# Beneficiaries-pay options

## Advice to MEUG regarding Electricity Authority Beneficiaries-pay options working paper (21 January 2014)

NZIER report to MEUG

March 2014

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# Authorship

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# Key points

The Electricity Authority (EA) has released a series of working papers that are aimed at responding to matters raised by stakeholders in response to the EA 2012 Transmission pricing proposal. The EA remain of the view that there are more efficient ways of pricing transmission services than the status quo and have proposed a number of options on how to apply their preferred beneficiaries pays (B-P) charging mechanism.

## What options are they proposing?

- Simplify the calculation parameters in the SPD model of benefits
  - Fewer assets in the calculation base
  - Longer capping period – daily vs half hour
  - Calculate using gross benefits
  - Include a nominal demand response
  - Modify some of the Transmission Pricing Methodology processes (eg: invoice annually with rates set in advance of billing)
- Use GIT criteria to allocate specific "reliability investment" assets to beneficiaries, in tandem with a simplified SPD calculation
- Divide NZ up into a number of charging zones, calculate inter-zone charges using the simplified SPD model and intra-zone charges via flat tax.

## NZIER assessment

Analysis shows incidence of overall transmission charges is very sensitive to how residual charges are allocated – that is those charges not captured in a beneficiary-pays charge. It is hard to see how a full assessment of the B-P mechanism can be made independent of options for allocating the residual and how the moving parts all interact.

Specific comments are as follows:

- We are pleased that the EA has acknowledged the importance of demand response and intends taking account of demand elasticity and dispatchable demand. Both are good moves in the right direction by the EA, though some further refinement is needed.
- The EA approach to non-supply is sensible, in principle, and a considerable improvement upon a blanket value of $3,000/MWh as proposed. Their revised approach has the potential benefit of causing prices for non-supply to be adjusted dynamically and thus to reflect the changing value of interconnection over time.
- Charging based on net benefit has some merit. The EA should consider whether its concerns about inefficiencies from charging on net benefits are of much practical consequence.
- Compensation for dis-benefits is, however, highly inefficient as it encourages inefficient production and investment.

- We have considered an in-principle basis for charging embedded generation. It is clear that efficient charging of industrial cogeneration will need to be based on net injection (as suggested by the EA). Finding the most efficient charging basis for other embedded generation will be more challenging.
- A GIT-based charge shifts (some) costs of transmission from obvious non-beneficiaries to a set of possible and probable beneficiaries. This is potentially an improvement on the status quo in terms of investment and dynamic efficiency. It will, however, come with costs associated with the fact that it is not well targeted. Whether it is an efficient TPM option is a matter of trade-offs and needs to be compared against alternative charging approaches or components of a transmission pricing methodology. The materiality of these considerations is, in part, an empirical matter. These issues should be considered in the context of cost-benefit-analysis of a full transmission pricing proposal.

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## Tables

# 1. Scope of the paper and of this assessment

The Electricity Authority (EA) has released a working paper outlining options for beneficiary-pays (B-P) components of a transmission pricing methodology (TPM). This report assesses the options put forward in the report.

The B-P paper is the fifth in a series of working papers aimed at responding to matters raised by stakeholders in response to the EA's 2012 Transmission pricing proposal. The EA is separating out the "subject areas" that were brought to its attention and deal with the matters raised on a subject-by-subject basis rather than as an interconnected full-proposal.

## What is the problem they are addressing?

The working paper is aimed at improvements over the status quo transmission pricing methodology. The EA remain of the view that there are more efficient ways of pricing transmission services than the status quo. Problems with the status quo remain as discussed in the EA's 2012 proposal– how to efficiently price to recover costs of past transmission investment, to encourage efficient investment decisions and to minimise free riding of use of the transmission grid.

The focus of the B-P paper is on whether any of the B-P options are fit for purpose or if not how they can be improved. Full analysis of the options, alongside other elements of a TPM, will come later.

The relationship between the B-P paper and the wider TPM is illustrated in Table 1, with reference to key issues we raised in response to the EA's 2012 proposal. Most of the issues raised previously were cross-cutting issues which cannot be addressed in the B-P paper's scope.

## What options are discussed in the paper?

- Simplify the calculation parameters in the SPD model
  - Fewer assets in the calculation base
  - Longer capping period – daily vs half hour
  - Calculate using gross benefits
  - Include a nominal demand response
  - Modify some of the TPM processes (e.g. invoice annually in advance)
- Use GIT criteria to allocate costs of specific "reliability investment" assets to beneficiaries, in tandem with the simplified SPD model
- Divide NZ up into a number of charging zones, calculate <u>inter</u>-zone charges using the simplified SPD model and set <u>intra</u>-zone charges as a flat tax.

