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Avoided Cost of Transmission (ACOT) payments for Distributed Generation

FINAL REPORT

31 JANUARY 2014

Prepared For:

Independent Electricity Generators Association

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1. EXECUTIVE SUMMARY

This report has been prepared by Andrew Shelley Economic Consulting Ltd in response to the Electricity Authority's Working Paper *Transmission Pricing Methodology: Avoided cost of transmission payments (ACOT) for distributed generation*, 19 November 2013 ("the Working Paper"). The report was commissioned by the Independent Electricity Generators' Association.

The efficiency analysis in the Working Paper is inadequate, focussing solely on the productive efficiency losses that *might* arise *if* ACOT payments are used to subsidise DG that is less productively efficient than grid-connected generation. No evidence is presented that DG is less productively efficient than grid-connected generation. Furthermore, a much more important source of efficiency is dynamic efficiency (section 3.1), which is consistent with the long-term benefit of consumers (section 3.2).

The Authority seems to have a concern that ACOT reflects avoided transmission charges rather than avoided transmission costs. However, **in *any* market where price exceeds variable accounting cost it will always be the case that a reduction in demand results in a reduction in revenue for the supplier that *exceeds* variable accounting costs.** The Authority should not be surprised, therefore, that the reduction in transmission charges that occurs with a reduction in demand is greater than any underlying reduction in (short run variable) transmission costs (section 4.1).

If the Authority has concerns about the structure of economic regulation for Transpower (i.e. the revenue cap that results in charges being reallocated amongst consumers), then the Commerce Commission's current consultation process concerning Transpower's 2015-2020 price-quality path is the appropriate place to address those concerns (section 4.2).

The price signals from losses and constraints are insufficient to provide a signal for embedded generation, being swamped by other uncertainties that are faced by investors. They also do not provide a sufficient locational signal for grid-connected generation, and nor are they sufficient to fund transmission expansion. The only locational signal that could be provided is via ACOT, and Transpower's interconnection charge is currently set so that it has only a minimal locational component (section 4.4).

The Authority's suggestion that perhaps ACOT should not be paid to older DG is a significant concern. The same principle could be equally well applied to the economic rents that older grid-connected generation earns in the wholesale electricity market. In addition, the regulatory confiscation of these payments would harm long-term investment incentives, and therefore also harm dynamic efficiency and would not be furthering the long term benefit of consumers (section 4.5).

The transmission capital expenditure process relies on forecasts of net demand, and DG projects may only be modelled to the extent that they rely on transmission to proceed (section 5.3). If DG is not being reflected in transmission investment then the Authority should investigate the cause of that failure, whether that is the production of demand forecasts or the transmission investment approval process itself. Multiple DG units provide a combined reliability that is very high, and is sufficient to avoid the need for some transmission capacity at peak (section 5.4). As such DG, should displace transmission investment.

We present a model that calculates the dynamic efficiency benefits of DG, particularly insofar as it reduces the need for future transmission investment (section 5.5). Given a simple model, low levels of DG penetration may result in net benefits from avoided transmission investment of between $3.94/ICP and $7.58/ICP, whereas high levels of DG penetration may result in net benefits of between $15.50/ICP and $29.82/ICP. To the extent that ACOT prevents market failure by enabling DG to internalise the benefits of reduced future transmission investment and reducing the relative risk of DG cash flows, at high levels of DG penetration the benefits induced by ACOT exceed the $10.29 per household cost calculated by the Authority. This suggests that **if the Authority's focus is on long term benefits to consumers, it should be seeking to reduce the barriers to increased DG penetration rather than reducing or removing ACOT payments**.

The Working Paper's conclusion that "losses and constraints are … reflected in wholesale market prices so there would appear to be no substantive case for additional compensation for DG" is only partially correct. The benefits of a reduction in loss and constraint rentals are encapsulated in wholesale market prices for small scale DG, but the reduction in losses and constraints that occur as a result of larger scale DG will not be entirely compensated, and at the margin this could lead to DG being under-provided (i.e. it would be a source of market failure). The same is true of large grid-connected generation and transmission, and is a well-known and well-understood phenomenon (section 7.2).

The Working Paper claims that retail markets for electricity are considered to be a national market. This significantly mis-states the Commerce Commission's conclusion, which generally supports the view that retail markets are regional, at least for domestic consumers. In general, regional retail markets are created by the presence of transmission constraints, a point that is reasonably evident from the Authority's own HHI analysis. **DG has an important role to play in improving retail competition in regional markets** (section 7.3).

We agree with the Working Paper's general conclusion that the ETS and other mechanisms exist to produce a price reflective of the externality resulting from greenhouse emissions, and there is no obvious compelling reason to favour DG over grid-connected generation for environmental benefits (section 7.4).

Important functions of ACOT that have been omitted from the Working Paper are (i) the price signal that it provides for reliability at peak (section 8.1), the role of ACOT-funded price-taking DG in the smoothing of prices during peak periods (section 8.2), and its role in smoothing the relative volatility of cash flows from DG investments (section 8.3). The success of the electricity futures and options on the ASX has had the consequence of significantly reducing the market for Power Purchase Agreements (PPAs). However, it is only the larger generators, with ready access to the financial markets that can afford the cash reserves necessary to fund margin calls on ASX instruments. Financial market frictions therefore result in DG investors being unable to access most forms of hedging and facing volatile cash flows. For the average risk-averse investor this will result in a reduction in beneficial investment.

ACOT also provides a mechanism that enables the DG investor to internalise the dynamic efficiency benefits provided by DG investment. When there are beneficial externalities the absence of such a mechanism results in a market failure where the beneficial activity is under-provided (section 8.4).

2. INTRODUCTION

2.1. Background

In 2012 the Electricity Authority ("the Authority") introduced a radical proposal to reform transmission pricing. That proposal met with very limited support from across the industry. During the process of consultation on that proposal, the Authority was apparently surprised to learn of the existence of payments to embedded generators for "Avoided Cost of Transmission" (ACOT), and that such payments can be a significant source of revenue for some generators.

