

Information Paper

Allocation of residual loss and constraint excess
post introduction of financial transmission rights

Prepared by the Electricity Authority
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Executive summary

1. This paper outlines the Electricity Authority's (Authority) analysis of the options for allocating residual loss and constraint excess (LCE) once financial transmission rights (FTRs) are introduced.
2. Based on the analysis in this paper, the Authority considers that the preferred approach is to retain and use the current methodology for allocating residual LCE. The Authority recognises this would lead to some change to allocation outcomes following the introduction of FTRs. However, these changes are not viewed as being likely to create any material economic efficiency concerns.
3. Furthermore, the Authority will have other opportunities to consider and revise the allocation methodology if any economic efficiency concerns were to emerge in future.
4. The Authority invites feedback from interested parties on the analysis and conclusion in this paper. Any feedback would be most useful to the Authority if it was provided by 14 August 2012.
5. Feedback should be emailed to submissions@ea.govt.nz with "Allocation of residual loss and constraint excess post introduction of FTRs" in the subject line. Please indicate if any information included is provided on a confidential basis.

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Glossary

Connection rentals	Rentals on connection assets
HVDC rentals	Rentals generated on the high voltage direct current link between Benmore and Haywards
FTR	Financial transmission right – an instrument to mitigate locational price risk
FTR auction proceeds	Payments received from buyers in FTR auctions
FTR payments	Payment to holders of financial transmission rights
FTR Grid	Portion of NI grid that is defined as supporting flows between Haywards and Otahuhu
Interconnection rentals	Rentals generated on interconnection assets
Loss and constraint excess	Total rentals collected by the settlement system – same as the difference between total receipts and payments in spot market
Non-FTR Grid	Portion of grid excluding FTR grid
Rental	The price differential on a transmission circuit multiplied by flow on the circuit in a given period
Residual LCE	FTR auction proceeds + LCE generated on FTR grid - FTR payments
Transformed rentals	Sum of LCE generated on non-FTR grid and Residual LCE

1. Introduction

1.1 Purpose

1.1.1 This paper considers options for allocating transformed rentals¹ once financial transmission rights (FTRs) are introduced. The paper provides a high level assessment of the costs and benefits of the different options and identifies a preferred alternative. While this is not a formal consultation paper, the Authority welcomes any feedback from interested parties industry on the issues discussed in this paper and its conclusion.

1.2 Structure of paper

1.2.1 This paper is structured as follows:

- (a) section 2 describes options for allocating transformed rentals;
- (b) section 3 sets out a high level cost benefit assessment of the options; and
- (c) section 4 concludes with a preferred option.

1.2.2 Given the topic this paper is fairly technical in nature. Readers who are less familiar with some of the terminology in this paper are referred to the glossary at the beginning of this paper.

¹ Comprising the loss and constraint excess not allocated into the FTR account to fund payments to FTR holders (as set out in section 14.73 of the Code), and the residual loss and constraint excess as defined in the Code.

2. Allocation options

2.1 Loss and constraint excess

- 2.1.1 The LCE is the difference between the amount invoiced to wholesale electricity market payers by the clearing manager, and the amount paid by the clearing manager to payees. In economic terms, it can be considered to be a transmission rental.
- 2.1.2 Over the last decade, total LCE has varied between around \$60m and \$210m per annum, with an average of around \$96m per annum.
- 2.1.3 The Electricity Industry Participation Code 2010 (Code) provides for this LCE to be paid to Transpower (or more precisely each grid owner). Furthermore, the Benchmark Agreement (incorporated by reference into the Code) provides that Transpower will allocate LCE via rebates to its transmission customers "in accordance with its prevailing methodology". The Code and Benchmark Agreement are available at <http://www.ea.govt.nz/act-code-regs/code-regs/the-code>.
- 2.1.4 In broad terms, Transpower's current methodology² provides for LCE generated on the differing asset types (connection, interconnection, and high voltage direct current (HVDC) assets) to be rebated to the customers associated with those classes of asset³.
- 2.1.5 When FTRs are introduced, some of the existing LCE pool will be used to fund FTR payments rather than being passed to Transpower for allocation via the rebate mechanism. Furthermore, a new source of funds will be added in the form of the money received from buyers of FTRs in FTR auctions. Consequently, once FTRs are introduced, Transpower will receive:
- (a) LCE associated with the non-FTR portion of the grid (as at present);
 - (b) Residual LCE comprising LCE associated with the FTR portion of the grid plus FTR auction proceeds minus payments to FTR holders.
- 2.1.6 For shorthand, this paper refers to this total pool as transformed rentals.

² See www.transpower.co.nz/f1491,934892/transmission-rentals-2008.pdf

³ Connection rebates are asset/customer specific, and rebates for HVAC and HVDC charges are each calculated on a pro-rata basis.

2.2 Allocation options for transformed rentals

2.2.1 This paper considers three options for allocating transformed rentals once FTRs are introduced:

- (a) **Option 1** would retain the current *methodology* used for allocating LCE. Notwithstanding retention of the *methodology*, this section explains why there would be an effect on allocation *outcomes* once the FTR regime comes into operation;
- (b) **Options 2 and 3** would effectively divide transformed rentals into two categories – a portion arising on that part of the grid associated with the FTR regime (essentially the arcs linking Bemore and Otahuhu), and the balance arising on the remaining ‘non-FTR’ grid. Both options would preserve current allocation outcomes in respect of LCE arising on the non-FTR grid, but would treat the balance of LCE (called Residual LCE in the Code) in different ways:
 - (i) Option 2 would split Residual LCE into HVDC and interconnection components based on the shares of rentals generated on the respective asset types in the settlement period;
 - (ii) Option 3 would provide for fixed monthly rebates to HVDC customers (based on expected average levels), with the balance of Residual LCE being paid as rebates to interconnection customers.