### Table 1 EA 2012 proposal vs 2014 B-P

| NZIER 2012 key concerns | EA 2014 B-P proposals |
|---|---|
| CBA not well evidenced with some circular logic. | Qualitative assessment of net benefits of different B-P options. Otherwise, not addressed in this paper. |
| One pricing fix for 3 problems:<br>- Sunk cost recovery<br>- Investment incentives<br>- Minimise free riding. | Not directly addressed in this paper. Yet to be demonstrated if a second, GIT-based, charging regime would be an improvement. |
| Benefit-based charging needs to be integrated into wider regulatory system. | Partially addressed with GIT-based charges improving links to regulatory regime. Yet to be seen if this is a beneficial approach. |
| No demand response factored in. | Addressed but improvements needed. |
| Benefit-based charges are a small part of charges. | Minor improvements – excluding GIT-based charges which are only crudely benefits-based. |
| Potentially inefficient (gross) basis for calculating benefit to embedded generation. | Some suggestion of change but lack of clarity. |
| Structural flaws in benefit calculation methods e.g. ½ hour capping and implausible cost of non-supply. | Largely addressed through e.g. daily capping and differentiated values for costs of non-supply. A few improvements still needed. |
| Pass-through of residual charges will limit dynamic efficiency gains. | Not addressed in this paper. |

Source: NZIER

## 1.1. Our approach

Rather than revisit the in-principle and high level assessments that we included in our February 2013 advice to MEUG on the EA 2012 TPM proposal, this analysis and assessment focusses on specific issues to do with the options in the B-P paper. We caution that our assessments do not relate to other aspects of transmission pricing that were the subject of previous EA working papers, or papers yet to come.

We are pleased to see that a number of our concerns have been addressed by the EA but we remain concerned that most of the core matters that we felt could be improved upon remain built into the 'simplified SDP' in this B-P working paper.

## 1.2. Scope of this assessment

### The broader view

The options the EA offers in this standalone B-P paper are mainly to do with choices of how the moving parts within the options work, rather than dealing with the in-principle issues that need to be resolved if the new TPM is to be efficient and durable. Having said that, the B-P mechanism is a key piece of the transmission pricing puzzle and we believe that it should be evaluated on its merits.

### The moving parts in the B-P options

MEUG have asked us to evaluate the changes that the EA have made to the 2012 proposal to see if the B-P options in the new proposal improve on the original and whether they adequately address issues we raised in 2013. In the absence of a comprehensive view of the full pricing method, due later in 2014, we have restricted our analysis and assessment to the proposed B-P options and how the moving parts within each option work.

Specific matters that we have considered are the main changes that the EA appear to have made:

- Key design parameters for each B-P option
  - Assets included/not included
  - Daily capping period
  - Demand side responses
  - Non supply values
  - Setting charges ex-ante
- Charge on gross or net benefits
- The treatment of embedded generation
- Inclusion of benefits to providers of instantaneous reserve (IR)
- Who gets charged – retailers or distributors
- Explicit consideration of reliability investments – inclusion of a GIT charge

# 2. Our analysis and assessment

What are the B-P options, how do they work and are they likely to be beneficial.

## 2.1. Simplified SPD

The EA have made a number of changes to the 2012 transmission pricing proposal in an effort to make it easier to understand and reduce uncertainty regarding the charges transmission users will face. The EA propose to;

- have Transpower credit the loss and constraint excess (LCE) for interconnection assets against interconnection revenue requirements as opposed to attributing these funds to links in the transmission grid
- use the SPD model and wholesale market data to solve for final prices and identify beneficiaries of transmission assets as before, though with some model parameters changed
- apply the SPD model to a different set of assets;
  - HVDC Pole 2
  - Investments added to Transpower's RAB between May 2004 and October 2012 with a cost greater than $50m
  - Investments added to Transpower's RAB after October 2012 with a cost greater than $20m
- charge generators, retailers and direct connect customers yearly, at rates set in advance, by an amount calculated using the previous 3 years market data, by node, that is smoothed to substantially remove variability
- charge embedded generation schemes larger than 10MW capacity based on the schemes labelled capacity
- decide later whether to charge embedded generation on gross or net injection
- decide later on how to collect any residual cost not covered by a B-P charge (referred to below as residual or residual revenue)
- decide later whether to charge on the basis of gross benefits or to recognise dis-benefits

The simplified SPD model and methodology will work much in the same way as proposed in 2012 by the EA, though the differences in the model parameters and the included assets makes the outcomes somewhat different to the 2012 proposal.

