatility and amplify risk throughout the supply chain. This may cause generators and retailers to incorporate additional risk premiums in their prices. The retailers that are likely to be least well-placed to manage these additional risks are smaller **retailers that do not have ‘natural hedges’**.

(ICPs) held by each retailer as at November 2012. **See:** <http://www.ea.govt.nz/dmsdocument/14146>). The remainder of the market is made up of a number of small, independent retailers such as Tiny Mighty, Just Energy and King Country Energy (**See:** <http://www.switchme.co.nz/residential/power-companies.php>).

Appendix A Some History

150. In this appendix we recount some history. We do so because most, if not all of the material presented in the EA paper has been considered many times before. Within the last two and a half years, three separate bodies have conducted wide-ranging reviews of the TPM – including the CEO Forum, the TPAG and the **EA’s predecessor** (the Electricity Commission). However, after careful (and lengthy) consideration, these groups recommended only incremental revisions to the TPM.
151. The EA appears to have reached a different conclusion based largely on its belief **that the wider application of ‘market-based approaches’ and the ‘beneficiaries-pay’** principle will lead to better outcomes. That being the case, it is worth beginning our retrospective in the early 2000s. At that time, it was thought that applying these very principles would give rise to efficient, market-driven transmission pricing and investment. However, that is not what transpired.

A.1 Market-based Transmission Investment

152. The initial thinking in New Zealand (and elsewhere) was that the existence of full nodal pricing would give rise to the possibility of market-driven transmission pricing and investment being undertaken by parties that would benefit from those investments, i.e. the beneficiaries. In principle, users (or groups of users) have an incentive to invest in new transmission capacity if the cost (to them) of augmentation is expected to be less than the continuing costs (to them) of the losses and constraints that will otherwise be incurred.⁷⁴
153. The expectation was that investment by beneficiaries would reduce (or eliminate), the need to undertake centrally planned transmission investment, and to reduce (or eliminate) the need to fund such investment through regulated transmission prices. To this end, in 2002 the industry and the government canvassed the possibility of introducing financial transmission rights (FTRs) in order to create property rights that would improve the potential for market-led transmission investment.⁷⁵
154. Of course, FTRs were not introduced at that time and, to date, there have been no user-driven transmission investments in HVAC or HVDC assets. In hindsight, that

⁷⁴ Such investors need not receive a regulated revenue stream. Rather, the motivation for investment is to avoid the costs of future losses and congestion. However, to ensure that investors do not lose the benefits of their investment, they must receive a **right to any network ‘congestion rents’, ie, revenue that arises from a divergence in the spot price between locations, should the link in which they have invested become congested in the future. Such rights might be ‘physical rights’ to the dedicated infrastructure, or rights that are purely financial in nature – FTRs.**

⁷⁵ Such rights were intended also to allow market participants to hedge locational price risk resulting from transmission congestion. See: E Grant Read, *Financial Transmission Rights for New Zealand: Issues and Alternatives*, prepared for the New Zealand Ministry of Economic Development, 8 May 2002.

outcome is unsurprising, when one considers the formidable obstacles presented by the economic characteristics of transmission networks. These factors dramatically reduce the attractiveness of market-based investments, and do not obviate the need for some degree of centralised transmission planning and regulated pricing. These challenges include:⁷⁶

- the economies of scale associated with new transmission investments, which mean that, once built, transmission lines eliminate congestion, rendering any physical or FTRs worthless;
- **the strong incentive that parties have to ‘free ride’, e.g., if a generator stands to benefit from congestion being eliminated, it may be better off waiting and hoping that someone else invests first (creating a potential stalemate); and**
- the fact that there is often more than private benefits at stake, e.g., increased transmission can reduce market power and increase network reliability, and there are also valid economic and **national security reasons to ‘err on the side of caution’ and overbuild (and earlier)** than underbuild (or build late), given the substantial asymmetric risk.

155. To be sure, market-based and beneficiaries-pay approaches have their place – even in a transmission pricing framework.⁷⁷ However, the characteristics of transmission and the practical challenges described above mean that there are limits to their usefulness, and seeking to apply those principles too widely can lead to inefficiency. So it proved in New Zealand. It is widely accepted that the experiment with market-based transmission investments and pricing during this period failed to deliver dynamically efficient outcomes and resulted in underinvestment.