2.2.2 A number of other options have been previously considered by the Authority and the Locational Price Risk Technical Group. Some of these were variants of Options 2 or 3, and others were completely different (for example using LCE to reduce the Authority levy). These other options are not explored further in this paper as earlier analysis and feedback from the Locational Price Risk Technical Group indicates they are less likely to promote the statutory objective than Options 1-3.

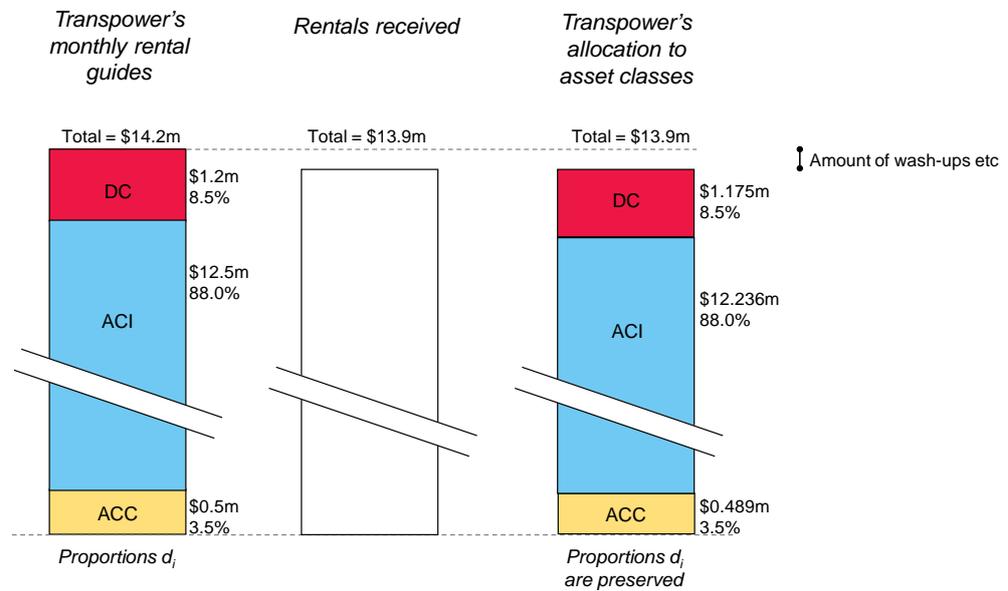
2.3 Option 1 – Continue current methodology

2.3.1 As noted earlier, the current allocation methodology (i.e. pre-FTRs) provides for LCE to be divided into three categories associated with AC connection assets (ACC), AC interconnection assets (ACI), and HVDC assets. Transpower does this by classifying each transmission arc into one of those three asset classes. Each arc flow is then multiplied by the price difference across the arc, and the amounts are summed for each of the three asset classes to give monthly “rental guides”.

2.3.2 These guides determine the proportions in which the LCE is allocated to the three asset classes. The LCE can be greater or less than the sum of the monthly rental

guides due to factors such as wash ups. Once LCE received is allocated to the three asset classes, it is rebated to customers, broadly speaking, in proportion to customers' transmission charges in that asset class. This is illustrated in Figure 1.

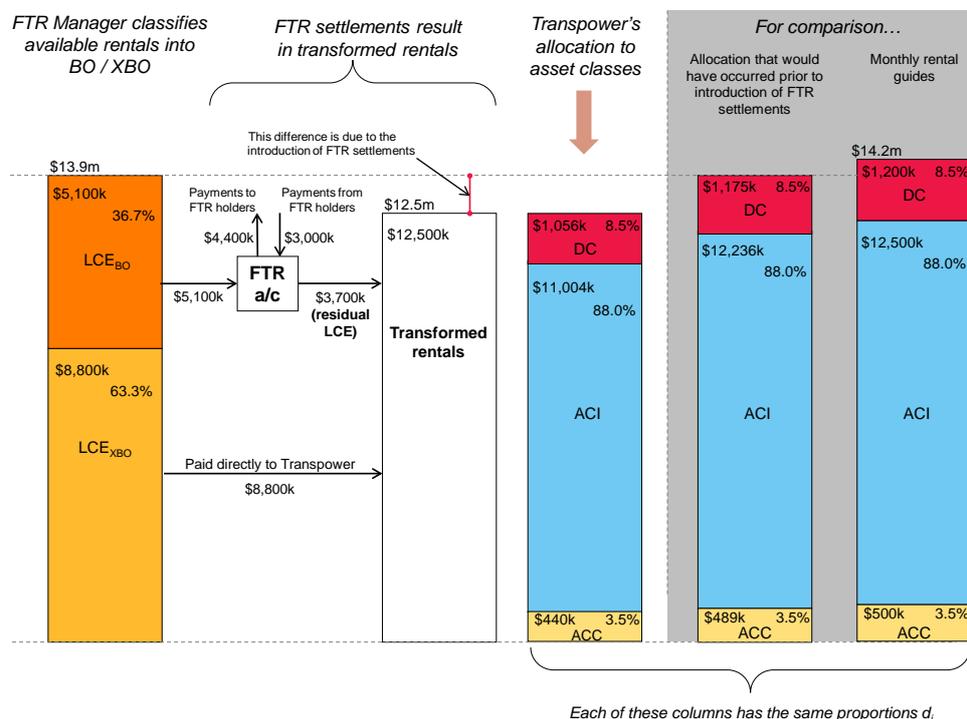
Figure 1: Allocation of LCE to asset classes using monthly rental guides



2.3.3 As noted in section 2.1.5, when FTRs are introduced the LCE pool will change and Transpower will instead receive transformed rentals.