## 2.2. Direct incidence of proposed charges

The direct effects of the changes to the SPD calculation are a reduction in the amount captured by the B-P component (simply because there are fewer assets in the calculation process) that is offset by an increase in the amount captured because the benefits capping period is extended from half hourly to daily. Compared to the status quo charging approach, consumers will initially see lower charges under the simple SPD, though the final level of these charges will depend on how the EA decides to allocate the residual revenue. Generators will face higher charges than they currently do though their share of the B-P component is materially smaller than under the 2012 proposal. It is unclear how much of a cost increase will be faced by consumers with grid connected generation. Table 2 below describes the charges in the same format as Table 2 of our February 2013 advice to MEUG.

### Table 2 Direct incidence of interconnection charges (Simplified SPD)

UNI = Upper North Island, LNI = Lower North Island, USI = Upper South Island, LSI = Lower South Island.

| | Status Quo 2012/13 | Status Quo 2015/16 | 2012 Proposal 2015/16 | 2014 B-P paper 2016/17* | 2014 B-P paper 2016/17** |
|---|---|---|---|---|---|
| | **$m p.a.** | **$m p.a.** | **$m p.a.** | **$m p.a.** | **$m p.a.** |
| **Load total** | 555 | 733 | 476 | 478 | 645 |
| **UNI** | 187 | 247 | 162 | 191 | 258 |
| **LNI** | 183 | 242 | 157 | 133 | 179 |
| **USI** | 91 | 120 | 76 | 54 | 73 |
| **LSI** | 94 | 124 | 80 | 101 | 136 |
| **Generation Total** | 126 | 167 | 424 | 365 | 194 |
| **UNI** | 0 | 0 | 86 | 33 | 18 |
| **LNI** | 0 | 0 | 167 | 120 | 64 |
| **USI** | 66 | 87 | 83 | 83 | 44 |
| **LSI** | 60 | 80 | 88 | 129 | 68 |
| **Total** | 681 | 901 | 900 | 844 | 839 |

Source: NZIER calculations from EA data

* Residual allocated 50% each to Load and Generation, excludes LCE

** Residual allocated to Load and Generation using EA estimate of nodal RCPD/RCPI MWh, excludes LCE

Table 2 provides an indication of changes to the direct incidence of interconnection charges as a consequence of the proposed simplified SPD, compared with the status quo for 2013 and 2016 and the 2012 TPM proposal (which had the residual allocated 50:50 to generation and load).

The shaded columns describe two variations of the simple SPD with the residual allocated using two methods – the first is a 50:50 split between load and generation, as before, while the second uses the RCPD/RCPI charge (converted to a MWh charge as the EA included in their modelling results). This analysis serves to show just how sensitive the overall charges are to how the residual is allocated as well as how the charges fall between regions. On this basis it is hard to see how a full assessment of the B-P mechanism can be made independent of options for the residual mechanism and how the moving parts all interact.

As before, under the simple SPD method (and using the 50:50 residual allocation), embedded generation can face some very high charges on a per (gross) MWh basis if gross injection is limited to periods where prices are high.

## 2.3. Assessment of the simple SPD

So, is the simplified SPD B-P charge really that simple and easy to understand and does it overcome the short-comings that were inherent in the 2012 version?

We don't think so.

The EA proposes to make two material changes and several minor modifications to alleviate concerns with the earlier version but we believe that more substantial improvement is required if the B-P mechanism is to be effective in delivering intended efficiency improvements and avoid unintended outcomes.

### 2.3.1. Daily capping

The change that the EA have made from half hourly to daily capping has the intended outcome of linking more of the cost of transmission to benefits. We suggested in 2012 that such a move was necessary to increase the revenue collection from benefit charges and to limit the opportunities to avoid benefit based charges.

Table 3 Benefit charges – simple SPD

| | Load | Generation | Total |
|---|---|---|---|
| Half hourly cap | $100m | $41m | $141m |
| Daily cap | $153m | $41m | $194m |
| 2012 half hourly cap | $104m | $44m | $148m |

Source: NZIER calculations from EA data

### 2.3.2. Included assets

The EA has raised the threshold for the value of the assets that are to be included in the B-P calculation which has the effect of reducing the amount of revenue that is collected from benefit charges. The revenue requirement for each major investment over the $50m threshold has been assessed by the EA based on information from Transpower and presumably that the balance of the revenue required each year is the MAR, set by the Commerce Commission.

The pool of assets that are included in the B-P calculation is not materially smaller than the 2012 original proposal – Table 3 above gives an indication of the materiality of the impact under half hourly capping ($148 - $141m = $7m lower B-P charges).

We note that HVDC Pole 2 is still included in the schedule of assets. Our previous concerns with this matter remain.