156. By early 2000, broader concerns about the performance of the electricity sector resulted in a Ministerial Inquiry to examine whether the regulatory arrangements for the transmission, distribution, wholesale and retail sectors were best suited to ensuring that electricity was delivered in an efficient, reliable and environmentally sustainable manner to all consumers.⁷⁸ The government indicated that, if necessary, it would introduce legislation which would enable it to regulate.

⁷⁶ In principle, from an economic perspective, the conditions for optimal expansion of the transmission network are that: 1) additional generation capacity should be built only if the total savings in the cost of generation (and demand management) exceed the additional transmission cost; and 2) additional capacity should be sized such that the marginal cost of generation savings and loss reductions (indicated by the difference in future spot prices – or generation costs – at different locations) equals the marginal cost of building additional capacity. In other words, in principle, investment will be efficient up to the point where the cost of one more unit of transmission capacity – the long-run marginal cost (LRMC) – is equal to the avoided cost of future constraints and losses – the short-run marginal cost (SRMC). However, the challenges listed above mean that it is neither feasible nor even advisable to seek to implement this decision rule in practice.

⁷⁷ Connection assets are an example.

⁷⁸ **See:** <http://www.ea.govt.nz/about-us/structure/background-to-governance-and-regulation/>.

157. In response, industry participants began developing a set of self-governance arrangements. In April 2003, the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) put forward an integrated proposal for the sector. We understand that part of the suggested arrangements was a proposal that new transmission investments be required to have support from 75% of the perceived beneficiaries.⁷⁹ This mechanism was intended to preserve some of the elements of a market-based approach for new transmission upgrades.⁸⁰
158. However, later that year the arrangements put forward by the EGEC did not attract sufficient support from the industry, which led the government of the day to establish the Electricity Commission ('EC' – the **EA's predecessor**) under the *Electricity Act 1992*, with a view to regulating the market. Upon the inception of the EC in 2003, the *Electricity Governance Rules* (EGRs – developed by the Ministry of Economic Development) were introduced, including a regulatory TPM.⁸¹ The arrangements resembled closely those that had been proposed by the EGEC, but with at least one notable exception.
159. Namely, the 'market-based arrangements' for undertaking new transmission investments that had been proposed by the EGEC (and rejected by the majority of the industry) were excluded and replaced by an administrative process. Those administrative mechanisms remain a feature of the TPM today – the current incarnation of which took effect on 1 April 2008. The EA stated in its decision-making and economic framework paper that it is 'unclear' why this administrative approach was favoured, but offers two possible explanations:⁸²
- concern that the market-based approach would have resulted in under-investment due to problems with free-riders (the EA claims that the proposal contained procedures designed to overcome these problems); and
 - a view that the associated decision-making process would be too time-consuming and costly (the EA states that these costs must be weighed against the time spent debating transmission investments under the TPM).
160. A potential additional explanation is that the architects of the EGRs were cognisant of the myriad challenges associated with giving effect to a beneficiaries-pay

⁷⁹ See: EA Consultation Paper, paragraphs 4.3.13 to 4.3.17.

⁸⁰ The idea was that, over time, as more and more grid assets were upgraded, long-term contracts would have replaced the TPM as the means by which Transpower's revenue was generated.

⁸¹ Note that there has been a transmission pricing methodology in existence in New Zealand since the 1980s, but it was not incorporated in regulations until 2003, whereupon it was included in the *Electricity Governance Rules* (it has since been incorporated into the industry Code). Note that Contact Energy Ltd (Contact) and Meridian Energy Ltd (Meridian) sought a judicial review of the process followed when the initial TPM guidelines were developed. This action was successful and the guidelines were set aside on 29 August 2005. See: *Contact Energy Limited and Meridian Energy Limited v Electricity Commission* (CIV 2005 485-624, 29 August 2005, McKenzie J).

⁸² EA Consultation Paper, paragraph 4.3.16.

principle in a transmission context, which we set out in sections 3.2 and 3.3. If so, the TPM – and this element in particular – might reasonably be characterised as a conscious policy response to an approach that was influenced too heavily by the desire to apply market-based approaches and beneficiaries-pay principles.

161. To be clear, we are postulating this alternative explanation with the benefit of hindsight. We do not know exactly why the administrative mechanism was favoured over the TWG proposal. Nonetheless, the exclusion of this particular element of the EGE framework is conspicuous and indicates that there was widespread dissatisfaction with it at the time. Tellingly, the principles that underpinned that methodology have many parallels to those that have been applied in one form or another to arrive at the approach set out in the Issues and Proposal paper.