In an effort to gain support for its transmission pricing proposal, or at least to clear away the objections, the Authority has embarked on a revised process of consulting on a series of "Working Papers" which address specific issues. To date the Authority has issued working papers on the cost benefit analysis approach to be applied to the assessment of a revised transmission pricing methodology, and the definition of sunk costs.

On 19 November 2013 the Authority issued the third Working Paper in the series, focusing on "avoided cost of transmission payments (ACOT) for distributed generation" ("the Working Paper").

The Independent Electricity Generators' Association (IEGA) commissioned Andrew Shelley Economic Consulting Ltd (ASEC) to prepare this report in response to the ACOT Working Paper. The relevant qualifications and experience of ASEC's Principal, Mr Andrew Shelley, are set out in Appendix A.

2.2. Structure of this Report

This report is structured as follows:

- Section 3 discusses the concept of efficiency that is most relevant to the long term benefit of consumers, and how this relates to Best Practice Regulation;
- Section 4 highlights a number of issues related to the economics of markets and transmission cost recovery, including the measurement of avoided "costs" in a market, relevant trade-offs that the Commerce Commission has made in the economic regulation of Transpower, how ACOT avoids incentives for uneconomic investment, the true source of locational signals for investment in New Zealand's wholesale electricity market, and the economics of payments to older generation;
- Section 5 examines the impact of DG on transmission investment, including its role in the regulated transmission capital expenditure approval process, the reliability benefits of diversity and its impact on required transmission capacity, and the net economic benefits from DG displacing transmission;
- Section 6 briefly addresses the impact of DG on distribution networks.
- Section 7 addresses each of the areas the Working Paper identifies as "other benefits" that might be provided by DG, viz reduction in losses and constraints, competition benefits, efficiency benefits, and environmental benefits; and
- Section 8 discusses the other benefits that ACOT provides, specifically a price signal for reliability at peak periods, the consequential reduction in peak wholesale market prices, and the cash flow benefits for an investor in DG.
- Section 9 responds to each of the Authority's preliminary conclusions.

3. THE LONG TERM BENEFIT OF CONSUMERS REQUIRES A FOCUS ON DYNAMIC EFFICIENCY

The Authority's working paper uses the term "inefficient" without clearly defining the type of efficiency in question, and without clearly relating efficiency to the long-term benefit of consumers.

3.1. TYPES OF EFFICIENCY

Efficiency is generally defined as having three dimensions:

- Allocative, being the allocation of resources in the economy to the highest value uses;
- Productive, being the production of outputs at least cost; and
- Dynamic, being the maximisation of welfare over time due to investment and innovation that meets new demand, improves productivity, and improves quality.

For questions involving long-life capital investments in infrastructure the most important measure of efficiency is dynamic efficiency. If an investment with a relatively short life turns out to be "wrong" or a sub-optimal investment, it is a relatively short period of time until a more appropriate replacement investment can be made. But for long-life infrastructure investment, the consequence of the investment can be present for many decades.

These issues have been considered at length in Commerce Commission proceedings concerning Part 4 regulation. The Commerce Commission held that for network assets dynamic efficiency should generally be given greater weight than productive and allocative efficiency, going so far as to state:[1]

> *where there is potentially a trade-off between dynamic efficiency (i.e. incentives to invest) and static allocative efficiency (i.e. higher short-term pricing), the Commission will always favour outcomes that promote dynamic efficiency. The reason is that dynamic efficiency promotes investment over time and ensures the longer term supply of the service, which thereby promotes the long-term benefit of consumers (consistent with outcomes in workably competitive markets).*

Appendix D in the Working Paper does provide a calculation of estimated productive inefficiency, but there is no attempt to estimate dynamic efficiency benefits, and no consideration of whether other aspects of the wholesale electricity market might be equally inefficient. It is generally accepted that real world markets do involve inefficiencies, with trade-offs being made between the inefficiencies of, say, co-ordination of plant via a price mechanism rather than central planning, and the efficiency gains arising from having the profit motive to (a) optimise the organisational and operating costs of plant and (b) optimise long-term capacity investment. Some of the benefits of a market are exceedingly hard to quantify, yet we accept that the market mechanism delivers "more" efficient outcomes, even if they are not necessarily "most" efficient as judged against the benchmark of what could be achieved with perfect information.

1 New Zealand Commerce Commission, *Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper*, 22 December 2010, Para H1.31, p. 395.

A more relevant question to ask is whether, over a long time horizon, aggregate consumer welfare is best served by increasing transmission into a constrained region or by building DG within that region. Section 5.5 and Appendix B of this paper presents a simple model for calculating the dynamic efficiency benefits of DG.

3.2. Long-Term Benefit of Consumers

Section 15 of the Electricity Industry Act 2010 provides the Authority with the statutory objective:

> *To promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers*

The Authority is not the only body to have a statutory purpose statement requiring a focus on the long-term benefit of consumers. The Commerce Act provides the Commerce Commission with a similar purpose.

Section 1A Commerce Act 1986 has the general purpose:

> *The purpose of this Act is to promote competition in markets for the long-term benefit of consumers within New Zealand.*

Section 52A provides the following purpose for Part 4 of the Commerce Act, concerning regulated goods and services:

> *(1) The purpose of this Part is to promote the long-term benefit of consumers … by promoting outcomes that are consistent with outcomes produced in competitive markets …*

The meaning of “long-term benefit of consumers” was subject to extensive consultation by the Commerce Commission during the Input Methodologies process. The term was generally held by experts and the Commission alike to be consistent with a focus on dynamic efficiency.