### 2.3.3. Demand side response

We had considerable concern with the EA 2012 approach to calculating consumer benefits because demand response (a downward sloping demand curve) should have been used in the calculation of consumer benefits to avoid overstating benefits. The EA has acknowledged this and has considered a notional demand elasticity of 0.01% and noted that that in future empirical estimation and dispatchable demand bids will be used to evaluate demand response. Both are good moves in the right direction by the EA.

The notional elasticity of demand proposed by the EA is small when considering the material impact on benefits that the elasticity assumption can have. We attached an appendix to our advice to MEUG concerning the 2012 proposal that, in brief, suggested the EA use long run elasticity in the calculation concerning sunk assets and a short run elasticity for future investments. This will facilitate a more reasonable transition to equilibrium over time than would the arbitrary use of just a short run elasticity (-0.01). Consumers can and will make changes in response to transmission charges, in the same way that they do with market pricing that they consider to be higher than they can bear. The EA should investigate the use of longer run (larger) demand elasticity parameters.

The EA has provided two options for taking account of dispatchable demand bids. One is based on actual bids which are dispatched. The other is to use fixed bids, possibly based on historical observations.

In terms of the first option, the EA is cautious about using dispatchable demand bids to infer demand response if those bids have not been dispatched in practice. The EA's caution is well-founded. Allowing all bids to be used as an indication of demand response would mean bids would be constructed to avoid transmission charges with no practical implication for the bidder as demand is only 'dispatched' in the counterfactual.

It would be possible to overcome this problem through a combination of default bids, based on historical observation of dispatched bids, plus actual bids which are dispatched. In other words, the options could both be implemented, rather than one or the other.

Combining these options would be a valuable improvement because it would make use of market information on actual demand response, exhibited in bids over time, and thus provide a much better reflection of consumer benefits or willingness to pay than just about any other approach to estimating demand response. Use of a short term bids, where actually dispatched, would help to improve the short term accuracy of benefit calculations by considering short term shifts in market conditions.[1]

### 2.3.4. Price of non-supply

Beneficiary pays charges need to be calculated for periods where the absence of a transmission asset results in non-supply. The EA suggests this price should reflect the cost of investing in alternative sources of supply. The EA notes that the cost of alternative sources of supply depends on location of a node and the frequency of

[1] The idea is that a response curve is modelled in general and the curve could be shifted in or out during benefit calculations based on actual dispatched bids.

non-supply events at that node and that calculations of costs of non-supply should take this into account by considering the frequency of non-supply. Specifically, the more frequent the non-supply events the lower the cost of alternative sources of supply. The EA refers to frequency of non-supply in terms of 'capacity factor' for alternative investments.

This is a sensible approach, in principle, and a considerable improvement upon a blanket value for non-supply events (e.g. $3,000/MWh as proposed). This new approach has the potential benefit of causing prices for non-supply to be adjusted dynamically and thus to reflect the changing value of interconnection over time. The overall net benefit of such an approach would likely depend on:

- the degree of detail used to establish benchmark investment costs – assuming that more detailed or nuanced calculations are more likely to reflect actual benefits
- the duration over which non-supply events are considered
- the potential benefits of frequent updating of capacity factors, to reflect changes in market conditions and therefore actual benefits
- the costs of conducting or updating these calculations.

When considering benchmark investment costs or costs of alternative sources of supply, the EA should also investigate extending the calculations to take account of capacity of existing local sources of supply.

Non-supply events may occur in SPD modelling partly because market offers reflect a state of the world in which non-supply events are unlikely. When calculating costs of supply alternatives the EA could investigate the extent to which a change in offers (availability) of local generation could, in principle, prevent non-supply. This could be done by calculating the potential level of local generation. If local supply could potentially prevent non-supply then typical pricing (offers) of that generation may provide a more efficient signal of non-supply costs. If local generation cannot prevent non-supply, the relevant cost would then remain the cost of hypothetical alternative investment.

### 2.3.5. Setting charges ex ante

The EA has made a material adjustment to the charging regime for B-P, changing from monthly charging ex post to now propose yearly charging ex ante with the charge based on the rolling average monthly charge of the previous 3 to 5 years. This adjustment is in response to stakeholder concerns that, in some cases, the 2012 proposal will result in unacceptable volatility from variations in wholesale market prices compounded by the potential for volatility that is inherent in the B-P SPD mechanism.

We have concerns that masking the real world effects of the wholesale market dynamics is defeating the purpose of calculating benefits in real time. It feels like something of an administrative solution to the concerns of some stakeholders and it has the potential to cause commercial difficulties when transmission charges are out of sync with wholesale market levels. The B-P mechanism is founded on a party's willingness to pay for a service that has a benefit to them. If the direct connection between the benefit and the charge is muted by a time lapse delay we would question whether this will generate a level of dissatisfaction with a B-P charging regime that is greater than with the current TPM.