A.2 Reviews of the TPM

162. The TPM defines how Transpower will recover the cost of its existing assets,⁸³ and is supplemented by administrative processes for approving new investments.⁸⁴ Since its inception, it has been the subject of significant ongoing controversy. This is more or less inevitable given that small changes in the methodology can lead to large changes in the incidence of charges. In just the last three years, the TPM has been the subject of three separate reviews – by the industry CEO Forum, the EC and the TPAG (a body that was formed as part of the EC review).
163. Each group undertook a thorough examination of the existing arrangements. The CEO Forum gave particular attention to whether the TPM could be modified so as to provide enhanced locational signals to grid users – especially generators (who do not currently pay interconnection charges).⁸⁵ The idea was to test whether a price signal could be introduced that would reduce the amount that Transpower would need to spend building and maintaining the grid, without imposing even higher costs elsewhere, e.g., higher fuel costs.⁸⁶

⁸³ It is therefore arguably more akin to a **cost** allocation methodology than a pricing methodology.

⁸⁴ These new investment approval prices used to be administered by the EA (then the Electricity Commission) under the auspices of the Grid Investment Test (GIT) framework. Those capital investment approval processes have since been transferred to the Commerce Commission under the new regulatory arrangements set out in Part 4 of the *Commerce Act 1986*.

⁸⁵ Generators are much more likely to respond to price signals than major load because it is a more important cost driver. Typically, the cost of transmission is a secondary consideration for major load when deciding upon a location. Other factors such as the cost of real estate, labour and the location of a key input into production (forests for a pulp and paper mill; and deep water port for an aluminium smelter, etc) will typically be more important.

⁸⁶ The most obvious additional cost would be the higher fuel costs that generators might be forced to pay by locating closer to load. If the increase in fuel costs is greater than the reduction in transmission spend, then society as a whole is worse off as a result.

164. The potential ‘signal delivery mechanisms’ that were considered included a ‘tilted-postage stamp’ methodology, and the ‘capacity-rights’ and ‘arbitrageur’ market models for the HVDC link. The touchstone for the assessment of each of those options was their potential to enhance economic efficiency by altering the commercial incentives facing market participants and ultimately their conduct, so as to produce more desirable outcomes. Change for the sake of change was not an objective. In particular, it was recognised that:⁸⁷

“[O]ptions that simply alter the incidence of transmission changes (which is inevitable) to the financial advantage of one party or another, but do not give rise to any material improvement, will simply impose needless additional regulatory costs. Ultimately, reform will only deliver economic benefits if desirable behavioural change is brought about. A reform option must lead to real changes in the commercial behaviour/decisions of the relevant parties, in the manner intended.”

165. This criterion is critical – not just because it represents an uncontroversial threshold for change, but also because it was the lack of potential for desirable behavioural change that caused TPAG to recommend against the introduction of enhanced locational signals.⁸⁸ The modelling that was undertaken as part of that process (much of it by Transpower) revealed that there was little point in seeking to provide a locational signal, because:

- generation and load was likely to be built in largely the same locations, since location decisions were driven more by other factors (e.g., fuel availability) than by transmission prices; and
- Transpower had recently committed to several large investments (a 400kV capable link in the upper North Island, and Pole 3 of the HVDC), and so those costs could no longer be avoided, reducing the potential benefits of modifying the price signal.

166. The TPAG consequently concluded that there would not be sufficient cost savings from deferring transmission investments by introducing an enhanced locational signal (**in large part because many of Transpower’s ‘big’ investments had already been decided upon**). It therefore refocused its efforts on ensuring that the TPM did not create perverse incentives to use the existing sunk assets inefficiently. The three aspects of the TPM that it considered included:

- various arrangements for static reactive compensation, with the group favouring an amended kvar charge option;

⁸⁷ NERA Economic Consulting, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.1 (hereafter: ‘NERA Report’).

⁸⁸ See: Transmission Pricing Advisory Group, *Transmission pricing analysis, Report to the Electricity Authority*, 31 August 2011 (hereafter: ‘TPAG Final Paper’) and Transmission Pricing Advisory Group, *Transmission pricing discussion paper*, 7 June 2011 (hereafter: ‘TPAG Discussion Paper’).

