Appendix F Cost benefit analysis of TPM proposal

Summary

1.1 This Appendix provides an economic cost-benefit analysis (CBA) of the Authority's proposal for determining the transmission pricing methodology (TPM), as set out in the body of this issues paper, Transmission Pricing Methodology: issues and proposal.

1.2 Although the primary focus is on the Authority's proposal this Appendix compares the results for the Authority's proposal against the approach supported by the majority of the Transmission Pricing Advisory Group (TPAG). The minority TPAG view supported the current TPM but with explicit (kVAR) charges for network reactive support services. Although chapter 6 of this paper discusses a wide range of alternative options for the TPM, the Authority has decided to include an assessment against the TPAG majority view to ensure an even-handed treatment of both views from TPAG.[1] Hence, the TPAG majority view should not be interpreted as the next best alternative to the Authority's proposal.

1.3 Table 1 below summarises alternative options relative to the current framework.

1 Note the number of TPAG members supporting the majority view exceeded by only one the number of members supporting the minority view. Slight changes in the membership of TPAG could well have altered which view was labelled the minority versus majority view.

Table 1 Current and alternative options tested

<table>
<tr><th>Regulated transmission service</th><th>Current</th><th>Authority's Proposal</th><th>Majority TPAG View</th></tr>
<tr><td>Interconnection
(HVAC)</td><td>Charged to each distributor and direct connect consumer on basis of share of Regional Coincident Peak Demand (RCPD)</td><td rowspan="2">Codify that surplus loss and constraint excess (LCE) and surplus financial transmission right (FTR) revenue fund (offset) some of the Interconnection and HVDC charges.

Amount unfunded by FTRs and LCE funded by generators, retailers and direct connect major users on the basis of share of private benefits, as estimated using alternative runs of the scheduling, pricing and dispatch (SPD) model used to settle half hourly trading at multiple price nodes.

A RCPD/RCPI charge would apply to pre 2004 assets (except for pole 2 of the HVDC); assets below the $2m threshold; and any other under-recoveries. The charge would be based on with the number of peaks, and variations in this regionally, determined on the basis of efficiency. The RCPD charge would be levied on distributors, retailers, when distributors opt out, and direct connect customers. There would be a 50:50 split between the amount</td><td>No change, except to remove reactive power draw</td></tr>
<tr><td>HVDC</td><td>Full cost recovered from SI generators apportioned on the basis of historical anytime maximum injection (HAMI)</td><td>Adoption of postage stamp charging with 10-year transition from South Island generators paying for HVDC to postage stamp approach.</td></tr>
</table>

Regulated transmission service	Current	Authority's Proposal	Majority TPAG View
		collected from RCPD and RCPI. A prudent discount policy would be retained but refined.	
Reactive support	Included in interconnection charge	Split from interconnection. Static reactive support costs allocated by Transpower on the basis of aggregate reactive power demand measured at each GXP during RCPD periods. Dynamic reactive support subject to SPD charge and any balance collected through RCPD and RCPI.	As for AUTHORITY'Sproposal except that costs would be allocated by Transpower within Guidelines developed by the Authority
Connection	Allocation of allowed costs using maximum injection (generators) or off-take (distributors)	Closes "loopholes" that currently allow some existing connection assets to be redefined as interconnections assets. Some connection charges also paid from LCE/FTR funds.	No change from current arrangements

2 The overall results of the aggregated analysis, for the central case, are provided in the Table 2 below.

Table 2 Summary of aggregate costs and benefits (central case)

PV of economic costs and benefits	Authority's proposal	Majority TPAG view	Difference
Economic costs	$50.1m	$0.9m	$49.2m
Economic benefits	$223.3m	$50.2	$173.1m
Net economic benefit	$173.2m	$49.3m	$123.9m

3 The breakdown of the net economic benefits for each component of the Authority's proposal and the Majority TPAG view is shown in Table 3 below.

Table 3 Breakdown of aggregate net economic benefits by transmission service (central case)

Net economic benefits (PV)	Authority's proposal	Majority TPAG view	Difference
Interconnection - HVDC	$158.2m	$36.3m	$121.9m
Reactive support	$13.0m	$13.0m	$0.0m
Connection	$2.0m	$0m	$2.0m
Total	$173.2m	$49.3m	$123.9m

4 The key findings are that both TPM reform options are beneficial relative to the status quo, and that the Authority's proposal generates a higher net benefit than the Majority TPAG view. This reflects, in the main, the expectation that a beneficiaries-pay approach for the HVDC and interconnection assets is more likely to exert downward pressure on future wholesale market and transmission costs and prices, compared with either the status quo or adoption of a phased introduction of a postage stamp approach for HVDC charges as proposed by the majority of TPAG members.

5 Transmission pricing influences future wholesale, transmission, and distribution costs only at the margin. Nevertheless, because total annual supply chain costs in the electricity sector are currently running at around $6.5 billion dollars (final price paid by consumers multiplied by quantity of electricity consumed), and have increased over the past 10 years at about 3.8% per cent per annum in real terms, even marginal efficiency improvements can result in material benefits.

6 Over the long term, under the Authority's proposal in the central case, consumer prices for delivered electricity would be slightly lower than otherwise for a given level of service reliability. This would result from lower wholesale prices, lower transmission charges and possibly lower distribution charges (if distributors would otherwise expand their networks and encourage inefficient embedded generation) than otherwise. These reductions would be very modest (barely

observable) for individual customers, even large customers, but material from an economy-wide perspective.

7 This cost benefit analysis is concerned with understanding the real resource impacts of the proposals on the economy as it is the impact on overall economic efficiency and competitiveness that matter for the long-term interests of consumers. The proposals may also have wealth transfers, which are not losses to society. These effects are described in section 6, stakeholder impacts, but are not included in estimating the economic benefits and costs.

8 Although the Authority's proposal is expected to generate higher economic benefits, it is more costly to introduce and operate because it involves dynamic calculation of transmission charges for HVDC and interconnection assets. Table 4 below shows the sensitivity of each option relative to the status quo under pessimistic and optimistic scenarios (excluding reform of reactive and connection transmission service charging rules).