3.3. Best Practice Regulation

Mumford (2011) sets out the New Zealand Treasury’s best practice regulation framework.[2] The attributes, principles, and indicators of that framework are summarised in Table 1 overleaf. Regardless of the fact that the Authority has a single statutory objective, it is also a regulatory body and should comply with the principles of Best Practice Regulation.

One attribute of Best Practice Regulation is that it is “certain and predictable”, with the regulatory regime being predictable over time. Both that attribute and the “growth supporting” attribute include an indicator that requires the need for firms to take long-term investment decisions into account. The potential removal of ACOT, whether directly or by way of major changes to the transmission pricing methodology, is not consistent with these indicators, as investment decisions have been made with the expectation of some form of continuing ACOT payment. Eliminating these payments will adversely affect investment incentives.

2 Mumford, Peter (2011) “Best Practice Regulation: Setting Targets and Detecting Vulnerabilities”, *Policy Quarterly*, 7(3):36-42.

Table 1: Best Practice Regulation Principles and Indicators

Attribute	Principle	Indicators
Growth-supporting	Economic objectives are given an appropriate weighting relative to other specified objectives	1. Identifying and justifying trade-offs between economic and other objectives is an explicit part of decision making 2. **The need for firms to take long-term investment decisions is taken into account** in regulatory regimes where appropriate 3. Open and competitive domestic and international markets an explicit objective
Proportional	The burden of rules and their enforcement should be proportionate to the benefits that are expected to result	1. A risk-based, cost-benefit framework is in place for both rule-making and enforcement 2. There is an empirical foundation to regulatory judgements
Flexible and durable	Regulated entities should have scope to adopt least-cost and innovative approaches to meeting legal obligations The regulatory system has the capacity to evolve to respond to changing circumstances	1. The underlying regulatory approach is principles- or performance-based, and policies and procedures are in place to ensure that it is administered flexibly 2. Non-regulatory measures, including self-regulation, are used wherever possible 3. Feedback systems are in place to assess how the law is working in practice 4. Decisions are reassessed at regular intervals and when new information comes to hand 5. The regulatory regime is up to date with technological and market change, and evolving societal expectations
Certain and predictable	Regulated entities have certainty as to their legal obligations, and **the regulatory regime provides predictability over time**	1. Safe harbours are available and/or regulated entities have access to authoritative advice 2. Decision-making criteria are clear and provide certainty of process 3. **The need for firms to take long-term investment decisions is taken into account** in regulatory regimes where appropriate 4. There is consistency between multiple regulatory regimes that affect single-regulated entities where appropriate
Transparent and accountable	Rules-development, implementation and enforcement should be transparent	1. Regulators must be able to justify decisions and be subject to public scrutiny
Capable regulators	The regulator has the people and systems necessary to operate an efficient and effective regulatory regime	1. Capacity assessments are undertaken at regular intervals and subject to independent input and/or review

Source: Mumford (2011), p. 37. (emphasis added)

4. THE ECONOMICS OF MARKETS AND TRANSMISSION COST RECOVERY

The Working Paper makes several concerning statements which suggest that the Authority does not have a clear understanding of the way that markets work.

4.1. AVOIDED COSTS IN A MARKET

There seems to be a significant concern in the Working Paper that ACOT payments might not reduce accounting costs. For example, section 7 is titled with the question "Do ACOT payments reduce transmission costs?", followed immediately by the subtitle with the question "Do consumers benefit from ACOT through reduced transmission charges?". The remainder of the section is clearly focussed on both the total quantum of Transpower's charges and the charges paid by an individual distributor.

Avoided charges in a market almost never reflect avoided short-run costs, except when there is so much excess capacity that goods and services are sold at marginal cost, and even that will not reflect variable accounting costs. A price can generally be thought of as recovering variable accounting costs, the margin of marginal cost over accounting variable costs, an allocation of fixed accounting costs, and a return on investors' capital. What is most important is to note that *price includes an allocation of fixed accounting costs*. **In *any* market where price exceeds variable accounting cost it will always be the case that a reduction in demand results in a reduction in revenue for the supplier that *exceeds* variable accounting costs.** This is just how markets and the price mechanism work. The Authority should not be surprised, therefore, that the reduction in transmission charges that occurs with a reduction in demand is greater than any underlying reduction in transmission costs.

4.2. ECONOMIC REGULATION OF TRANSMISSION

What does differ from a market is that Transpower is able to shift the recovery of fixed costs on to other parties. A workably competitive market offers very little opportunity for a supplier to raise prices to other customers when one customer reduces demand. A small increase may be possible in a competitive market, but an increase that is too large will be met by customers changing suppliers. Transmission is not, however, a competitive market, so such behaviour is possible. Furthermore, such behaviour is an integral part of the economic regulation for Transpower because of a judgement that has been made about the relative costs and benefits of different forms of regulation.

When establishing the most appropriate form of economic regulation for Transpower, the following questions should be asked:

- Should a small consumer be able to reduce the portion of transmission charges paid by installing energy-efficient appliances (thereby reducing demand at peak)?
- Should a small consumer be able to reduce the portion of transmission charges by installing solar thermal (thereby taking advantage of stored heat for both space and water heating and thereby reducing demand at peak)?
- Should a small consumer be able to reduce the portion of transmission charges by load-shifting to off-peak times?

The answer to those questions would, for most people, undoubtedly be "yes". The direct implication of this is that there should be an element of transmission charges which is variable and avoidable.

A further important question in the economic regulation of Transpower is whether there are benefits from Transpower having a stable revenue stream. Distributors have a weighted average price cap, which means that they do suffer reduced revenue when demand reduces. Transpower, on the other hand, has a revenue cap, which insulates it from changes in demand. It was argued that a revenue cap was appropriate for Transpower because it would provide better long-term investment incentives and thus promote dynamic efficiency. The appropriate forum to address this question is the consultation being run by the Commerce Commission this year on Transpower's Price-Quality Path from 2015-2020.