The success of the SPD approach to transmission pricing is contingent on there being improvements in dynamic efficiency. This will come from participants responding to the signals that come from the connection between their use of the transmission grid and the charges they see. The long delay period proposed for the charging mechanism will likely have the effect of muting this connection and putting dynamic gains at risk.

### 2.3.6. Instantaneous reserves

The EA has proposed expanding the coverage of an SPD-based beneficiaries charge to include providers of instantaneous reserve (IR). This is a potentially useful addition if it widens the scope of coverage of an efficient beneficiary pays charge and thus reduces the quantum of cost that must be recovered through less well-targeted instruments.

### 2.3.7. Gross or net benefits

The EA has considered options for beneficiary-based charges based on 3 different options:

- charges for gross benefits only, ignoring any costs
- charges for net benefits, after deducting costs
- charges for net benefits and rebates or payments for net costs.

A move to net benefits has short term advantages and offsetting long term disadvantages – depending on whether a rebate or compensation payment is made.

The main advantages are that net benefits are what matter to grid customers and which will affect decisions to support investment decisions of the grid owner. In this respect, net benefits are the best basis for supporting dynamically efficient transmission investment decisions.

The disadvantage of net benefits is that it may support inefficient investment and production decisions by grid customers and consumer. The EA considers that a net benefits charge without compensation payments is unlikely to be beneficial because it would incentivise ‘inefficient’ vertical integration. It is not clear from the EA’s reasoning whether this consideration should be given such importance as to discount the net benefits approach altogether. This question requires further investigation.

A net benefits charge which includes compensation is equally if not more likely to be inefficient as compared to a net benefits charge without compensation. If efficient transmission investment causes relative price changes, ‘losers’ should not be compensated through price changes. This sort of compensation – volume based subsidies – is highly inefficient as it encourages inefficient production and investment.

Say, for example, a new geothermal field was found north of Auckland and a decision is taken to invest in new transmission capacity to give consumers cheap access to this energy (because it will be net beneficial to consumers). This would mark a move in relative prices against generation and load elsewhere in the country. Investment in load and generation should increase in Auckland and Northland and decrease elsewhere – other things being equal. A payment to losers would retard this process and reduce the benefits to consumers from access to new fuel sources.

### 2.3.8. Who to charge

The EA has a mixed view as to whether distribution network companies or retailers should face transmission charges under the B-P approach. They cite a range of pro's and con's for each option, that are concerned with transaction costs, 'familiarity with/interest in' the wholesale market and the SPD model, 'ability to/interest in' passing B-P charges through to consumers without any scrutiny and whether they are transmission customers currently or not.

We are reasonably agnostic as to who is charged for transmission services so long as the objectives of using the B-P mechanism are met. Applying the same reasoning for the charging period (3.3.5 above) we prefer to see clear and direct pricing signals to users of the grid that are not muted by time lapse or that become opaque through bundling with other end consumer services. The EA rightly recognises that there are a number of trade-off's to consider but the two main issues that we see are:

- distribution companies are transmission customers but are not participants in the wholesale market while retailers are "the other way around", and
- charges for sunk transmission assets could be viewed as cost recovery by both retailers and distributors, which runs the risk that the B-P charge will become an administrative instrument and its effectiveness is lost.

Either group could have a role to play under a B-P transmission pricing mechanism.

### 2.3.9. Simple SPD – overall assessment

Based on their qualitative assessment the EA is of the view that the simple SPD better promotes the EA's statutory objective than the status quo transmission pricing arrangements and that it addresses key issues identified by submitters. They rightly attach the caveat to their view that the final assessment would be dependent on a full quantitative cost benefit analysis. We agree with this caveat regarding the CBA.

We take a somewhat different view regarding their qualitative assessment and are of the view that the simple SPD proposal has not addressed some of the important issues that were identified from the 2012 proposal and it leaves a number of new design issues to be resolved. We are still of the view that charging beneficiaries of transmission services is the right thing to do but the difficulties that need to be overcome in developing a way to pursue this objective are not trivial. The EA is still trying to find a mechanism to develop a single, simple, low cost charging mechanism to resolve the three different, and difficult, economic problems – as we noted in our advice on the 2012 proposal.[2]

[2] The problems are: sunk cost recovery, investment incentives, and minimising free riding.