Table 4 Optimistic and pessimistic sensitivity analysis (aggregated)

Sensitivity of economic costs and benefits PV	Authority's (Optimistic)	Authority's proposal (Pessimistic)	TPAG majority view (Optimistic)	TPAG majority view (Pessimistic)
Economic costs	$32.0m	$81.0m	$0.4m	$1.9m
Economic benefits	$300.7m	$166.1m	$68.4m	$34.6m
Net economic benefits	$268.7m	$85.0m	$67.9m	$32.7m

9 Under the optimistic scenario, the net economic benefits of the Authority's proposal significantly exceed the TPAG majority view. The pessimistic case for the Athority's proposal also produces higher net economic benefits than the optimistic scenario for the TPAG majority view.

1 Analysis framework

1.1 A standard CBA framework has been applied to the analysis of the economic benefits and costs of alternative TPM approaches. This standard framework requires the following major steps:

a. problem definition;

b. options identification;

c. baseline forecast;

d. approach to quantifying costs and benefits;

e. quantify costs and benefits (key assumptions and data);

f. assess non-quantifiable factors and uncertainty (sensitivity); and

g. identify the impacts on stakeholders (distributional impacts).

1.2 The first two steps in this cost benefit framework, the problem definition and options identification, are addressed in Chapters four, five and six of the consultation paper. This appendix discusses and shows the results of the remaining steps in the CBA analysis.

1.3 Consistent with the Authority's interpretation of its statutory objective, this CBA analysis assesses the net economic efficiency effects of the alternative TPM approaches. The Authority interprets its statutory objective as requiring it to exercise its functions in section 16 of the Act in ways that, for the long-term benefit of electricity consumers:

a. facilitate or encourage increased competition in the markets for electricity and electricity-related services, taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets;

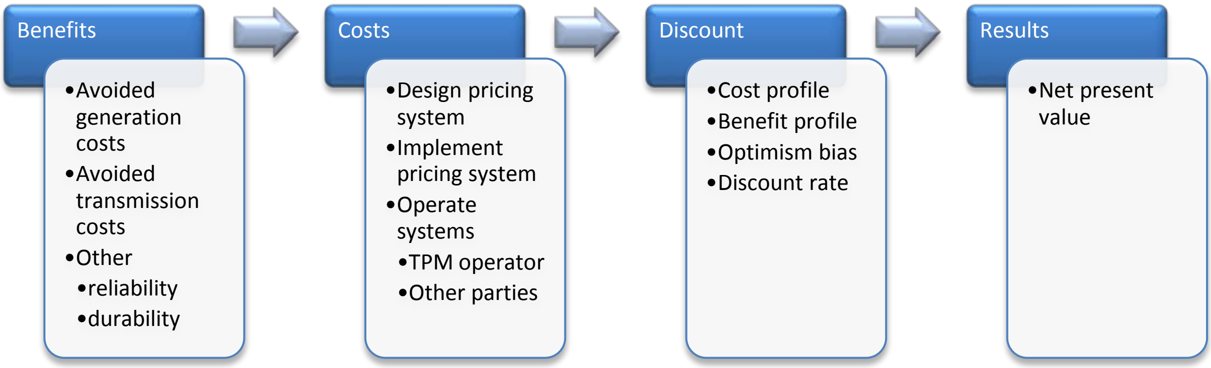
b. encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events; and

c. increase the efficiency of the electricity industry[2], taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation.

1.4 Potential economic benefits and costs are likely to occur over different time periods, with many of the costs incurred upfront and the benefits accruing over time. Hence, estimates of the benefits and the costs will need to be discounted to arrive at a net present value estimate as illustrated in Figure 1 below.

[2] Electricity Authority, Interpretation of the Authority's statutory objective, 14 February 2011.

Figure 1 High level economic costs and benefits



2 Base line forecast and key assumptions

2.1 A baseline forecast is necessary to quantify the impacts of proposed alternative TPM frameworks. This section briefly sets out the baseline forecast used in the present analysis.

Base line historical

2.2 Because of interaction with generation, distribution, and consumption, transmission pricing may potentially impact over the entire electricity sector. Table 5 below provides key data on the size and value of electricity consumption in New Zealand, broken down into the major cost components.

Table 5 Base line historical

Item – all relate to the 2011 calendar year	Value	Unit
Annual generation volume	43,138	GWh
Average wholesale price	67	$/MWh
Residential electricity consumption	12,879	GWh
Commercial electricity consumption	9,146	GWh
Industrial electricity consumption	14,528	GWh
Final price times volume	6,493	$m

Key assumptions

2.3 The key assumptions used in the analysis are as follows:

a. the discount rate applied is 6.01 per cent real, pre-tax, other than for reactive support services. This is the mid-point vanilla Weighted Average Cost of Capital (WACC) as determined by the Commerce Commission for application to Transpower in the 2013 year. We also apply equivalent rates of 4% and 8% for sensitivity. The present value (PV) of costs and benefits are also expressed in pre-tax, real terms;

b. for reactive support services, the NPV estimate from the TPAG August 2011 report has been applied. This is based on a higher discount rate of 8 per cent, real, pre-tax. As a result, the NPV estimate for reactive support services is not strictly comparable with other estimates. The reactive support estimate is under-stated relative to the status quo. The estimate is consistent between the two reform options analysed;

c. implementation costs are assumed to commence in year one of the analysis;

d. benefits are assumed to commence two years following the decision to implement a version of the new TPM,[3] reflecting the time required for regulatory changes, alongside changes to transmission and distributor/retailer billing systems, and the expectation a new TPM would apply from 1 April 2015; and

e. the time period for the analysis is 30 years, with sensitivity analysis around 20 and 40 year periods.

2.4 The baseline assumes there is no incremental cost to continuing with the existing TPM. This does not mean however that there are not costs to continuing with the current TPM. In addition to the on-going operating costs (the options modelled consider the incremental costs of each option), the current TPM has not been accepted by all parties, and has been the subject of on-going and costly disputes including litigation to the High Court.