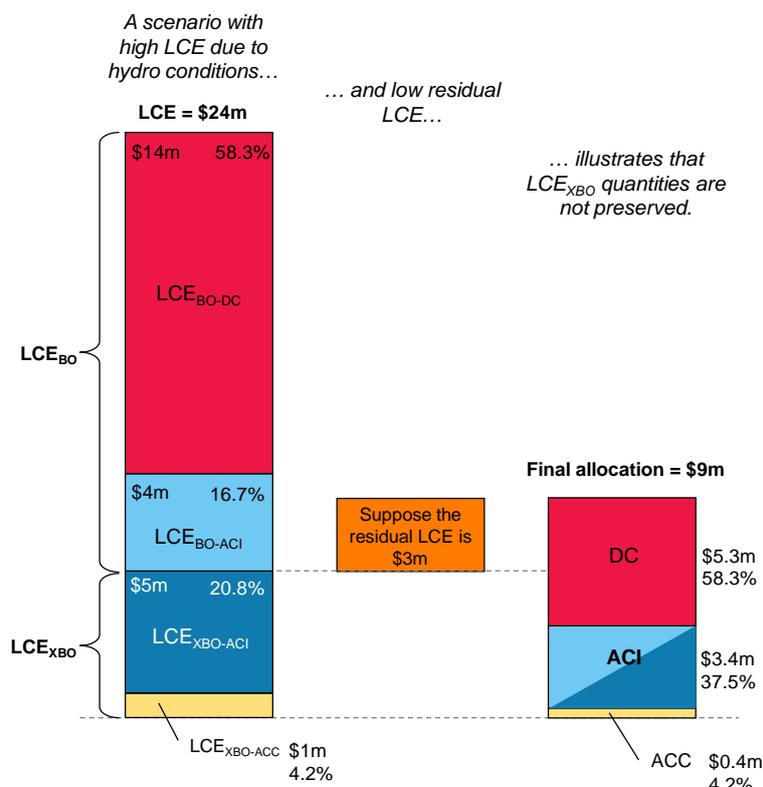
2.3.4 As matters stand, Transpower will allocate the transformed rentals in accordance with the same methodology it currently uses for allocating LCE. Figure 2 provides an illustrative example of the resulting financial flows once FTRs are introduced.

Figure 2: Existing allocation methodology after introduction of FTRs



- 2.3.5 One of the features of applying the existing allocation methodology after the introduction of FTR settlements is that it would not preserve the allocation of LCE to each asset class (HVDC, ACI or ACC).
- 2.3.6 This is because currently both LCE and rebate amounts reflect spot prices in the settlement period. However, once FTRs are introduced, part of the rebate stream will be dissociated from short term spot prices, and instead reflect the outcome of the FTR auction (which is expected to reflect average rather than current 'spot' conditions).
- 2.3.7 This can be illustrated more clearly by using a more extreme example where the 'spot' monthly LCE generated on the FTR grid between Benmore and Otahuhu (LCE_{BO}) happens to be much larger than the 'expected average' residual LCE. This might occur if (for example) monthly LCE_{BO} increased relative to the expected average position because of short term hydrological conditions. It is important to emphasise that this example is purely illustrative. In practice, the direction and magnitude of the size differential will change from settlement period to settlement period. It should also be kept in mind that it is possible for residual LCE to exceed LCE if FTR auction payments exceed LCE and are not needed for FTR settlement.

Figure 3: Illustrative example after FTRs introduced (status quo methodology)



2.3.8

The key observations from the illustrative example are:

- (a) The \$0.4m rebate to connection customers is smaller than the \$1m LCE generated on connection assets (shown as $LCE_{XBO-ACC}$);
- (b) the \$3.4m rebate to AC interconnection customers is smaller than \$9m LCE generated on interconnection assets (shown as $LCE_{BO-ACI} + LCE_{XBO-ACI}$). In fact, it is smaller even than the \$5m LCE on the non-Benmore-Otahuhu interconnection assets (shown as $LCE_{XBO-ACI}$); and
- (c) the \$5.3m rebate to HVDC customers is smaller than the \$14m LCE generated on the HVDC link (shown as LCE_{BO-DC}).

2.3.9

While the example is purely illustrative and the magnitude and direction of differences will change from month to month, the general point is that the rebates attributable to each asset type will not reflect LCE generated on those asset

classes in a settlement period (other than by pure chance). That said, over the long run these differences are expected to broadly offset each other⁴.

- 2.3.10 It should also be recognised that the short term differences in respect of the FTR portion of the grid are an inevitable and intended consequence, because the associated LCE will be used to fund FTRs, and therefore can't be directly available to fund rebates⁵.
- 2.3.11 However, the lack of reflection by the rebates of the actual rentals extends beyond the portion of LCE/rentals falling directly within the FTR regime. Under this option, for example, the allocation of LCE generated on connection assets would be affected by the interaction of FTRs and the current allocation methodology.
- 2.3.12 The implications for economic efficiency (positive and negative) of this option are discussed in Chapter 3.