4.3. Avoiding Incentives for Uneconomic Investment

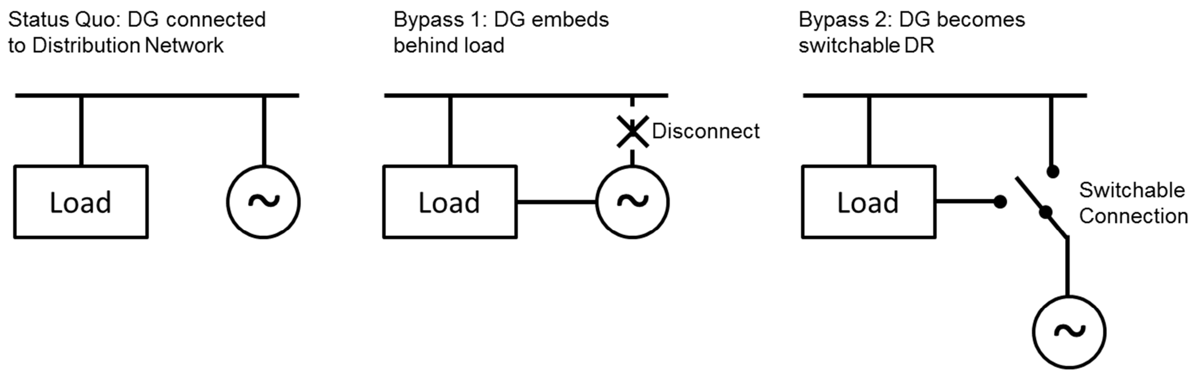
It is then important to recognise that electricity delivered to a consumer via "traditional" means (i.e. transmission and distribution) is nothing more than delivered energy. There are many other forms of delivered energy. The solar thermal mentioned above is one example. Natural gas is another, as is biofuel such as wood.

Another source of delivered energy is DG. Small consumers may have solar PV, wind, or even small in-stream hydro generation. There is no reason why these sources of delivered energy should be discriminated against any more than other ways of reducing load on the distribution and transmission network. If DG reaches a level where it exports on to the distribution network, and exports are sufficiently high that additional costs are caused, then it would be appropriate to charge for those costs. But efficient markets would not allow discrimination to occur – discrimination between sources of load reduction is nothing more than "picking winners" and will result in an allocatively and dynamically inefficient allocation of resources.

The next level is to consider larger consumers and larger sources of DG, and then DG that is embedded within a distribution network and not shielded behind a load. The left-hand panel of Figure 1 shows the status quo with a load and DG (signified by the symbol ~) separately connected to the distribution network. Transmission is charged on the net load, and ACOT is paid to the DG.

Now assume that ACOT is no longer paid. The middle panel shows one bypass option: the DG disconnects from the distribution network and embeds behind a nearby load. Peak charges for the load are reduced by the amount of generation at peak, and that reduction in charges is shared between the load and the DG.

Figure 1: Example Embedding Options



The right-hand panel of Figure 1 shows a second bypass option: in this case the generator retains its connection to the distribution network, but invests so that it can switch between that direct connection and embedding behind a nearby load. In effect, the generation becomes switchable demand response. The generator can be switched to embed behind the load either when peaks occur or when demand response from the load is dispatched. The benefits from peak reduction and demand response are shared between the load and the generation.

In both of the bypass cases the removal of ACOT provides an incentive to achieve the same outcome by another means. It is not efficient to build additional electrical assets simply to achieve the same result as ACOT, but if there are profitable opportunities then rational profit-maximising economic agents will take advantage of them.

In all cases a competitive and efficient market would not allow discrimination to occur. DG connected to the distribution network should be treated the same as DG shielded by a load within the distribution network, otherwise incentives will exist to shield the DG by building additional infrastructure (i.e. a connection between the DG and a nearby concentration of load), with no economic benefit derived.

4.4. Locational Signals

The Working Paper expresses some surprise and/or concern that the location of DG seems to reflect the location of fuel supplies rather than the location of congestion in the transmission network.

This should not be at all surprising. The Authority will be aware that locational variations in wholesale electricity prices are insufficient to fund transmission expansion. Why, then, should it be expected that the same variation would be sufficient to fund generation? Locational variations in wholesale electricity prices are swamped by year-to-year variation in prices and by the myriad of other costs and uncertainties that an investor must face. Theoretically precise prices are of no practical use if the price signal is swamped by other factors.

The only true locational signal is given by Transpower's interconnection charge. That charge has a long history of development:[3]

- Prior to the introduction of the market, a non-locational capacity charge and locational network charge (based on the average of multiple load flow allocations conducted over the top 25% of system peak half hours, with those load flows averaged over a period of up to 5 years);
- With the introduction of the market, a non-locational access charge and locational transport charge (based on a single load flow);
- When the results of the single load-flow proved highly volatile, a move to just the non-locational Access charge;
- Replacement of the Access charge with a non-locational Interconnection charge, which is essentially identical to the Access charge;

3 I was working as a Pricing Analyst and then Strategic Analyst at Transpower from 1995-1998, specifically working on the transmission pricing methodology. The commentary that follows on transmission pricing is my personal testimony.

- Further refinement of the peak charging mechanism for the Interconnection charge to create a charge based on regional peak across four broad regions (Lower South Island, Upper South Island, Lower North Island, and Upper North Island).

The change in transmission pricing with the introduction of the market was driven by desire from the demand side to have pricing that was simpler (the move away from the multiple load flows), and more responsive to changes in demand (the move away from long period averaging to a single year). Transpower remained rightly concerned that charges might be too responsive to changes in demand, not reflecting true reductions in demand if the reductions were achieved by way of unreliable DG, so a variety of mechanisms were developed to charge at or near the recent historical peak.