3 Quantification of costs and benefits

3.1 The TPM is the mechanism by which electricity transmission costs are converted to prices and hence influences both allocative and dynamic efficiency, and by potentially altering operating decisions may also affect productive efficiency:

- productive efficiency means a situation where it would not be possible to produce the same amount of output using fewer inputs or to produce more output with the same amount of input. The extent to which costs of production exceed the minimum amount necessary to produce a given output represents a public detriment because resources which could be deployed productively elsewhere in the economy are used unnecessarily by the inefficient firm.
- allocative efficiency means a situation where it would not be possible to reorganise resources to make some consumers better off without making other consumers worse off. An allocative efficiency loss measures the economic effect of prices being higher than would otherwise occur, for instance, because competition is less intense than it could be. The measure reflects the cost to society of unsatisfied demand or the purchase of a less

[3] Note the method used to quantify benefits means that benefits are initially low and gradually increase over the course of the forecast period.

preferred substitute (and consequently, the diversion of society's scarce resources to producing the less preferred substitutes).

- dynamic efficiency means firms and individuals are aware of changing circumstances and hence they innovate and adapt over time. Dynamic efficiency is associated with the generation of new products, new processes, and new business models; that is, dynamic efficiency involves innovation. Innovation reveals new demand curves for new products ("product innovations"), which generate all of the consumer benefit underneath those new demand curves, and through the use of new, lower cost ways of producing existing products ("process innovations"). Hence gains to consumers from improvements in dynamic efficiency typically exceed by a considerable magnitude gains from productive and allocative efficiency

Quantification of costs and benefits for the HVDC and interconnection

3.2 Chapter four of the Issues paper discusses and identifies the costs associated with the current TPM methodology. Some of these costs of the current arrangements for the HVDC and interconnection are shown in Table 6 below.

Table 6 Some efficiency costs of current TPM

	Authority PV estimate of costs associated with current system[4]
HVDC	
Inefficient generation investment	$30m
Decreased cost of expected HVDC upgrade	-$5m
Inefficient use of grid	$5m
Total costs associated with current HVDC charging regime	**$30m**
Interconnection	
Inefficient decision making (because interconnection charges not commensurate with private benefit)	Up to $72m (medium scenario $20m)
Inefficient investment in electricity export capacity	Up to $50m (medium scenario $30m)
Inefficient investment in electricity import capacity	Up to $48m (medium scenario $20m)
Total opportunity costs associated with current interconnection charging regime	**$67.0m**
Total estimated costs (NPV)	**$97m**

3.3 It is important to emphasise that the modelled efficiencies in the above table are not based on a cost-benefit analysis. For instance the efficiency losses do not capture the avoided dispute costs modelled in this CBA, nor the full set of dynamic efficiency gains modelled in this CBA, nor the benefits associated with the proposed changes to reactive support and connection. Further, the modelled efficiencies do not take into account the incremental costs of adopting the Authority's

4 Note the TPGA modelling applies assumptions that differ from those used in the present modelling and are not directly comparable.

preferred approach. That said the results are comparable in terms of the likely direction of the net benefits rather than the specific values.

The Authority's proposal for the HVDC and interconnection has two main parts:

(1) codify current arrangements for the treatment of loss and constraint excess; and

(2) use the SPD/vSPD models to set beneficiary pays charges.

3.4 The benefits of this proposal is that it:

a. promotes efficient transmission investment through increased transparency of the benefit parties obtain from transmission assets, and by placing stronger incentives on parties identified as beneficiaries to participate in the investment decision-making and approval process;

b. promotes efficient investment by generation and load, as allocating charges to beneficiaries means they will face the transmission cost implications of their investment decisions;

c. promotes allocative efficiency through more efficient prices by reducing deadweight loss, as a greater proportion of the costs of transmission assets, which are currently paid for under the interconnection charge, would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which the charge reflects aggregate benefit;

d. promotes productive efficiency as calculation of the charge can be made contestable; and

e. promotes durability because a robust and justifiable approach is used to determine beneficiaries, who are then charged for the HVDC and interconnection services they receive. This provides flexibility to deal with changes in asset use and configuration and will reduce on-going lobbying for a change to the TPM which will result in savings in expert legal and technical/economic resources and reduce regulatory uncertainty about the TPM.

3.5 The likely costs of the proposal are:

a. implementation costs for both Transpower and participants, including set-up costs involved in implementing the option, including computer equipment, any licence costs, development and testing;

b. operational costs, including the on-going costs of applying the option to estimate the benefits from transmission assets;

c. the costs to participants of using more complex models to verify their transmission charges; and

d. incentives on parties to alter their use of the grid in order to seek to minimise their exposure to the charge, which would be inefficient. This would need to be addressed, to the extent it could be, through the design of the charge or through other mechanisms, such as the prudent discount policy.

3.6 The potential outcomes identified above result from a combination of allocative and dynamic efficiency gains. The primary driver of these gains is through improving the information and incentives affecting a myriad of decisions. Improved information and incentives will likely lead to new and better processes and investment decisions which in turn will raise the level and growth rate of the productivity of the sector in the long run; that is, an improvement in dynamic efficiency. By contrast, the welfare gains that can be achieved through allocative efficiency gains are usually "exceedingly small." As allocative efficiency gains would be achieved through transmission charges better reflecting demand, and the improved incentives and information that would produce this benefit are captured within the estimate of dynamic efficiency, we do not count an allocative efficiency estimate in addition to the dynamic efficiency estimate.

3.7 Quantifying efficiency benefits, especially dynamic benefits, is notoriously difficult, as acknowledged by the New Zealand Commerce Commission and the High Court. Although it is a difficult exercise, competition authorities are frequently called upon to assess dynamic efficiency gains and losses. Typically, one of three different approaches is adopted to estimate efficiency effects from changes to decision rules and incentives, including pricing:

a. estimating the change in consumer surplus from an outward shift of the demand curve; this approach seeks to measure the increase in product innovation (but not process innovation);

b. multiplying the combined allocative and productive inefficiency improvements by a factor on the basis that dynamic efficiency consequences are likely to be greater than allocative and productive efficiencies;[5] and

c. multiplying total revenue by a factor estimated from qualitative information.