2.4 Option 2 – Split LCE bucket

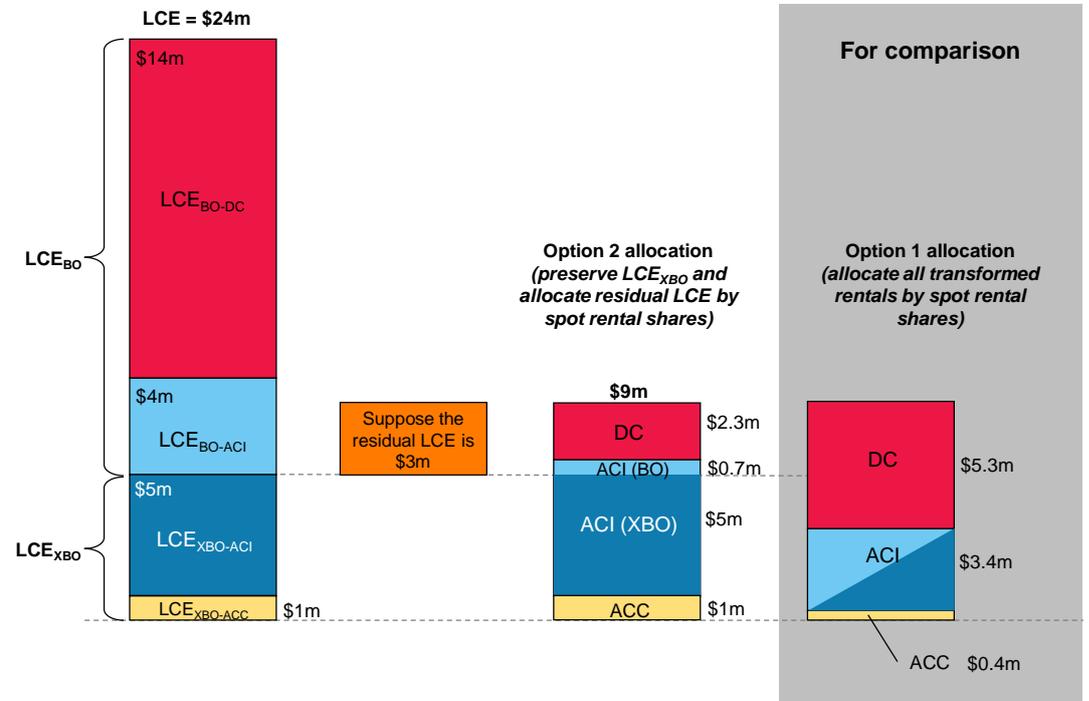
- 2.4.1 Under the previous option, the allocation of LCE generated on both the FTR and non-FTR portions of the grid would change once FTRs are introduced. In principle, it would be possible to keep the two categories (i.e. residual LCE and LCE_{XBO}) separate and allocate the latter component in the same manner as at present.
- 2.4.2 This would require:
 - (a) the FTR Manager to have information about the classification of transmission arcs into asset classes (currently it does not formally have access to that information); and
 - (b) Transpower to change its allocation methodology so that it takes the FTR Manager's allocations to each asset class as given.
- 2.4.3 It would also require a decision about how to allocate residual LCE between asset classes (i.e. the split between HVDC and AC interconnection assets). There is no unambiguously preferred way to do this. The simplest approach would be to divide these based on the spot LCE proportions in the relevant

⁴ This assumes (among other things) that FTR payments and auction revenues are broadly equivalent over time.

⁵ And as noted earlier, the auction process will provide a new and less volatile revenue source to contribute to rebate funding.

settlement period. An example of how this would apply is shown in Figure 4 using the same data as the previous example.

Figure 4: Option 2 – example of allocation outcome



2.4.4

For the illustrative example, the two right hand columns show the outcomes under Option 2 and 1 respectively, and the left hand column shows the status quo prior to the introduction of FTRs. The key points to note are:

- rebates arising on the non-FTR grid are unchanged by the introduction of FTRs under Option 2 (but not Option 1):
 - connection rebates are unchanged as $ACC = LCE_{XBO-ACC}$;
 - non-FTR grid portion of interconnection rebates are unchanged as $ACI(XBO) = LCE_{XBO-ACI}$; and
- rebates associated with the FTR grid relate solely to residual LCE rather than LCE per se, with the split between HVDC and ACI(BO) determined by spot market conditions; and
- although the interconnection rebate would be calculated as two separate amounts for the FTR and non-FTR portions of the grid (i.e. \$5.0m relating to XBO and \$0.7m relating to BO), the combined amount of \$5.7m would be pooled for the purpose of distributing rebates among interconnection customers.

2.4.5

A further important point to note about Option 2 is that distributing the residual LCE based on spot market conditions would tighten the potential linkage (relative

to Option 1) between FTR bidding behaviour and receipt of residual LCE. As discussed later, if there was a sufficiently close linkage and some other factors applied, this could undermine bidders' confidence in the FTR auction process. For this reason, Option 3 has been developed to sever such a linkage if this was regarded as a major concern.