Notwithstanding these changes in methodology, there was a continued acceptance that the interconnected transmission network provided a combination of benefits that were location-independent (hence the Capacity and Access charges) and location-dependent (hence the Network and Transport charges). The current Interconnection charge has a location-independent rate, but the charging methodology introduces a very broad locational signal.

The changes to the pricing methodology with the introduction of the market were discussed and agreed by the Grid Services Working Group, chaired by Patrick Strange.

The move away from a locational component was justified retrospectively with the notion that the grid assets are sunk and there is therefore no reason to send a locational signal. It is important to recognise, however, that:

- The true reason for moving away from a locational signal was that the single load flow approach produced prices that were too unstable; and
- The original locational approach was coupled with an understanding of the economic logic that price signals for sunk assets are appropriate if those price signals will influence future investment requirements.

Avoided interconnection charges provide the only significant locational price signal for DG, and for the reasons outlined above interconnection is currently independent of location. This means that DG has the same locational investment incentives as grid-connected generation, which is to locate at the “best” (lowest cost) fuel supplies.

4.5. Payments to Older Generation

A second area of concern is the suggestion in paragraph 10.1 that:

> *The Authority has identified two particular situations where, in theory at least, ACOT payments could result in inefficient subsidies to DG:*
>
> *(a) where distributors own DG*
>
> *(b) where ACOT payments are made to older generation plant.*

It is agreed that distributor-owned DG could give rise to inefficient outcomes if that DG was given preferential treatment in a range of areas. The solution to this is not to make ACOT available to only a subset of DG, nor to “outlaw” ACOT. The solution is to require that distributors have non-discriminatory treatment of DG: connection terms and prices for distributor-owned DG should be disclosed (transparency to eliminate the information asymmetry), and there should be a mechanism for rapid dispute resolution (lowering the cost of dispute resolution).

The more concerning statement is the suggestion that paying ACOT to older generation plant is inefficient. In making this statement, the Authority is striking at the heart of the market mechanism as a desirable way to co-ordinate economic activity.

In the first instance, peak demand charges have been in existence since at least the 1950s. Some generation plants have been "over-engineered" relative to what is required on an energy-only basis, specifically so that they have the capacity and reliability necessary to reduce peaks. Much of this investment took place before the introduction of the market, so was not an opportunistic "profit grab" but instead was a considered response by engineers to the requirements of the system. It is reasonable to infer that there was an expectation that peak charges would continue into the indefinite future, and the cost of the over-engineering was always intended to be recovered from those avoided charges rather than from energy charges.

In any market the price is set by the marginal supplier, or by a number of suppliers providing supply at the same marginal cost. All other units of supply are provided at a cost that is less than the market price – these units of supply are called "inframarginal" units. The difference between market price and cost is called a "rent". Rents contribute to the payment of fixed costs, and may provide a further positive surplus. All inframarginal units earn an economic rent. In the wholesale electricity market there is significant grid-connected generation capacity that was built decades in the past and earns rents every time that it is an inframarginal unit.

Inframarginal rents should not be confiscated simply because the plant is "older", yet that is precisely what the Authority implies is desirable for distributed generation. On the contrary, to quote recent analysis by the Authority:[4]

> *This analysis finds no evidence of windfall gains over historical generation costs accruing to generators or retailers.*

That statement is also true of the Authority's analysis of DG. There is no evidence of DG earning windfall gains over historical generation costs, so that provides no basis for the removal of ACOT.

It has long been recognised that it is the search for rents that drives economic activity and innovation. An investor is not motivated to simply earn average returns: an investor is motivated by the search to earn above-average profits, which would occur where rents are the greatest. In the electricity market an investor seeks to invest in a new plant that will be inframarginal, and thus earn more than the cost of bringing the supply to market.[5] Over time this leads to an expansion of supply and a decrease in prices.

Some suppliers in a market may have a long-term advantage that enables them to earn rents over the long term. This does not make the market inefficient. However, a regulatory action to confiscate those rents could have the undesirable side effect of creating investor perceptions of potential future confiscations, thereby dampening investment incentives. Any decisions to invest now or in the near term will have to take account of the possibility that an expected income stream may be eliminated by regulatory fiat in future. This will have a chilling effect on investment, thereby harming the long-term interests of consumers. This would not be consistent with the Best Practice Regulation principles introduced in section 3.3.

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4 Electricity Authority, *Analysis of historical electricity industry costs*, Final report, 21 January 2014, p iii.

5 This point is made by the Authority in its discussion of "windfall returns" in Layton, Brent (2013) "The Economics of Electricity", 4 June, p. 12, para. 38.

5. IMPACT OF DG ON TRANSMISSION INVESTMENT

5.1. THE WORKING PAPER

Section 8 of the Working paper addresses the question of whether ACOT payments reduce transmission investment. Based on a cursory examination of Transpower's Asset Management Plans, the Working Paper's conclusion is that (para 8.6):

> *ACOT-funded DG appears to have quite limited impact on Transpower's peak demand forecasts, and hence limited ability to defer the assessed need for transmission investment.*

The Working Paper does not show that ACOT-funded DG has had no effect on transmission capital investment. We would expect to see a list of transmission capital expenditure projects over the period of interest and a specific assessment of each project as to the reason why it has occurred. Some capital investment is, for example, due to replacement of aging assets. We would also expect to see an analysis of areas where DG is prevalent, to determine the quantum of additional transmission that would be required if the DG was not present. The absence of evidence is not the same as positive evidence in support of a conclusion.

This section of the Working Paper also contains a number of spurious comments of limited relevance, including:

- *Additional generation in a region may bring forward transmission investment rather than defer or reduce investment.* (para 8.12)

  This is true whether generation is grid-connected or embedded/distributed. The real issue here is whether the TPM and capital expenditure methodology provides an appropriate signal for generation investment regardless of the precise means by which that generation is (eventually) connected to the transmission grid.