3.8 The first approach would seem less suitable for estimating the efficiency effects of change to transmission pricing because the approach primarily attempts to measure a change in product innovation, which for the electricity industry is likely to be significantly less important than process and systems innovation. The approach would also require an estimate of the assumed percentage demand shift, as well as an estimate of demand elasticity. Although estimates of demand elasticity are readily available, we are not aware of any basis for predicting product innovation and converting those predictions into an estimated shift in the demand curve as a result of a TPM change.

3.9 The second approach assumes that potential gains from more efficient investment are a fixed multiple of allocative and productive inefficiencies, which does not reflect the capital intensive nature of the electricity sector, particularly the transmission segment. The Authority does not view the innovation potential of the electricity sector as linked by a certain ratio to the on-going pressures for cost minimization.

3.10 We have therefore applied the third approach; multiplying a sector revenue baseline by a factor estimated from qualitative information. This approach to the quantification of dynamic efficiencies is generally supportable,[6] though when weighting detriments and benefits, allowance needs to be made for the necessarily abstract nature of the exercise.[7] Two judgments are therefore necessary: a) the choice of revenue base and b) the choice of efficiency factor.

3.11 On the first point, a revenue base has been derived from the projected future annual real growth of the electricity sector using the 2011 baseline value of $6,493m set out in Table 5 above. The

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5 This approach was used by the New Zealand Commerce Commission in Decision No 410, *Ruapehu Alpine Lifts Limited and Turora Ski Resort Limited,* 14 November 2000.

6 The approach was used by the New Zealand Commerce Commission in Decision No 511, *Air New Zealand Limited and Qantas Airways Limited,* 23 October 2003 and Decision No. 725, *Cavalier Wool Holdings Limited and New Zealand Wool Services International Limited,* 9 June 2011, and an earlier Decision *Ravensdown Corporation Limited.* In the Air New Zealand and Ravensdown decisions, the Commission used a range of 0.5% to 1.5%, and Cavalier Corporation the Commission used a range of 0% to 1%, with the midpoint of 0.5% as the mostly likely effect. The Commission adopted the lower estimate in the Cavalier decision because it formed the view that in that case, the dynamic efficiency effects" may be very limited" (para 288). All three decisions were appealed to the High Court, with the High Court upholding the Commission's approach in each case.

7 Air New Zealand v Commerce Commission (No 6)/HC/2004, CIV-2003-404-6590), paragraph 313.

projected annual growth factor applied is 3.8 per cent. This is an extrapolation of the real average annual growth observed over the last 10 years.

3.12 The electricity market prices and volumes are sourced from the MED (now the Ministry of Business, Innovation and Employment) data file for energy. 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.

3.13 The observed average annual growth in market size over 2000-2011 is 3.8% (real). Two thirds (67%) of market growth reflects changes in unit prices, with volume effects responsible for the remaining one third. Volume growth has been flat for the past three years. Using a 10 year average of 1.25% annual growth seems a reasonable projection of future growth in volumes.

3.14 Under the selected revenue base, the 2011 baseline is excluded from the efficiency benefit calculation, which is applied only to the projected growth in this baseline, from the 2014 calendar year. This is a conservative revenue baseline, given the fact the beneficiaries-pay pricing regime applies for post 2004 transmission assets (other than pole 2 of the HVDC), rather than to post 2011 transmission assets.[8]

3.15 The chosen efficiency parameter applied for the Authority's proposal is 0.3 per cent. This is equivalent to a reduction in the average unit price per MWh (over total volumes) of $0.12/MWh (or just 0.05 per cent).[9] As a cross check for reasonableness, we reviewed the careful studies completed for the Commerce Commission on changes in total factor productivity in the electricity distribution business. A detailed study undertaken for the Commission in 2009, estimated total factor productivity for this industry segment of 1.4 to 1.5 per cent, and about 2% for the non-exempt segment (which may be more comparable to transmission).[10] That is, the potential lift in sector performance assumed for this cost benefit study resulting from an improved pricing methodology is less than the difference in annual performance between the exempt and non-exempt segments of the electricity distribution sector.

3.16 Similar to the chosen baseline, the choice of efficiency parameter is conservative relative to the efficiency gains applied in the examples cited in footnote 10 above. This conservative judgment reflects the fact that transmission pricing reform would have a relatively limited impact on transmission, generation and distribution costs compared with other market reforms. It also reflects the assessment that New Zealand energy market reforms are well advanced and large efficiency gains from reform have already been achieved.

3.17 As noted in the issues paper, there has been a move to beneficiaries-pay transmission pricing models in some international jurisdictions. These changes were supported by qualitative descriptions of expected benefits similar to the discussion outlined above. However, we were not able to locate a quantitative assessment of benefits obtained, which is not surprising given that the changes are relatively recent and benefits are expected to emerge over the investment cycles of long-life assets.

3.18 There are quantitative analyses available of the benefits from introducing improved co-optimisation of decision-making in the New Zealand electricity sector, and internationally. There

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8 Because of this conservative assumption, the efficiency benefit estimate used here is not considered highly sensitive to the rate of future annual growth in the value of the New Zealand electricity market. If the growth were less than 3.8 per cent over the coming decade, this would not in itself imply that the estimated efficiency benefit value is optimistic.

9 Calculated as either the % change in final price or the estimated benefit over total value of the market.

10 Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2008, 1 September 2009.

are also quantitative estimates of the gains from improved information and incentives due to market reforms, including pricing changes, into the electricity sector.

3.19 A PA Consulting study, prepared for the Commission of Energy Regulation in Ireland, as part of an investigation into reserve markets, explained that the co-optimisation of energy and reserves in New Zealand reduced the costs of reserves from averaging around 10% of wholesale electricity prices to average around 1% of electricity prices.[11] This study also reported gains of similar magnitudes for Singapore and Australian electricity markets.[12]

3.20 In a major United States study in 2006, the Electric Energy Market Competition Taskforce report to the US Congress included a review of 30 individual assessments of market reform benefits undertaken between 2000 and 2005. These studies estimated that reforms that improved the information, incentives and competitive pressures, resulted in gains to consumers often in excess of 5 per cent and in some cases as high as 20 per cent. These price reductions (relative to price levels that might otherwise have occurred) may reflect a combination of wealth transfers and efficiency gains.[13]

3.21 The materiality of the proposed efficiency factor can also be compared with the avoided cost of individual assets and services. For example, if TPM reform avoids construction and operation of a new 200MW gas fired peaking generator in five years' time, the avoided cost (or benefit) would be in the order of NPV$96m. This is on the assumption the plant would operate for the following 20 years with a low utilisation rate of 10 per cent.