- whether shallower or deeper connection charges should be employed, with the group concluding that there was not a clearly attainable efficiency gain to warrant a change from the status quo; and
- the allocation of HVDC costs – a matter that divided the group, with some members favouring a transition to a postage stamp charge and others considering that the potential efficiency gains were not sufficiently material to warrant such a change.

167. In broad terms, the CEO Forum and the TPAG that followed it concluded that the current TPM was, for the most part, sound – and not demonstrably inferior to alternatives. Those bodies also recognised that material changes would entail substantial wealth transfers and risk giving rise to unintended consequences. That prudence is as advisable now as it was then. Many of these potential downsides arguably do not receive sufficient attention in the Issues and Proposal paper, as we have explained in the body of this report.

A.3 Summary

168. We have navigated this period of history because it is worth remembering that, in the early 2000s, it was thought that applying many the principles that underpin the proposed methodology would give rise to efficient, market-driven transmission pricing and investment. It did not. Instead, that experiment failed because insufficient attention had been given to the impracticability of applying **market-based principles and the ‘beneficiaries pay’ philosophy to certain types of** transmission infrastructure, given its economic characteristics.
169. The result was market failure, which manifested primarily in underinvestment and led, ultimately, to the introduction of the TPM and the associated administrative processes for approving new investments. Since its inception, the TPM has, understandably, proved controversial – particularly the charging arrangements for the HVDC link. However, although several recent reviews have identified some areas for incremental improvement, there was no call for fundamental changes, or for the wider **application of ‘beneficiaries pay in proportion to benefit’ principles.**

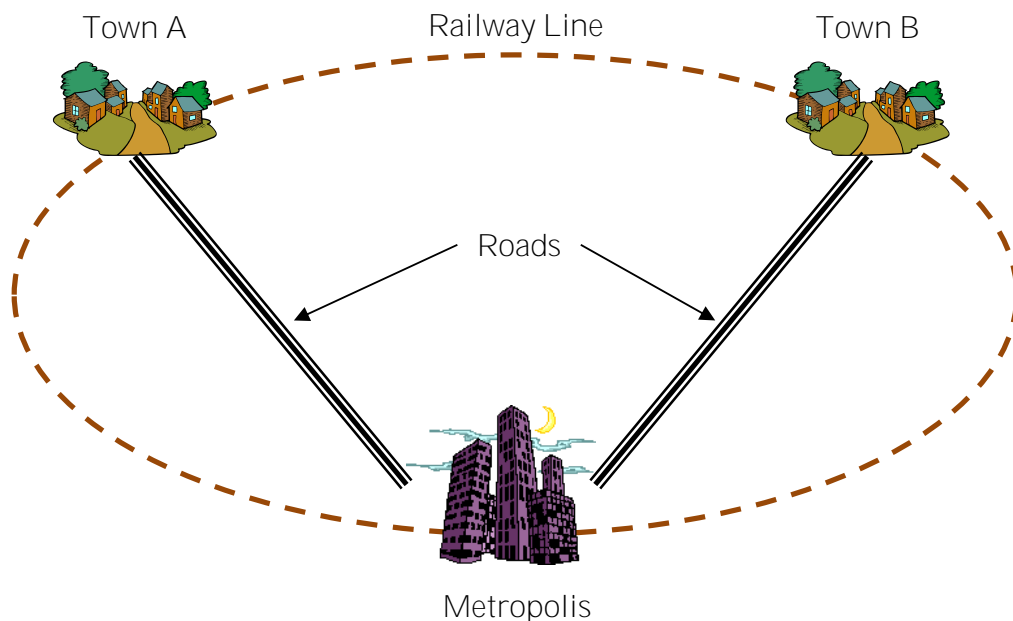
Appendix B Worked Example

170. In this appendix we provide a worked example from outside the transmission sector that illustrate the potential shortcomings associated with setting prices for a service based on the changing profile of beneficiaries. The example highlights the potential for such an approach to lead to ongoing disputes and, ultimately, inefficient investment outcomes.

B.1 Road versus Rail

171. Imagine two country towns that have congestion problems on the existing highways connecting them to a local metropolis. Suppose further that the respective local councils have responsibility for the provision of the highways and the congestion problems could be solved by upgrading them. However, imagine that the congestion could also be alleviated by investing in a new shared railway serving both towns. Figure 2 illustrates.