- *None of the eighteen off-take points demonstrated a reduction in demand (which could be an indication of DG). (para 8.12)*

  If DG installation is "often comparable to the rate of annual demand growth" (para 8.15) then overall net demand growth would be expected to be generally flat (i.e. little or no growth). In addition, 18 "off-take points" represents a considerable degree of aggregation, and it may be that within some of those off-take points there has been a reduction at one GXP and an increase at another.

5.2. DG EXPLICITLY DEFERS TRANSMISSION UPGRADES IN TRANSPOWER'S ANNUAL PLANNING REPORT

While we cannot speak for Transpower, the Working Paper seems to mischaracterise Transpower's view on whether generation can provide an adequate substitute to transmission. As the level of local generation grows, the reliability of that generation benefits greatly from diversity (see section 5.4 below). As Transpower itself states (quoted in para 8.22 of the Working Paper), "a reliability level of 99% to 99.9% may be achievable". If this reliability can be achieved at peak, then it can certainly be achieved off-peak and a combination of DG and DSM may be the economically preferred option.

Furthermore, Transpower have advised the IEGA that they do consider DG in their demand forecasts. This is clearly evident when reading Transpower's 2013 Annual Planning Report.[6] For example, in just the chapter concerning the West Coast region there are four areas where additional DG will help relieve a pending upgrade. Each of these four areas are outlined below.

Inangahua–Murchison–Kikiwa transmission capacity

A thermal upgrade of the 110kV transmission capacity is required in approximately 2022. However, Transpower notes that:

> *Initial application of the Grid Investment Test indicates the upgrade has no economic benefit.*

Additional options are therefore required. Although not mentioned, one obvious option is to increase regional generation so that the thermal upgrade is not required.

Kikiwa interconnecting transformer capacity

Transpower states:

> *The loss of the Stoke interconnecting transformer means the Kikiwa interconnecting transformer supplies both the West Coast and Nelson-Marlborough load, which may overload for:*
>
> - *high West Coast and Nelson-Marlborough loads, and*
> - *low generation in the West Coast and Nelson-Marlborough regions*

The longer term option is to replace the existing transformer with higher rated transformer. However, Transpower states:

> *This issue may be **managed operationally with generation** from Cobb and Kumara for the forecast period (provided water is available). Transpower will work with the generators to manage this constraint.*
>
> [emphasis added]

A further solution would be the development of further generation resources so that low generation conditions do not arise.

Dobson supply transformer capacity

Transpower states:

> *The peak load at Dobson is forecast to exceed the transformers' n-1 winter capacity by approximately 1 MW in 2024, increasing to approximately 2MW in 2028, assuming 3MW from the embedded generation at Arnold.*
>
> *Arnold is very reliable in producing 3MW of generation, so its output is considered in the overload forecast. Without Arnold, there is an overload of 1 MW in 2013, increasing to 3MW in 2020.*

The important point here is that existing DG is deferring a transmission upgrade by 11 years.

Transpower's solution to the pending need for an upgrade is:

> *We will use operational measures (Arnold **generation**) in the short to medium term.*

6 Transpower, *2013 Annual Planning Report*, 30 March 2013.

> *Possible longer-term options include resolving the transformers' protection and LV cable limits (providing n-1 capacity beyond the forecast period) or **increasing the embedded generation**.*
>
> *Options will be investigated closer to the need date.*
>
> [emphasis added]

Increasing embedded generation is an option explicitly identified by Transpower.

Hokitika transmission capacity

Transpower states:

> *[A] system reconfiguration … maintains n-1 security to Hokitika by providing two higher-capacity circuits.*
>
> *The overloading then shifts to the Dobson–Greymouth circuit. Options to address this issue include **constraining on generation** at Kumara, thermally upgrading the circuit, or load transfer from Greymouth to Dobson.*
>
> *The previous investigations, however, also indicated that the system reconfiguration may be uneconomic. An **alternative is to automatically reduce load** at Hokitika following a circuit outage, causing a partial loss of supply.*

Constraining on generation is an explicitly identified option, which also implies that additional local generation would also be beneficial. Automatic load reduction is also an identified alternative, and load reduction is the same as additional generation.

These examples are not one-off occurrences that have not previously needed to be considered. Remaining with the West Coast region, the recent upgrade of the 110kV line from Inangahua to Dobson provides another example of the ability of DG to significantly defer transmission upgrades. ECNZ began planning for a new line into the West Coast during the late 1980s as demand began to increase. However, due to the impact of the 10MW Kumara Hydro scheme which had been commissioned in 1978, Transpower was able to maintain supply to the West Coast even in the event of an outage of one of the two main transmission lines into the area. The new line was eventually built and commissioned in late 2011. This project was one of the first to be approved under the Grid Investment Test with the justification being the need to supply the additional estimated load of 14 MW from the Pike River Coal mine. Without that additional expected step load, it is unlikely that the project would have been approved and the West Coast would still be relying upon the Kumara scheme for security of supply to the area.

Additional examples are not difficult to identify, such as: reinforcement of the transmission lines into Buller Electricity to support local load growth is delayed because of the development of the 5MW Kawatiri Energy scheme; and Alpine Energy are able to avoid investment in a duplicate feeder between Albury and the transmission network because Opuha is able to generate to support the local load.

5.3. Transmission Capital Expenditure Process

Transpower's major capital expenditure programme must be approved by the Commerce Commission under the Transpower Capital Expenditure Input Methodology Determination [2012]. Under that determination, investment must demonstrate a net electricity market benefit or be required under the deterministic limb of the grid reliability standards (D1(b)). Under D5(1), computation of the electricity market benefit includes, *inter alia*:

> *(b) the cost of involuntary demand curtailment borne by end users of electricity*
>
> *(c) the costs of demand-side management;*

(d) capital costs of modelled projects;

(e) costs resulting from operations and maintenance expenditure on committed projects, existing assets and modelled projects;

However, under D9(4)(b) the only modelled projects that need to be considered are those:

for which the likelihood, nature and timing of their existence are affected by an investment option proceeding.