3.22 The chosen efficiency parameter for TPAG majority view is 0.065 per cent, or around one fifth of the value of the parameter used for the Authority's proposal. The selection of the TPAG majority view efficiency parameter is based on different considerations from the selection of the parameter used for the Authority's proposal.

3.23 The efficiency parameter for TPAG majority view reflects the assessment that the opportunity cost of current HVDC cost recovery is in the order of PV$30m, as set out in Table 6 above. This has been adjusted to take into account the discount rate and forecast horizon used in the present analysis.

3.24 Table 7 below shows benefits assumptions in the form of more efficient transmission and electricity market outcomes (lower prices and avoided costs) associated with TPM reform of HVDC and interconnection services.

[11] PA Consulting, Commission for Energy Regulation, A Co-Optimised Energy - Reserve Market, Frequently Asked Questions, 28 November 2003, page 1-1.

[12] Ibid.

[13] Efficiency gains from economic reforms of other sector have also been measured at about 5% to 7%, see for example Winston, C (1993), "Economic deregulation: Days of reckoning for microeconomists", Journal of Economic Literature, Vol. 31, September, pp. 1263-89.

Table 7 Benefit quantification (HVDC and interconnection)

HVDC and interconnection benefits (PV)	Percentage of aggregate electricity market growth	Wholesale market benefits	Adjustment for avoided costs of disputes	Gross benefits
Authority's proposal	0.3%	$171.8m	$36.5m	$208.3m
TPAG majority view	0.065%	$37.2m	NA	$37.2m

3.25 The benefits in this table incorporated durability benefits - the avoided costs (benefit) of on-going disputation over the method for allocating transmission charges. These have been modelled in relation to the HVDC and interconnection because the overwhelming majority of the benefits are expected to be attained in relation to moving to a more durable charging regime for these assets.

3.26 The estimated PV $37.2m of avoided transmission dispute costs is based on an estimated annual value of $2.85m. There are two components to this annual value.

a. On-going costs of $1.95m; and

b. Periodic costs of $0.9m.

3.27 The on-going cost estimate of $1.95m is based on an assumed 15 participants (including the EA) engaged in on-going transmission cost allocation disputes. Each party on average has one Full Time Equivalent (FTE) staff member engaged in this activity at a total cost of $130,000 per FTE, inclusive of on-costs.[14]

3.28 The periodic cost estimate of $0.9m is based on the assumption transmission pricing disputes escalate to litigation around every five years and that the cost of litigation for each participant (including the EA) is $300,000. Hence the assumed aggregate cost of a litigation event over 15 participants is assumed to be $4.5m. This value may be compared with the estimated cost of a recent dispute over an Undesirable Trading Situation (UTS) in March 2011, where the total cost of the litigation is likely to have exceeded $4.5m by a significant margin.

3.29 The durability component has not been added to TPAG majority view. This is on the basis that TPAG majority view is unlikely to see a material reduction in disputes over the allocation of transmission charges.

Incremental costs of TPM reform

3.30 Substantial reform of the TPM imposes potential costs necessary to establish and operate the new pricing arrangements. Costs include:

a. development of detailed rules codifying the operation of the new TPM;

b. development of associated IT systems both by the party that implements the TPM and the parties that pay and pass on transmission charges to their customers (principally generators and retailers); and

[14] These are average values. Some parties, such as the Authority itself, could be applying greater resources, while others could be applying lower resources than the simple average.

c. operation of the IT systems by the party responsible for implementing the TPM and by participants.

3.31 Following the adoption of a preferred TPM, there would be costs associated with the detailed design of the adopted TPM into a codified set of rules for creating and modifying on-going regular transmission charges. The extent of these costs is likely to depend on the complexity of pricing design task and opportunity for conflict over key design aspects.

3.32 Under the Authority's proposal, interconnection charges would apply to generators, retailers, major end use customers and distributors (with respect to the RCPD/RCPI residual charge to the extent distributors did not opt-out). They would also apply to distributors to the extent they do not opt out of the TPM, or directly trade in wholesale energy markets. At present, retailers are only indirectly liable for transmission charges via:

a. a transmission component recovered via distributor charges (other than for major direct customers);[15] and

b. mark-ups on generator wholesale offer prices (whether physical or financial) to recover transmission charges (for instance, connection charges or HVDC charges).

Quantification of TPM reform costs

3.33 As with the quantification of TPM reform benefits, quantification of TPM reform costs is subject to a high level of uncertainty over the course of future events and decisions that are inherently unknowable. Reform scope, for example, is a significant area of uncertainty.

3.34 Among other things, TPM reform costs will depend on the extent adopted TPM reform proposals are viewed as legitimate by the participants. Reform costs will also depend on the extent the participants accept reasonable trade-offs between cost, effectiveness and perceptions of equity.

3.35 Against this background, a conservative approach has been adopted to counteract the well-known phenomenon of optimism bias in economic and other types of cost benefit analyses. The estimate of costs set out below may well be excessive and there are significant opportunities to reduce or otherwise manage TPM reform costs by way of effective governance and management of the reform process. The discussion below should be read in the context of testing whether the benefits of reform are likely to outweigh the costs, and not as a rigorous exercise in budgeting TPM reform costs.

3.36 Cost assumptions are based on consideration of:

a. TPM design;

b. transmission pricing system (TPS) development cost;

c. participant TPS development costs (cost per participant and number of participants); and

d. On-going TPS operating costs for both the pricing entity and participants (per participant and number of participants).

One off costs

3.37 Table 8 below summarises the incremental implementation (one off) costs of the two options over the two or three years before the new TPS begins operation.

[15] For retailers on a interpose use of system agreement. Retailers on a conveyance only use of system agreement may not face distribution or transmission charges directly.