## 2.4. Use of GIT

The EA has proposed two charging options that use the simple SPD mechanism and a charge for "reliability investments" that is directly driven from the Grid Investment Test (GIT). The GIT is a business case analysis of new transmission investments that identifies probable beneficiaries for the investment using a cost-benefit analysis.

The two charging options are to:

- first apply the GIT charge to specific assets, (the EA have identified 6 investments that would be subject to a GIT based charge), and then use the simplified SPD mechanism to allocate the remainder of the assets to beneficiaries – i.e. GIT+SPD
- apply the simplified SPD calculation and recover remaining required revenue (if any) from a GIT-based charge for reliability investments – i.e. SPD+GIT

In either case there will also be a residual amount for which no beneficiaries can be identified.

The EA propose that an "area of benefit" would be identified and the full revenue requirement would be recovered from load in that area in proportion to the energy consumed in the previous year.

While the GIT based options could be viewed as an administrative EA allocation methodology, they do have merits – the GIT approach recognises that some reliability investments do not belong in the 'residual' because they have a narrower set of beneficiaries that simply "everyone". The GIT based charge thus warrants further investigation.

As it stands, GIT based allocation mechanism described by the EA is very simplistic, to the point of being crude. The EA suggests GIT-based charges be levied on energy consumed. This is despite the fact that reliability investments are most useful during periods of high demand. This means that the GIT charge could easily lead to some consumers paying charges that are larger than the benefits obtained from the investment.

It is also unclear how the GIT-based charge relates to the SPD calculation of benefits, given that the SPD approach includes a calculation of benefits from avoided non-supply. A GIT+SPD charge could thus double-count benefits to some consumers.

As proposed the GIT charge would not reflect changing market conditions – at least not very well. The costs of reliability investments will be imposed regardless of whether expected benefits materialised. If it transpires that reliability benefits were not realised then a (pseudo) beneficiary-based distribution of costs may not be efficient. An SPD+GIT charge is thus more appealing than GIT+SPD as it should help to minimise the impacts of inaccuracies and other shortcomings in GIT-based charges by limiting the scope of application of the GIT charge.

Whether these are material considerations is, in part, an empirical matter. These should be considered in the context of cost-benefit-analysis of a full transmission pricing proposal.

A GIT-based charge also shifts (some) costs of transmission from obvious non-beneficiaries to a set of possible and probable beneficiaries. This is certainly an improvement to status quo in terms of investment and dynamic efficiency. It will, however, come with costs associated with the fact that it is crude. Whether it is net beneficial then is a matter of trade-offs and needs to be compared against alternative charging approaches or components of a transmission pricing methodology.

## 2.5. Zonal option

The fourth option that the EA offers is a “simple-simple” SPD version where the transmission network assets are divided up into zones that are in effect interconnected to other zones via an “interconnector”. So, instead of the SPD mechanism being applied to all network assets individually it is applied to the interconnector only to calculate the benefits from the interconnector between zones. The transmission assets within a zone are assumed to benefit only load and generation within that zone and the costs would be charged to all load and generation on a yet to be decided basis. The EA emphasise that the purpose of this option is to keep the mechanism simple.

While it may seem that it is indeed a simple option, we see considerable difficulties in the process of agreeing zones, identifying interconnector assets and defining an intra-zone charging mechanism that keeps faith with the beneficiaries approach. As a result, this option likely will result in outcomes that are inconsistent with charging on identified benefits.

## 2.6. The options compared

So what are our overall views about the options?

Here we do not review the EA assessment in their Table 5 but restrict our comparison to the high level financial impacts of the options. We have used the EA modelling results to prepare the following comparison of the transmission charges under each of the options. The EA modelling was based on a demand scenario for 2016/17 that uses four months of 2012 actual data. The projected demand results in a set of changes to the transmission network which, in turn, forms the basis of the SPD modelling.

We have taken the EA results on face value and caution that these are illustrative only and help to highlight the differences between the options proposed by the EA.

Table 4 The B-P options (Interconnection only - all EA 2016/17 scenario)

| | Simple SPD ½ Hour Cap | Simple SPD Daily Cap | GIT + Simple SPD (Gross) | GIT + Simple SPD (Net) | Simple SPD + GIT (Gross) | Simple SPD + GIT (Net) |
|---|---|---|---|---|---|---|
| | **$m** | **$m** | **$m** | **$m** | **$m** | **$m** |
| **Load** | 645 | 645 | 667 | 666 | 680 | 681 |
| **UNI** | 272 | 258 | 446 | 468 | 331 | 370 |
| **LNI** | 159 | 179 | 109 | 135 | 159 | 174 |
| **USI** | 77 | 73 | 52 | 21 | 75 | 43 |
| **LSI** | 137 | 136 | 60 | 42 | 115 | 94 |
| **Generation** | 194 | 194 | 194 | 179* | 192** | 153 *** |
| **UNI** | 17 | 18 | 18 | 0 | 7 | |
| **LNI** | 63 | 64 | 64 | 18 | 26 | |
| **USI** | 45 | 44 | 44 | 76 | 67 | |
| **LSI** | 70 | 69 | 69 | 85 | 92 | |
| **Total** | 839 | 839 | 861 | 844 | 871 | 835 |