2.5 Option 3: Fixed amount for HVDC rebates

- 2.5.1 This is the same as Option 2, except that the allocation of residual LCE between HVDC and ACI(XBO) rebates would not be based on spot LCE patterns in each month. Instead, the HVDC component would be a fixed dollar amount, leaving the variable balance to be allocated to ACI(XBO) rebates.
- 2.5.2 The fixed dollar amount would be set to reflect the average of expected HVDC rebates (absent any policy change) over the medium term. For indicative purposes, this has been estimated at \$15m per year (\$1.25m/month), but this figure would need to be firmed up through more detailed analysis if the option were to proceed further.
- 2.5.3 Analysis to date indicates that the residual LCE stream would be sufficient to cover a fixed \$1.25m rebate in most months. However, a shortfall could sometimes occur (e.g. during a HVDC outage when LCE arising will be lower), and this raises the issue of whether any shortfall is carried as a claim (possibly with interest) into the subsequent month etc. If a mechanism to fix the amount was adopted, recipients of HVDC rebates could have a periodic cashflow reduction, but would receive a certain sum over time.

3. Assessment of options

3.1.1 This section discusses the expected impact of the different options on economic efficiency, and the level of direct costs that would arise to implement each option. It then uses this information to identify a preferred option for moving forward.

3.2 Economic efficiency effects

3.2.1 The allocation of LCE could affect economic efficiency in three broad ways:

- (a) **bidding incentives in FTR auctions** - concern has been raised in the past about the potential for LCE rebates to influence FTR bidding incentives. To the extent that any distortion did arise, this could affect participation in FTR auctions, and therefore have flow on impacts on competition in the retail and hedge markets;
- (b) **management of intra-island locational price risk** - at present the allocation of AC interconnection rentals to parties that pay AC interconnection charges provides some (albeit very imperfect) hedging for purchasers against intra-island locational price risk. The degree of hedging could be affected by the rental allocation following the introduction of FTRs. This in turn could have a flow-on impact to competition in the retail and hedge markets.
- (c) **dynamic efficiency** - the interaction of a rental allocation methodology (existing or new) and the introduction of FTRs may give rise to a value transfer between parties or classes or parties, relative to historic arrangements. While the Authority's statutory objective is not concerned with value transfers per se, if they were sufficiently large and not accompanied by a corresponding efficiency rationale, such effects could increase uncertainty, and make investments riskier.

3.2.2 The effect of the three options on economic efficiency is discussed further below.

3.3 Effect on FTR bidding incentives

3.3.1 The concern in this context is whether the allocation methodology will undermine the confidence of potential bidders in FTR auctions and/or distort auction outcomes. The risk would arise if a party:

- (a) has the ability to influence the price of FTRs in the auction process (noting that any change will flow through to the residual LCE);
- (b) receives a sizeable portion of any increase in residual LCE through the rental allocation process;

- (c) can retain that increased allocation without it being competed away; and
 - (d) finds that action profitable.
- 3.3.2 The portion of residual LCE paid as rebates to interconnection customers (grid connected industrial users and lines companies) is unlikely to cause concern because one or more of conditions (a) – (c) would not be satisfied. However, the position is less clear cut with the HVDC component of residual LCE. Under present arrangements, this would be paid to parties with South Island generation, who could reliably estimate their shares of auction proceeds and expect to retain that value.
- 3.3.3 For this reason, further analysis has been carried out to assess the degree to which (b) above would hold under options 1 – 3. This analysis considered:
- (a) how much of any increase in residual LCE achieved through bidding behaviour would flow back as HVDC rebates to South Island generators collectively. To do this, the analysis considered rebate patterns over a range of simulated system conditions; and
 - (b) how much each South Island generator would capture of any collective increase in rebates. This is determined by their share of observed half hour any time maximum injection (HAMI). The largest share is currently 70% for Meridian.
- 3.3.4 For a generator with 70 percent of HAMI, the proportion of any increase in residual LCE that would be retained by the generator has been estimated for the two years beginning 2013. A sensitivity case of four years has also been considered.
- 3.3.5 It is important to note that the resulting estimates are sensitive to assumptions. Nonetheless, the estimates provide guidance as to the relative magnitudes of the retained proportion under different options.

Table 1: Retained proportions of any increase in residual LCE

	Retained ratio (2 years)	Retained ratio (4 years)
Option 1	10%	9%
Option 2	25%	22%
Option 3	0%	0%

- 3.3.6 This analysis suggests that Option 3 is the least likely to give rise to concerns about incentives in FTR auctions, followed by Option 1 and then Option 2. However, even under these latter options the degree of concern is unlikely to be especially high as the ratios remain relatively low (particularly for Option 1).

3.3.7 Furthermore, even if these ratios had been much higher, this would not necessarily lead to undesirable incentives. As discussed in paragraph 3.3.1, to distort auction outcomes other conditions would also need to apply. In particular, it appears somewhat unlikely that buyers would be prepared to pay a significant 'premium' for an FTR above that implied by expected locational price differentials. It is more likely that they would forego the FTR than lock-in an apparent price impost. For this reason, it is doubtful that conditions (a) and (d) in paragraph 3.3.1 would hold.

3.3.8 This means that the relative ranking of options against this efficiency criteria should be treated as a broad guide rather than being highly definitive.

3.4 Effect on intra-island locational price risk

3.4.1 The introduction of FTRs will improve parties' ability to manage *inter-island* locational price risk because rights to LCE between Benmore and Otahuhu will become available through the FTR auction process. Parties that hold a FTR will have a risk management instrument that can mitigate the effect of price differences between Benmore and Otahuhu.