Table 8 Incremental one-off costs

Implementation costs (nominal dollars)	Authority's proposal	TPAG majority view
Detailed TPM design and codification	$0.5m	$0.4m
Aggregate central systems	$3.5m	NA
Aggregate participant systems	$1.9m	$0.6m
Total implementation costs	$5.9m	$1.0m

3.38 The implementation cost for participants estimate for the Authority's proposal is based on an average cost per participant of $125,000 and 15 participants. Under TPAG majority view, the average cost per participant is assumed to be $40,000 per participant.

3.39 The basis for the cost estimates in Table 8 is discussed below.

Detailed TPM design (HVDC and Interconnection)

3.40 TPM design is expected to involve addressing a number of matters, summarised below. These matters influence the incremental cost of TPM reform.

- Boundary resolution - The allocation of asset and other costs is a key step in TPM design. There are many primary and secondary assets which are effectively shared between the electrical branches visible to SPD. Therefore a robust and repeatable process for allocating shared assets to branches will be required.
- Real grid to SPD mapping – a method will need to be designed to apportion operating and capex costs associated with physical assets to electrical elements modelled in SPD.
- Counterfactual security limits – a practical and robust method has to be designed to calculate branch security limits for the counter factual case. This would involve both voltage stability and thermal capacity limits.
- Treatment of sequential investments – a method will have to be designed to deal with the situation when an asset is augmented by additional capex. Consideration will have to be given whether to treat the assets as one or treat them separately for the purposes of determining the counterfactual solve.
- Robust VOLL process - Decisions on the derivation of wholesale prices in the counterfactual model that assumes non-supply from remote generation will be required (Value of Lost Load (VOLL) or Short Run Marginal Cost (SRMC) of high cost local generation). Where a counterfactual results in un-served load (at least from remote generation), the value attributed to un-served load will determine the aggregate transmission price for the period in question.
- Legal and policy costs associated with codifying design changes – the Authority would experience legal and policy costs associated with reviewing the design elements and codifying them

3.41 Reflecting the above costs a one-off cost of $0.5m has been applied for the Authority's proposal. A one-off cost of $0.38m has been assumed for TPAG majority view with a lower level of variability. It is further assumed there is no incremental cost for the pricing service provider. This reflects the fact the current pricing system already operates both RCPD and HAMI approaches, and this would continue for the 10 year transition period.

Transmission pricing system implementation

3.42 It is likely the implementation of the Authority's proposal for the HVDC and interconnection would involve development of the information systems to be used for creating and checking monthly or other periodic transmission charges.[16] A number of extensions and changes could be required to wholesale market models to enable them to be used in the manner being contemplated. Some of the possible changes may be significant and are discussed below.

3.43 The party or parties that implement the new TPS could be required to undertake the following tasks and activities:

a. program management costs;

b. service provider contracting;

c. IT system design;

d. hardware, software and communications;

e. strengthening real-time interoperability with SPD and SFT; and

f. software development, testing and auditing.

3.44 Parties that are liable to pay for transmission charges are likely to incur some TPM reform implementation costs. These could include:

a. consultation and participation in the TPS implementation process;

b. consideration and implementation of any strategic response to the new TPS;

c. developing or modifying billing systems, most notably for retailers (or wholesale pricing algorithms for generators), to enable automated recovery of variable transmission charges from end-users currently on time-of-use tariffs, which are mostly commercial customers at this stage;

d. consideration and potential implementation of any changes to existing prudential requirements to address potential risks from a change in transmission counter-parties;

e. developing new systems to enable monitoring and checking periodic transmission charges (most notably for retailers); and

f. communicating the effects of changes to transmission charges to end users (to the extent not already addressed by the Authority or Transpower).

3.45 A total TPS implementation cost of $5.4m has been assumed for the Authority's proposal, with a wide variation around this value. This is based on estimated central systems costs of $3.5m[17] and an aggregate cost for participant systems of $1.9m. These costs reflect a complex information system project, and number of difficult issues to tackle. The participant cost estimate is based on an average cost per liable entity of $125,000, for 15 entities (over an assumed two year implementation period). There could be some variation around the average level for

[16] The Authority is currently progressing the Wholesale Advisory Group's recommendation on improvements to settlement and prudential security arrangements. There may be value aligning the settlement process, including the period of settlement, for Transmission pricing with this process.

[17] By way of comparison, the implementation costs for the central systems for the 2007 reform of the reconciliation system were approximately $2.8 million (2012 dollars) and for the FTR market (2012) were $5.4 million.

individual entities. A reasonable margin is left to allow for the possibility of cost escalation (and see the sensitivity scenarios discussion further below).

3.46 A total cost of $0.6m has been assumed for TPAG majority view with a lower level of variability. This is based on an estimated cost per entity of $40,000. No incremental pricing service provider costs have been explicitly provided for. This is due to the fact that in process terms TPAG majority view does not represent a significant departure from the status quo, whereby transmission prices are already recovered via mixture of RCPD and HAMI methods of cost allocation.

On-going costs

3.47 There would be on-going costs arising from operating the reformed TPM. These would include the cost of any additional staff to operate the reformed TPM to enable:

a. on-going operation of the transmission system billing engine;

b. on-going operation of the systems used by transmission customers to verify transmission charges and recover these costs from downstream users (or from wholesale market sales); and

c. the possibility the TPS could become more complex over time as the number of counterfactuals, including nested counterfactuals, increases.

3.48 A total PV of $44.5m has been assumed for on-going TPS costs associated with the Authority's proposal, with a wide variation around this value. This reflects estimated annual costs of $3.5m, consisting of $1.9m for participants in aggregate and $1.6m for service provider operations. The annual cost per participant reflects an estimated cost per entity of $125,000 for 15 participants.

3.49 There are no additional on-going costs assumed for TPAG majority view versus the status quo.

Quantification of costs and benefits for reactive support

3.50 The PV of potential avoided costs (benefit) from allocating the cost of reactive support services in a more targeted way are shown in Table 9 below. The amounts identified by TPAG are used for both the TPAG majority proposal [18] and the Authority's proposal.