Demand forecasts for the relevant calculations are prepared by the MBIE (or as an interim measure by Transpower having made any necessary adjustments to the Electricity Commission's 2010 forecasts). Those forecasts will be net demand forecasts, using actual demand as a historical base, and will not explicitly model every source of DG. It will therefore not be apparent to what extent DG is affecting the forecasts that are used for capital expenditure proposals. Furthermore, the only projects that are likely to be modelled are larger scale projects that specifically require a transmission upgrade in order to proceed. Smaller projects that delay or permanently defer an upgrade will never feature in any analysis.

5.4. The Reliability Benefits of Diversity and its impact on Required Transmission Capacity

Table 2 overleaf shows how even relatively unreliable generation units can benefit from diversity and provide a high level of combined reliability. For this example we assume that 20% or 40% of peak demand is potentially met by a combination of unreliable generation units (70% reliability, independent failure).

With 5 units each equal to 4% of peak capacity, the following is observed:

- Transmission capacity of 88% of peak load is required to meet the reliability target of 99.0% of weighted average peak load served;
- On the stated reliability target, the combined reliability of the units is equivalent to having a single generation unit of 20% of peak load, with a reliability of 93.42%

With 10 units each equal to 2% of peak capacity (i.e. twice as many units of half the size), the following changes are observed:

- Required transmission capacity reduces slightly to 87% of peak load;
- The equivalent reliability of a single generation unit of 20% of peak load increases slightly to 94.04%.

With 10 units each equal to 4% of peak capacity, the following changes are observed:

- Required transmission capacity reduces to 76% of peak load;
- The equivalent reliability of a single generation unit of 40% of peak load capacity is 96.46%.

The combined reliability of multiple unreliable generation units is very high when compared with an appropriate level of transmission. What constitutes an appropriate level of transmission depends on the quantity of generation, and is potentially considerably less than the gross peak load. This demonstrates that, at least from this perspective, DG *should* be able to displace transmission investment, even when that investment is governed by a reliability standard. If this is not occurring then it is the cause of the problem that should be reviewed (i.e. the capital investment approval process, including both the criteria and the data that feeds into the process), rather than addressing the symptom of DG that apparently does not affect transmission investment.

Table 2: Reliability Benefits of Multiple Units and Impact on Required Transmission Capacity

Number of Units	5	10	10
Unit Size	4	2	4
Total Generation	20	20	40
Transmission Capacity	88	87	76
Transmission Reliability	99.90%	99.90%	99.90%
Unit Reliability	70%	70%	70%
Weighted Peak Load Met	99.13%	99.14%	99.09%
Equivalent Single-Unit Reliability	93.42%	94.04%	96.46%

Notes: Unit reliability = 70%; transmission reliability = 99.9%;reliability target = 99.0%; gross demand at peak = 100.

5.5. Net Benefit from DG Displacing Transmission

The dynamic efficiency gain from DG can be estimated by calculating the NPV of investment costs with DG and comparing that to the NPV of investment without DG. This could potentially be performed using a system-wide investment model, but for illustrative purposes we will focus on a hypothetical small region within the grid.

In broad terms, the key inputs required are:

- Transmission investment costs;
- Wholesale electricity price path;
- DG investment costs;
- Load characteristics (current value, load growth); and
- Discount Rate.

The assumptions for each of these items are described in Appendix B.

The analysis in Appendix B assumes that transmission investment is, ultimately, linked to peak demand. When net demand reaches a certain proportion of available capacity (assumed at 95%) then investment will occur so as to avoid any unserved energy. Consistent with the Working Paper's statement that growth in DG capacity is "often comparable to the rate of annual local demand growth" (para 8.15), the analysis includes a scenario where growth in DG is equal to 100% of demand growth, as well as a scenario where it is equal to only 50% of demand growth. These percentages reflect the growth of generation capacity; generation actually available at peak is de-rated by a "Peak Availability Factor" which reflects the likely contribution of each type of generation to peak.

Table 3 summarises the results of the analysis. As shown in that table, dynamic efficiency benefits from DG displacing transmission are estimated at $1.9m to $7.3m for a small load centre of 125MW. Any costs from DG arise in the first five years, when NPV-weighted prices are less than the long-run marginal cost of the generator. Over the same period the growth in gross load is only 10MW.

Table 3: Summary of Results

Scenario Description	Present Value ($000)			
	Distributed Generation	**Transmission**	**Total**	**Benefit vs Scenario 1**
Scenario 1: No DG	$0	$11,130	$11,130	$0
Scenario 2: DG growth equal to 50% of load growth	$0	$9,262	$9,262	$1,867
Scenario 3: DG growth equal to 100% of load growth	$204	$3,582	$3,785	$7,345

The question then arises of how to convert these benefit values to something more comparable with the per-household cost included in the Working Paper. Using statistics derived from the Electricity Distribution Information Disclosure, the weighted average demand is 3.0kW/ICP.[7] This implies that 41,667 ICPs would generate a demand of 125MW.[9] Transpower's Annual Planning Report indicates that Transpower has 11,730 route km of HVAC and HVDC transmission line. If converted to km/ICP, the average transmission line length required to service 41,667 ICPs is 240.5km, some 4.81 times the length assumed in Table 3. Sensitivity analysis reported below indicates that net benefits are directly proportional to transmission line length. Dividing the benefit through by the present value of the number of ICPs over time, and multiplying by the transmission line length multiplier implies that the benefit of DG is between $7.58 and $29.82 per ICP per year.

While the analysis in Appendix B ultimately relies on a fairly simple model of investment, it anchors the assumptions to real-world examples. Unlike the Authority's estimate of productive inefficiency, it is not just based on broad unjustified assumptions. It could be improved however, by adopting a system-wide equilibrium model. This task is left to Authority staff.