Figure 2 Investment in Road versus Rail



172. Suppose finally, for the sake of simplicity, that the costs and benefits offered to each town by the two options (upgrading the highways or building the train line) are identical (other things being equal). The following matrix describes the benefits and costs of each investment.

Table 1 Matrix of Benefits

Option	Economic (social) Benefit per Town	Overall (social) Net Economic Benefit
Train Only	B_T	Positive & the highest
Highway Upgrade Only	B_H	Positive & 2 nd highest
Train given Highway Upgrade	$B_{T/H} < B_T$	Negative
Highway Upgrade given Train	$B_{H/T} < B_H$	Negative

173. Table 1 illustrates that that overall benefits are maximised if the ‘train only’ investment is made. It also illustrates that, if the train line is built, there is no benefit associated with upgrading the highway – in fact, the outcome is negative. In other words, the most efficient outcome is that in which the railway investment proceeds and the highway upgrade does not.
174. Imagine that a central planner is cognisant of the above values and determines that the railway line should be built. Imagine also that she simultaneously commits to charge the citizens of each town a price for using the railway line that reflects their **proportion of ‘private benefits’** – a sum that will change over time as circumstances evolve in each location (in the same way that the EA proposes to change interconnection charges over time). We explore the implications below.

B.2 Implications

175. If neither town upgraded their highway, then the railway costs will be shared equally, because each benefits **by the same amount “ B_T ”**, i.e., their shares will be 50% ($B_T \div (2 \times B_T)$) of the cost of the railway line. However, if one town decides subsequently to upgrade its highway, then the benefit that it derives from the railway will fall to $B_{T/H}$ – reflecting the lower valuation its citizens would then place on train travel, given the improvement to the road. The **town’s share of** benefits from the railway line will consequently decline and its citizens will have to pay a smaller proportion of the total costs, i.e., $B_{T/H} \div (B_{T/H} + B_T) < 50\%$.
176. **Each town’s decision about whether to upgrade its highway therefore ceases** to be about the costs and benefits associated with that bespoke investment. The additional factor that is now relevant to that investment calculus is the expected change in the costs they will be required to pay for the railway line – a sunk cost. In effect, each town now receives an artificial subsidy for upgrading its highway in the form of a lower allocation of the costs of the railway. Mathematically, the subsidy can be expressed as follows:

$$\text{Artificial subsidy for highway} = \text{total railway line costs} \times (50\% - B_{T/H} \div (B_{T/H} + B_T))$$

177. **This artificial subsidy may be sufficient to ‘tip’ the ‘private’ value of the highway upgrade** (given the existence of the railway line) from negative to positive – causing an inefficient investment to be undertaken. Alternatively, if the town did not have responsibility for the highway upgrade, it would have a strong incentive to lobby the central planner to undertake this inefficient investment. It would do so not because of the benefits of the highway per se, but because of the costs that it would then avoid by contributing less to the past investment in the railway.
178. By way of example, imagine that the total cost of the railway train per annum was \$100m and that the cost of a highway upgrade was \$20m. Suppose also that the benefits of a highway upgrade given that the railway line already exists are equal to \$15m. In these circumstances, it is inefficient for the highway upgrade to proceed, because it has negative net benefits:

Net benefits of highway given the existence of the railway line = \$15m - \$20m = -\$5m

179. **However, imagine that upgrading the highway reduced the ‘private benefit’ to the town from having the railway line by 20%** (because its citizens use it less, following the improvement in the highway). In this case, **that town’s share of the railway’s** costs will fall from 50% to 44% $((1 - 0.2) \div (1 + 1 - 0.2))$. This will reduce its share of the payments for the \$100 pa railway costs from \$50m pa to \$44m pa – a saving of \$6m pa. This will, in turn, make the investment in the highway privately profitable – but only because its allocation of the past investment cost is reduced.

B.3 Summary

180. The above is a stylised example of the type of effects that one might expect to observe if the proposal is implemented. However, they may be even more pronounced due to the interconnected nature of the grid and the fact that all investments are undertaken by Transpower. In the above example, each town had to pay for their own highway upgrade and the benefits of this were localised to that particular town. In a transmission context, one might expect to see parties lobbying for a new investment for which they were not beneficiaries at all, simply because the interconnected nature of the grid means that they will be deemed greater or lesser beneficiaries of other assets.