3.4.2 However, FTRs (at least in their initial form) are not expected to have any material mitigating effect on intra-island locational price risk⁶. Instead, parties exposed to this risk will need to rely on existing mechanisms. One of these is access to the LCE generated on connection assets and those interconnection assets outside the FTR regime.

3.4.3 At present, LCE generated on these assets is transferred to connection and interconnection customers via the rebate process. For connection customers, this process is understood to provide a degree of locational hedging⁷ between their individual offtake point and the point of connection with the main grid. That said, it is important to note that the degree of locational price risk arising on connection assets is relatively modest compared to that arising on interconnection assets as a whole. The LCE attributed to these assets is also a relatively small share of the total pool (around 6 percent historically).

3.4.4 The degree of hedging provided to interconnection customers is more imperfect because the LCE generated on this portion of the grid is treated as one sum, and is currently rebated to interconnection customers based on their share of overall interconnection charges.

⁶ The terms *inter-island* and *intra-island* are commonly used in the industry, but are not strictly defined. Furthermore, there may be some cases where the *inter-island* FTR will be useful to manage *intra-island* risk, for example the risk of price separation between Haywards and Otahuhu.

⁷ This hedging is not complete because there can be fixed losses associated with transformers.

3.4.5 In practice, this means that geographically diverse retailers⁸ receive a reasonable (though imperfect) hedging service against short term locational price risk. Direct connect industrial customers and less geographically diverse retailers also receive some degree of hedging against intra-island risk, but this is even more imperfect because their risks are more locationally specific, whereas the rebate reflects the 'blend' of rentals across all interconnection assets.

Effect of Option 1 on intra-island locational price risk

3.4.6 Following the introduction of FTRs, Option 1 is expected to dilute the hedging properties of the connection and interconnection rebates⁹. This effect would arise because the size of rebates associated with the non-FTR portion of the grid to connection and interconnection customers would no longer be proportional to the LCE generated on those respective assets each month. Instead, it would be affected by the relative size of the residual LCE stream relative to LCE_{BO} as discussed in section 2.3.

3.4.7 The extent of change will vary from month to month, reflecting the size of the differential between the residual LCE stream and LCE_{BO} in each settlement period. An analysis of historic annual data was undertaken to provide an indication of the likely magnitude of possible variability (noting that the long term *average* outcome is expected to be the same).

3.4.8 This analysis suggests that the annual difference¹⁰ would be within +/- 30% for around 67% of the time for interconnection rebates arising on the non-FTR portion of the grid. The difference for connection rebates is expected to show a similar pattern of variability.

3.4.9 In making these comparisons, it is important to note a number of qualifications:

- (a) the calculations involve a range of estimates and assumptions and should therefore be treated as being indicative in nature;
- (b) the impact of Option 1 on individual parties will be influenced by factors outside of this analysis. For example, if a party were to receive a lower/higher rebate associated with connection and (non-FTR grid)

⁸ Although rebates are paid by Transpower to lines companies as interconnection customers, a majority of lines companies pass these rebates to their respective customers (i.e. retailers and any other network customers).

⁹ It is important to stress that all of this discussion is confined to the portion of interconnection LCE/rebates associated with the non-FTR grid, i.e. interconnection assets other than between Benmore and Otahuhu. The effect on LCE/rebates associated with the FTR grid (between Benmore and Otahuhu) is intended to change as a consequence of the FTR regime, and this effect will be common across options 1-3.

¹⁰ That is, the difference in percentage terms in annual rebates made under current arrangements, and those which would apply under Option1 once FTRs are introduced.

interconnection assets, this effect may be partially counteracted by the offsetting increase/reduction in rebates associated with residual LCE; and

- (c) the average difference over time is expected to be nil. This means that the longer term hedging impact should not be significant (assuming parties positions do not change markedly over time).

3.4.10 Finally, it is important to note that the intra-island hedging properties of connection and especially interconnection rebates are far from perfect at present. This makes it difficult to assess the practical impact of Option 1 relative to the current position. Based on current information, it appears unlikely that it would have a marked effect on parties' ability to manage intra island locational price risk.

Effect of Options 2 and 3 on intra-island locational price risk

3.4.11 As discussed in section 2.4, Options 2 and 3 would in effect create two pools of LCE, one associated with the FTR portion of the grid and the other associated with the balance of the grid. This means that the existing hedging properties of LCE associated with connection assets and those interconnection assets outside the FTR regime would be preserved.

3.4.12 Again, however, it is important to emphasise that the degree of hedging provided by current arrangements is far from perfect. As a result, the difference between Option 1 and these alternatives is not expected to be especially significant.

3.5 Effect on dynamic efficiency

3.5.1 As noted in section 3.2, changes that affect the rental allocation could result in value transfers between parties or classes of parties relative to historic arrangements. While the Authority's statutory objective is not concerned with value transfers per se, if a value transfer were not accompanied by a corresponding efficiency rationale, it could increase uncertainty. If this occurred and was of sufficient materiality, this could in turn undermine dynamic efficiency by weakening the incentive for efficient investment decisions.