Source:

* Includes $46m of disbenefits which have been "removed"

** Includes $20m of disbenefits which have been "removed"

*** This is the residual allocated to generation using EA share of RCPI

## 2.7. Embedded generation and gross/net charging are important

There remains an open question about how beneficiary-based charges should be applied to embedded and distributed generation. The EA does not take a firm position on this issue. There are two apparently conflicting issues:

- charges on gross generation overstate benefits from the grid
- net injection charges could cause generators to embed to avoid transmission charges and this is inefficient.

On the first issue, the intuition behind this is reflected in the EA's consideration of a 'less complex SPD' in Appendix B (p.105) and in reference to Total Service Long Run Incremental costs (TSLRIC) (p.12-13).

In Appendix B the EA considered calculation of beneficiary pays charges via a 'scorched earth' calculation involving removing interconnection assets and costing the construction of local generation required to meet demand. The EA deemed this approach to be problematic because it did not connect charges to changes in benefits from incremental investment. Nonetheless, the exercise is instructive in the sense that if the grid was unavailable, embedded and distributed generation would, in general, still be available to serve local load. In other words, costs of constructing new generation would be offset by the existence of local supply. In this sense local generation is a substitute for grid-based supply.

The TSLRIC view of the world, while deemed impractical and inappropriate as a charging regime under current regulatory settings[3], is also instructive. Under TSLRIC, prices are set to reflect the costs of new 'total service' increments of capacity needed to service demand. Total service means all the attributes or services provided by the network. As discussed by the EA, a TSLRIC-based charge would involve determining the increment in (total service) network costs required to service a customer (or customers). It is abundantly clear that local (embedded or distributed) generation reduces demand and hence reduces costs except to the extent that:

- it injects into the grid
- needs to be supported by some (net) load from the grid
- or imposes costs to quality and reliability of supply across the grid.

Costs imposed by these activities are most closely approximated by net generation and not gross generation. Cost-based charging is not the central issue here (for the discussion of beneficiary based charges) but it is relevant given:

> *In terms of the Authority's decision-making and economic framework, even though a TSLRIC-based charge would be set administratively, it can be considered market-like in that it reflects a charge similar to that which would arise in a workably competitive market, since the price approximates LRMC. This means that it would sit above the beneficiaries-pay charge in the Authority's hierarchy of preferred options for a TPM. (paragraph 5.17)*

On the second issue, the EA says 'It is important to ensure that the charge is designed so that it does not promote inefficient behaviour by parties seeking to avoid charges' (p.51). The EA is not very clear about what 'inefficient behaviour' means.

We submit that in the context of a beneficiary-pays charge, demand response is never inefficient. Only the structure and level of prices are inefficient.

Presumably the EA is concerned that charging on the basis of net injection means embedded generation could benefit from interconnection assets – via higher prices – but face no charges. One example of how this might happen would be if southward flows raise prices in the Upper North Island. Generation in the region would benefit from this, courtesy of interconnection, regardless of whether it was embedded or not. In this scenario, costs of interconnection charged to load (e.g. South Island load) will be higher than they need to be and beneficiary-based charges will not be as efficient as they could be. Generation will be incentivised to embed and the problem could be exacerbated.

3 The EA takes the view that TSLRIC is not feasible because it is based on forward looking costs and would result in prices which are too low to recover Transpower's actual costs.

A specific exception to this is industrial co-generation linked to industrial processes. This kind of generation does not necessarily benefit from higher prices because it relies on the existence of load. As long as load exceeds generation (which it always will if the generation depends on processes fuelled by imported electricity), an extra dollar to the generator is an extra dollar in cost to load. When generation is dependent on load its generation costs will increase at the same time as prices increase revenue. There is therefore no guarantee that rising prices have created any benefits and may have created net costs.

The precise balance of impact or extent of costs is a matter of some detail. It will depend on mix of fuel sources and the balance of generation versus load. These things cannot be observed in wholesale market price movements.

This is not to suggest that load or co-generation do not or cannot benefit from gains from trade thanks to transmission investment. Rather it points to the fact these benefits can only be measured with reference to net injection or off-take – with net off-take indicating benefits from lower prices and net-injection indicating a balance of benefit from higher prices.