Table 9 Net benefits of change to cost recovery for reactive support

Reactive support (NPV)	Optimistic	Central case	Pessimistic
Authority's proposal	$20.0m	$13.0m	$6m
Majority TPAG View	$20.0m	$13.0m	$6m

Quantification of costs and benefits for connection

3.51 The EA's proposal contains some minor amendments to the TPM to restrict the ability of parties to shift connection charges into the interconnection charge. These problems reflect relatively minor drafting deficiencies (loopholes) in the current TPM. It is assumed for present purposes

[18] Note that the TPAG agreed unanimously on their findings and recommendations on reactive support. Hence on this matter the "majority view" was the view of the group. See page 10 of TPAG's Transmission pricing analysis report to the Electricity Authority, dated 31 August 2011. The PV$13m is not comparable with PV values used elsewhere in the present analysis, due to differences in the discount rate and forecast horizon applied.

that tightening of existing rules that define the boundary between connection and interconnection services would result in a small efficiency gain with a PV of $2m. This is shown in Table 10 below.

Table 10 Net benefits of change to connection cost recovery rules

Connection charges (NPV)	Net Economic benefits
Authority's proposal	$2.0m
Majority TPAG View	N/A

3.52 No economic benefits are shown for the TPAG majority proposal because they did not propose any changes to the current connection charges

Overall comparison of quantifiable outcomes

3.53 This section shows the costs and benefits and net benefits for the entire Authority's proposal package and the entire TPAG proposal package.

3.54 Table 11 below summarises the assumed PV of one-off development costs associated with reform of the TPM.

Table 11 PV of TPS development costs[19]

PV of development costs	Pricing design	Pricing implementation (central systems)	Participant implementation	Totals
Authority's proposal (central)	$0.5m	$3.3m	$1.8m	$5.6m
TPAG majority view (central)	$0.4m	$0m	$0.6m	$0.9m[20]

3.55 Table 12 below shows the assumed PV of on-going costs associated with adopting a new TPM.

Table 12 PV of on-going costs

PV of on-going costs	Pricing party	Participant parties	Totals
Authority's proposal (central)	$20.5m	$24.0m	$44.5m
TPAG majority view (central)	0	0	0

[19] The figures presented in this table 11 are present value estimates and hence are slightly less than the nominal figures presented in table 8.

[20] Some totals may not add up precisely due to rounding.

3.56 No costs are identified for introducing changes to reactive support and connection. For reactive support this is because the costs are incorporated in the net benefit calculation. For connection this is because the costs of the Authority's proposal in this regard are minimal. The cost estimates for the Authority's proposal are based on the assumption that participants are likely to outsource assurance on the calculations used to determine transmission charges and that this provides significant scale economies.

3.57 Table 13 below compares the PV of costs and benefits for the two options analysed, using a central case. This shows that, while the TPAG majority view could be expected to generate a net benefit, the net benefit from the Authority's proposal is greater.

Table 13 PV of aggregate costs and benefits relative to baseline (central case)

PV of aggregate costs and benefits	Authority's proposal	TPAG majority view	Difference
Costs	$50.1m	$0.9m	$49.2m
Benefits	$223.3m	$50.2m	$173.1m
Net benefit	$173.2m	$49.3m	$123.9m

4 Non-quantifiable factors and uncertainty

4.1 This section discusses how the two alternative TPM reform options compare under uncertainty over both benefits and costs.

4.2 An inherent feature of estimating dynamic efficiency is that it is necessarily an abstract exercise. This feature becomes more important when the estimated costs and benefits are very close, which is not the case with the Authority's proposal. For the Authority's proposal to breakeven, on the central case, an assumed overall efficiency gain (avoided cost) of no less than 0.03 per cent is required over the forecast period. This is equivalent to an avoided cost of 1.8cents/MWh.

4.3 While the net benefits of the Authority's proposal are estimated to be materially greater than for TPAG majority view, the sensitivity analysis reflects significant uncertainty regarding the following:

a. the extent of benefits that can be reasonably expected from adopting the Authority's proposal; and

b. the cost of developing and implementing the Authority's proposal; the high case reflects the possibility that the Authority's proposal entails the development, maintenance (including incremental data entry) and on-going management of a large and complex set of counterfactual market models for various combinations of transmission assets.

4.4 There is potential for disputes over the transmission price outcomes under the Authority's proposal (and a continuation of disputation under TPAG majority view). This relates to possible uncertainty over the validity of estimating the benefits to market participants based on alternative runs of the SPD model, given there are multiple variables that affect wholesale market outcomes, in addition to the configuration of the transmission system. This risk could, however, be mitigated in the course of detailed TPM design.

4.5 The Authority's proposal may not recognise the diverse benefits from the transmission investment. Building a transmission line can increase network capacity by more than the capacity of the line because of network effects, reducing system losses. It may also decrease capacity in some part of the system. Increased capacity can reduce market power and increase system reliability. It may also alter the reserves market (for example the reserves required for a monopole HVDC would be significant compared to a bi-pole). The second pole also increases the overall system flexibility to deal with contingency events elsewhere. Technical control equipment installed with Pole 3 may also improve the efficiency and competitiveness of the ancillary services markets. These benefits may not be amenable to estimation using SPD as they may only arise in a more complicated scenario (i.e. involving more assets than the one isolated for calculation).

4.6 Table 14 below compares the PV of the costs and benefits of the two options for reform of HVDC and interconnection services, using two alternative sets of assumptions (compared with the results in Table 13 above). Under the optimistic case, costs are low and benefits are high, while under the pessimistic case benefits are low while costs are high. This sensitivity analysis illustrates that, under the pessimistic case, the net benefit from the Authority's proposal continues to be higher than for TPAG majority view.

Table 14 Sensitivity results of aggregate costs and benefits

Sensitivity of PV of costs and benefits	Authority's proposal (Optimistic)	Authority's proposal (Pessimistic)	TPAG majority view (Optimistic)	TPAG majority view (Pessimistic)
Costs	$32.0m	$81.0m	$0.4m	$1.9m
Benefits	$300.7m	$166.1m	$68.4m	$34.6m
Net benefits	$268.7m	$85.0m	$67.9m	$32.7m

4.7 The optimistic and pessimistic cases are developed by changing the percentage benefits in the order of +/-30%. The implementation and design costs are changed by similar magnitudes for the Authority's proposal; but a greater variance is allowed to TPAG majority view, off a much lower base. For the Authority's proposal, the on-going costs are a function both of the number of participants affected and the estimated costs per participant (largely labour costs). Because both parameters are uncertain, the potential on-going costs might vary considerably.