Effect of Option 1 on dynamic efficiency

3.5.2 The first step in considering potential dynamic efficiency effects is to ask whether use of the existing allocation methodology once FTRs are introduced will lead to any value transfer relative to current arrangements. Analysis indicates that value transfers would be expected in two contexts:

- (a) **between FTR buyers and transmission customers** - differences are likely to arise between the FTR auction proceeds (a pre-estimate based on

average expected conditions) and FTR payments (reflecting spot conditions in each period). This would lead to value transfers between FTR buyers and transmission customers (as collective recipients of rebates); and

- (b) **among transmission customers** - differences between FTR auction proceeds and FTR payments will have a flow-on effect to the allocation of rebates among transmission customers. In particular, as discussed in section 2.3, the size of rebates to connection and interconnection customers would no longer be proportional to the LCE generated on those respective assets each month. Instead, it will be affected by the relativity between FTR auction proceeds and payments.

- 3.5.3 In respect of (a), this is a necessary and consequential effect of introducing the FTR auction process, which is being pursued for clear efficiency reasons (such as facilitating retail competition). Furthermore, while short term value transfers will occur, there is no reason to expect aggregate FTR payments to diverge from aggregate auction receipts over time. This means there would be no ex ante value transfer or inherent bias in either direction. Accordingly, there are no obvious grounds to be concerned about this issue from a dynamic efficiency perspective.
- 3.5.4 Turning to issue (b), this effect is not directly associated with pursuing a specific efficiency goal. Rather it arises as a secondary consequence of introducing FTRs, and it would in principle be possible to avoid the effect through a modified allocation methodology.
- 3.5.5 In terms of size, the indicative analysis referred to in paragraph 3.4.8 suggests that the annual outcomes¹¹ under Option 1 would be within +/- 30% of those under current arrangements for around 67% of the time for interconnection rebates arising on the non-FTR portion of the grid and for connection rebates. However, this variability is not expected to exhibit a bias in any particular direction¹².
- 3.5.6 Accordingly, there is no reason to expect an ex ante value transfer among transmission customers. This should reduce the likelihood of any adverse effect on dynamic efficiency.

¹¹ That is, the difference in percentage terms in annual rebates made under current arrangements, and those which would apply under Option 1 once FTRs are introduced.

¹² Based on broad assumptions about the relative size and variability of different components of LCE and auction payments.

Effect of Option 2 on dynamic efficiency

- 3.5.7 Option 2 would raise the same value transfer issue between FTR buyers and transmission customers as Option 1. However, as noted earlier, this is not expected to give rise to any dynamic efficiency concern.
- 3.5.8 In respect of the potential for value transfers among transmission customers, no effect is expected to arise because LCE generated on connection assets and those interconnection assets outside the FTR regime would be allocated as rebates on the same basis as at present.
- 3.5.9 In short, this option is not expected to give rise to any dynamic efficiency concerns.

Effect of Option 3 on dynamic efficiency

- 3.5.10 Like options 1 and 2, Option 3 would not raise any concerns relating to value transfers between FTR buyers and transmission customers.
- 3.5.11 In respect of the potential for value transfers among transmission customers, this would depend upon the process used to set the level of HVDC rebate. More importantly, even with an objectively robust process, there would be potential for differing perceptions about the outcome from different parties because the estimation process would necessarily involve a number of assumptions and judgements. For this reason, this option has more potential to lead to a dynamic efficiency effect than Option 2, but should be similar to or lower than Option 1.

3.6 Ranking of options on efficiency grounds

- 3.6.1 Based on the analysis set out above, the following observations can be made:
- (a) **Individual efficiency criteria** - there are no clearly significant differences between options when considering each single efficiency criteria. For example, Option 3 is the least likely to influence incentives in the FTR auction process in theory, but the magnitude of any practical gain compared to Option 1 is unclear. Similarly, Option 2 appears least likely to have any effect on dynamic efficiency, but the difference compared to the alternatives is not clear; and
 - (b) **Overall criteria** - even if the tentative individual criteria rankings were more definitive, no single option would emerge as superior across all efficiency criteria. For example, Option 3 may have the lowest risk for FTR auction incentives, but is not the lowest risk in terms of dynamic efficiency effects.
- 3.6.2 These factors suggest that no option clearly dominates based on economic efficiency criteria. This implies that any move away from Option 1 (the default

approach because it requires no change) would need to be justified on precautionary grounds. Accordingly, it is important to consider the implementation and operating costs of the different options, and their relative risk profiles, to see whether these factors lead to a clearer ranking.

3.7 Implementation and operating costs

- 3.7.1 The costs of changing the allocation methodology fall into two broad categories:
- (a) initial implementation costs for the Authority and participants; and
 - (b) any change in ongoing operational costs for the Authority and participants.
- 3.7.2 For the Authority, item (a) would involve liaison with Transpower to design a detailed proposal, preparing a proposed Code change (with legal review) to implement this proposal, drafting a consultation paper, and considering submissions. Participants would also incur costs in reviewing the proposal and responding with submissions. Lastly, there would be the cost of software changes assuming the proposal actually went ahead.
- 3.7.3 For Option 2, these costs are estimated at approximately \$575k in the base case. For Option 3, the costs are expected to be higher because the proposed change would require more analysis to refine its precise form. In particular, some effort would be required to determine the level of fixed rebate associated with HVDC assets. This option is also expected to generate closer scrutiny from participants, meaning that their costs would be higher in the submission process. The base case for Option 3 assumes that costs would be \$825k. A sensitivity case for each option with a 50% increase in costs has also been considered.
- 3.7.4 If Option 2 or 3 were implemented, it is not expected that there would be any change in ongoing costs for the Authority or participants relative to Option 1, because the process for calculating and distributing rebates is largely automated.
- 3.7.5 Further information on the assumed breakdown of costs for each option is set out in Table 2.