The claim could be made that benefits on either side of the coin – higher prices to generation or lower prices to load – offset each other.[4]

This claim only works if generation operates independently of load. If load is the dominant (marginal cost) consideration and generation depends on load as an input, then generation will be curtailed and supply along with it – even as prices increase.

On the other hand, if prices are falling then load might increase and generation increase along with it. Again, the only way to know which way around these effects are working is through observation of net offtake or net-injection.

This is important as changes in transmission charges can be sufficiently large as to offset any gain in consumer surplus from, for example, reduced prices. This is true in general but also true for the 'benefit-based' charges (see Appendix X – technical note).

## 2.8. Matters that remain a concern to us

We commented earlier on the 2012 matters of concern that are still unresolved and that a number of 'yet to be decided on issues' have emerged from this working paper. Regardless of the B-P option selected there remains a list of formidable matters outstanding e.g.:

- quantitative CBA of the full TPM package
- minimising pass through of charges (especially residual charges) from generators to consumers to improve dynamic efficiency gains from TPM
- ensuring the TPM is integrated into the wider regulatory system
- ensuring charges do not inefficiently penalise decisions by load and generation not to rely on interconnection

[4] One could go so far as to argue that the balance of impact is a matter for contracting parties (in practice or de facto where cogeneration is owned by industry).

- striking the right balance across multiple pricing and transmission investment objectives given limited numbers of tools presently available to the EA.

The B-P paper has suggested a number of welcome improvements on the 2012 TPM proposal but given the difficult issues which remain it would be fair to say that we reserve judgement about the extent to which the EA's B-P paper is positive from the point of view of long term benefits to consumers.

# Appendix A Note on benefit calculations

The general value behind the EA's calculation of beneficiary pays charges is that, because a benefit exists, the pricing methodology can charge up to the full extent of the benefit from an incremental transmission investment without reducing overall net benefits to consumers (or producers) from incremental transmission investments.

This works conceptually but the result is not assured by the methods proposed by the EA. This is because the EA does not consider transmission charges in its calculations of consumer surplus.

Consider, for example, that the value to consumers of electricity, in terms of net consumer surplus, is:

$$CS(p,t) = S(p,t) - p.D(p,t) - t.D(p,t)$$

That is, consumer surplus (CS) comprises gross value or surplus to consumers (S) at demand (D) which occurs at wholesale price *p* and given associated transmission charges *t*. We assume here, for simplicity, that transmission charges are a linear function of demand.

The consumer surplus calculation proposed by the EA omits transmission prices and thus measures:

$$CS^{*}(p,t) = S^{*}(p) - p.D(p)$$

Consumer surplus is calculated based on demand which, implicitly, reflects transmission charges but excludes the effect of transmission charges on consumer surplus.

The EA, in effect, proposes calculating benefits of incremental transmission investment by:

$$\frac{dCS^{*}(p)}{dp} = \frac{dS(p)}{dp} - p.\frac{dD(p)}{dp} - D(p)$$

This calculation is used to apportion transmission charges. Transmission charges are, implicitly, held constant and so do not matter for changes in consumer surplus. But transmission charges are not constant in practice. The charges change with changes in wholesale price:

$$\frac{dt}{dp} = \alpha.\frac{dCS^{*}(p)}{dp} = \alpha.\left[\frac{dS(p)}{dp} - p.\frac{dD(p)}{dp} - D(p,)\right]$$

$$dt = \alpha.dS(p) - \alpha.p.dD(p) - \alpha D(p).dp$$

This then affects the benefits to the consumer of the incremental transmission investment (using differentials):

$$dCS(p,t) = (S_p - D(p,t) - p.D_p - t.D_t).dp + (S_t - D(p,t) - p.D_t - t.D_t).dt$$

Given the way consumer surplus is proposed to be calculated, the change in transmission charges (*dt*) can be sufficiently large as to offset any gain in consumer surplus from reduced prices. The reason this result is possible is that the charge is calculated without reference to the initial transmission price. This is also true for changes in producer surplus.

This means that a beneficiary-pays calculation might show a benefit but that a consumer or other grid customer who take steps to avoid an incremental charge, for example, is indeed acting efficiently (in terms of overall efficiency). In order to check whether or not this is the case, we require an understanding of the change in transmission charges and thus the initial level of transmission charges.

The 'initial' level of transmission charges which is relevant is the efficient price for existing (non-incremental) assets – rather than current charges, given that the EA is attempting to improve the efficiency of current charges.

This raises questions about what the efficient price should be for infra-marginal assets. This is likely to be a price approximating a share of TSLRIC-based charges or a share of the scorched earth calculation of the benefits of the grid.