4.8 Sensitivity to number of transmission pricing participants Table 15 below shows the impact of doubling the number of liable parties for dynamic transmission pricing from 15 to 30. This reflects a scenario where the Authority's proposal is applied to distributors, rather than to retailers and distributors that trade in wholesale markets. The assumed costs per participant are the same as in the central scenario for the Authority's proposal set out in Table 13 above. The increase in liable parties is assumed to increase aggregate costs to PV$75.92m (an increase of $25.8m). The net benefit decreases by the same amount, or a reduction of 14.9 per cent compared with the central case for the Authority's proposal.

Table 15 Sensitivity of central case to number of transmission pricing participants

Sensitivity of PV of costs and benefits of Authority's proposal	Authority's proposal central case (15 participants	Authority's proposal central case (30 participants)	Difference
Costs	$50.1m	$75.9m	$25.8m
Benefits	$223.3m	$223.3m	-
Net benefits	$173.2m	$147.4m	($25.8)

4.9 The increase in costs in Table 15 (for the 30 participant case) assumes that distributors would need to develop and operate sophisticated systems to pass-on dynamic transmission charges to relevant retailers and possibly some large end users. It is likely to overestimate the costs because in such a scenario a third party commercial operator would likely provide joint services to distributors and possibly other parties, reducing costs.

4.10 Furthermore, another scenario would be where distributors opt for a simple approach and simply smear dynamic transmission charges, for example by reverting to a postage stamp method of transmission cost recovery from retailers. In such a case, however, the net benefits set out in Table 13 for the Authority's proposal would not be the same because TPM reform would not improve integration between transmission and wholesale markets to the extent assumed in the estimate of benefits for the Authority's proposal.

4.11 Note the 30 participant scenario relates only to the participants in the dynamic component of transmission pricing. If the residual component continued to fall on distributors and used a relatively straightforward, static approach, then no incremental cost would be incurred. In this circumstance, the lower base case estimate would apply.

Sensitivity to discount rate (aggregate)

4.12 If a higher discount rate of 8% (pre-tax, real) were applied, the Authority's proposal remains the preferred option in NPV terms. Both projects remain NPV positive. This is shown in Table 16 below. The discount rate would have to be greater than 56.6% for the Authority's proposal to have a negative NPV outcome.

Table 16 Sensitivity to discount rate

Sensitivity to alternate discount rate (NPV)	Authority's proposal	TPAG majority view
4.0% discount rate	$245.6	$65.5
6.01% discount rate	$173.2m	$49.3m
8% discount rate	$126.4m	$38.8m

Sensitivity to time period

4.13 The Authority's proposal remains the preferred option when the time period for operation of the new methodology is allowed to vary by +/- 10 years. Table 17 shows the results. The Authority's proposal has a pay-back period of 6 years.

Table 17 Sensitivity to time period (aggregate, NPV)

Sensitivity to alternate time periods (NPV)	Authority's proposal	TPAG majority view
20 years	$97.2m	$32.3m
30 years	$173.2m	$49.3m
40 years	$246.4m	$68.6m

5 Stakeholder impacts

5.1 The analysis presented earlier sets out the overall economic costs and benefits of two options for TPM reform. This section describes the stakeholder impacts for the EA's proposal relative to the status quo. The great majority of the impacts relate to the proposal for the HVDC and interconnection assets. The costs and benefits for stakeholders are consistent with (and do not add to or subtract from) the economic costs and benefits described earlier.

5.2 The key stakeholder impacts of the Authority's proposal, compared with the status quo, are as follows:

a. Over the long term, consumer prices for delivered electricity would be slightly lower than otherwise for a given level of service reliability in both lower generation cost (e.g.SI) and higher generation cost regions (e.g. NI). This would result from lower wholesale prices, lower transmission charges and possibly lower distribution charges (if distributors would otherwise expand their networks and encourage inefficient embedded generation) than otherwise. These reductions would be very modest (barely observable) for individual customers, even large customers, but material from an economy wide perspective. To this extent, the proposal would contribute to overall economic efficiency and competitiveness. It should be noted that some portion of the lower wholesale price will be a wealth transfer from generators. The majority of the reduction in wholesale prices is, however, attributable to real efficiency gains.

b. Retailers would become directly liable to pay transmission charges, whereas at present retailers are only indirectly liable. As discussed in section 3, this is likely to require retailers to modify their billing systems to ensure efficient cost recovery of transmission charges, incorporating a high level of variability within a year. Other costs could involve development and operation of options to smooth variable transmission charges.

c. Generators are likely to contribute a higher share of transmission charges than currently. They may need to modify their wholesale pricing algorithms and strategies to recover these costs, to the extent permitted by competition. Higher cost generators, benefiting by being dispatched due to transmission upgrades, may pay higher average unit prices for transmission capacity compared with lower cost generators.

d. The proposal is broadly neutral in terms of the value of Transpower's asset base since this is indirectly related to price regulation (on the assumption aggregate transmission charges are capped to provide for no more than efficient cost recovery). The proposal could both increase and decrease demand for Transpower's services (and associated assets) in the future. Transpower may incur additional operational costs associated with implementing and operating a new pricing methodology. Transpower may potentially have a higher risk (along with the Authority) of being drawn into any disputes over transmission charges arising from issues around the estimation of relative benefits from transmission. The proposed pricing methodology may also have implications for the work of the Commerce Commission.

e. Retailers and direct connections in the North Island may contribute a higher share of HVDC transmission service charges than currently, depending on how these charges are being passed on by generators. At the same time, retailers and direct connections in the North Island could see reductions in wholesale costs that at least exceed increases in their transmission charges.

f. South Island generators (and in future generators upstream from transmission constraints that can be viably upgraded) could experience increases in sales volumes and average sales prices. They could also have lower transmission charges than otherwise.

g. Distributors and direct connections with poor power factors would have modest increases transmission charges (offsetting reductions for the majority of liable parties would be modest).

5.3 The analysis supports the view that the proposal would result in real efficiency gains, not merely wealth transfers. It also supports the view that the net benefits are likely to be material.