Table 2: Implementation cost assumptions¹³

Base case (\$k)	Option 1	Option 2	Option 3
Authority costs for Code change proposal	0	50	200
Participant costs for Code change proposal	0	25	125
Implementation cost (software changes etc)	0	500	500
Total	0	575	825
Higher cost scenario (\$k)			
	Option 1	Option 2	Option 3
Authority costs for Code change proposal	0	75	300
Participant costs for Code change proposal	0	38	188
Implementation cost (software changes etc)	0	750	750
Total	0	862.5	1237.5

3.7.6 Any change to the allocation methodology would only come into effect once FTRs were introduced. This is currently expected to be May 2013 or later. Furthermore, the Authority is undertaking a full review of the current transmission pricing methodology (TPM), and this will necessarily also include any flow on implications for the allocation of transformed rentals. The intention is to complete the TPM review in time for any changes to take effect from April 2015 pricing year.

3.7.7 This implies that the cost of any change to the allocation methodology would need to be recovered over a period of 1.75 years¹⁴. This timeframe has been used to calculate the annualised expected benefit that would be required to recover the assumed implementation costs for Options 2 and 3. The results of this analysis are summarised in Table 3.

Table 3: Annualised expected benefits to breakeven (\$k/year rounded)

Annualised benefit required (\$k)			
Base case costs	Option 1	Option 2	Option 3
TPM review in place 2015	0	300	430
Higher cost scenario			
TPM review in place 2015	0	450	650

¹³ Figures are rounded.

¹⁴ That is, the period between July 2013 and April 2015.

3.8 Level of risk with Option 1

- 3.8.1 As noted above, any decision to move away from Option 1 (the default) would need to be justified on precautionary grounds, based on a view that it is better to certainly incur some level of implementation cost for Option 2 or 3, than to bear potential efficiency risks associated with Option 1.
- 3.8.2 The risks entailed with Option 1 are summarised in Table 4, along with a description of possible mitigants.

Table 4: Assessment of risks for Option 1

Key risks	Mitigation factors
FTR auction incentives are distorted in practice	Authority will be monitoring performance of FTR market – could take action in future if required (including adopting a different allocation option).
Dynamic efficiency is undermined	If such an effect became apparent, Authority could address in context of the wider transmission pricing methodology review, scheduled for completion by April 2015 pricing year.
Management of intra-island locational risk is impaired relative to status quo	The Authority is working on options to address intra-island locational risk. These options are expected to provide better tools for managing intra-island risk than the status quo. The current timetable is for intra-island instruments to be available within two years of FTRs coming into place.

- 3.8.3 In summary, although Option 1 carries some risks, they do not appear to be particularly significant based on available information. More importantly, even if a risk were to emerge in practice, it would be possible to address it at a future point because the decision about allocation of transformed rentals is not a ‘one shot’ process. Indeed, by necessity, this issue will come up for re-evaluation in the context of the TPM review.

4. Conclusion

4.1.1 In summary, the analysis indicates that:

- (a) **pure efficiency criteria** - no option clearly dominates based on economic efficiency criteria. Accordingly, any move away from Option 1 (the default) would need to be justified on precautionary grounds, based on a view that it is better to incur incremental implementation costs for Option 2 or 3, than to bear efficiency risks associated with Option 1;
- (b) **implementation costs** – Option 2 is expected to cost around \$575k to implement, and Option 3 is expected to cost around \$825k. To justify incurring these costs would require expected annualised efficiency benefits of \$300k and \$430k respectively relative to Option 1 (or higher sums in the sensitivity case);
- (c) **risk profile** – the risk profile of Option 1 does not appear to be appreciably higher than for Option 2 or 3, especially given the range of other mechanisms available to address adverse efficiency impacts with Option 1, should any emerge. This makes it difficult to justify incurring certain implementation costs in order to avoid uncertain efficiency gains. This is especially true of Option 3 given its relatively higher implementation costs.

4.1.2 A summary of the options against the assessment criteria, ease of implementation and cost is provided in Table 5.

Table 5 Ranking of options against assessment criteria

Assessment criteria	Option 1	Option 2	Option 3
Reduce incentives to influence FTR bidding	✓✓	✓	✓✓✓
Preserve intra-island hedging	✓	✓✓	✓✓
Dynamic efficiency	✓✓	✓✓✓	✓
Ease of implementation	✓✓✓	✓✓	✓
Cost	\$0	\$525,000	\$825,000

Preferred option

4.1.3 In light of these factors, the Authority proposes to:

- (a) not make any change to the current allocation methodology for transformed rentals at the time the FTR regime becomes operational;
- (b) closely monitor outcomes from the FTR regime once it goes live to identify any concerns with parties incentives in FTR auctions; and
- (c) continue to progress options to strengthen parties' ability to manage intra-island locational price risk.

Industry feedback

- 4.1.4 The Authority invites feedback from interested parties on the analysis and conclusion in this paper. Any feedback would be most useful to the Authority if it was available by 14 August 2012.
- 4.1.5 Feedback should be emailed to submissions@ea.govt.nz with "Allocation of residual loss and constraint excess post introduction of FTRs" in the subject line. Please indicate if any information included is provided on a confidential basis.