In 2008 Maunsell Ltd prepared an analysis for the Energy Efficiency and Conservation Authority (EECA) of the costs and benefits of connecting DG to distribution networks.[11] Maunsell estimate the cost of transmission upgrades as $252,000 per MW per year, and calculate that DG penetration of 50% would have a reduction in transmission system NPV costs of 46.5%. Lower levels of DG penetration achieved a similar proportional reduction in transmission system NPV costs (10% DG penetration achieved a 9.3% reduction in NPV costs, 25% DG penetration achieved a 23.2% reduction in NPV costs).

Maunsell assumes a cost of transmission investment of $252,000 per MW, which implies a 210km transmission line given the cost of $1,200/km/MVA assumed in the present analysis. This is in the same order of magnitude as the 240km used in the calculation above. A transmission line of 210km length would result in a calculated benefit of between $6.62 per ICP and $26.04 per ICP.

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7 Commerce Commission, *Compendium of completed EDB ID Schedules 1–10 templates for Disclosure Year (year ended) 31 March 2013*, v1.1 Excludes OtagoNet and transitional year schedules, 29 November 2013. Total ICPs are 2,032,055 after adjustments to Electra data to exclude ICPs that are counted for multiple tariffs.

9 23.15kW x 5,400 = 125.01MW.

11 Maunsell Ltd, *Costs and Benefits of Connecting Distributed Generation to Local Networks*, Final Report, Energy Efficiency and Conservation Authority, 24 September 2008.

It could perhaps be argued that the benefits of deferring or avoiding transmission investment will be most prevalent at the extremities of the grid, and less likely to occur in the core grid. The figure of 240km of transmission line for the assumed load will include both categories of transmission line. Without conducting a more detailed analysis, a lower bound estimate of the benefits might be obtained by assuming a transmission line multiplier of, say, 2.5 (equivalent to 125km of transmission line). This yields a benefit of between $3.94/ICP and $15.50/ICP.

To summarise the results of this analysis, low levels of DG penetration may result in net benefits from avoided transmission investment of between $3.94/ICP and $7.58/ICP. High levels of DG penetration may result in net benefits from avoided transmission investment of between $15.50/ICP and $29.82/ICP. To the extent that ACOT prevents market failure by enabling DG to internalise the benefits of reduced future transmission investment and reducing the relative risk of DG cash flows, at high levels of DG penetration the benefits induced by ACOT exceed the $10.29 per household cost calculated by the Authority. This suggests that if the Authority's focus is on long term benefits to consumers, it should be seeking to reduce the barriers to increased DG penetration rather than reducing or removing ACOT payments.

5.6. Sensitivity Analysis

Sensitivity analyses were conducted for the following parameters:

- Discount rates of 2%, 6%, and 8%;
- Different DG options;
- Transmission line length 25km and 100km; and
- Transmission line cost $900/MVA/km and $1,500/MVA/km.

The detailed results of the sensitivity analysis are presented in Appendix B.9.

Benefits are directly proportion to transmission line length, i.e. doubling or halving transmission line length will double or halve the corresponding net benefits. Elasticity with respect to transmission (capital) line cost is in the range 0.8-0.9, so a given change in transmission line capital cost will induce a less than proportional change in net benefit. The reason for this is that a portion of transmission costs is O&M costs on existing assets, and that remains constant even when capital costs change.

The elasticities for the sensitivity to discount rates are as follows:

- Under scenario 2, the net benefit increases with a change in discount rate (elasticity is positive) but the proportional change in net benefit is less than the proportional change in discount rate (elasticity is less than one). Elasticity values depend on the discount rate.
- Under scenario 3, the net benefit changes in the opposite direction to the change in discount rate, i.e. an increase in the discount rate results in a reduction in net benefit. The elasticity is approximately -0.3 for all discount rates.

The elasticities for the sensitivity to the DG option chosen can be very large. Net Benefits can change significantly (including to a large net cost) depending on the generation project, with benefits generally being negative for Small Scale Distributed Generation (SSDG). It is important to recognise that the investment incentives for SSDG are quite different from those for larger scale DG: investments in SSDG are made by consumers, responding to a range of factors including a desire to be “green” and potential subsidies. ACOT is not a significant determinant of the decision to invest in SSDG, and removal of ACOT is unlikely to have any effect on such investments. However, removal of ACOT is likely to negatively affect investment in larger scale economically beneficial DG.

6. IMPACT OF DG ON THE DISTRIBUTION NETWORK

Although ACOT payments are by definition concerned with transmission, section 9 of the Working Paper considers the question of whether ACOT payments avoid distribution investment or costs. Based on a very select sample of distributor Asset Management Plans, the Working Paper concludes (para 9.12, p. 34):

> *DG can create benefits under a very particular set of circumstances but there are also likely to be costs, particularly without better energy storage, and that costs may increase as DG becomes more predominant.*

Maunsell's analysis[12] includes a detailed consideration of the costs and benefits for the distribution network from increased penetration of DG, specifically those arising from:

- Network losses;
- Voltage;
- Power Factor Correction;
- Increased Fault Level;
- Reliability/Availability;
- Network Upgrades;
- Protection;
- Harmonics; and
- Intermittency of DG dispatch.

Maunsell estimated that 50% DG penetration could reduce the NPV of distribution costs by between 24.1% and 28.8%, depending on the voltage level at which the DG was connected. Lower levels of DG penetration had commensurately lower reductions in the NPV of distribution costs. Reliability of supply to end consumers improves with DG, with unavailability reducing from approximately 1418 seconds per year to 502-511 seconds per year.

The Authority has not considered Maunsell's analysis in its discussion of the impact of DG on the distribution network, and nor does the Authority's analysis provide a convincing rebuttal to that of Maunsell. Maunsell's paper is readily available, being located in the same location on EECA's website as the Centre for Advanced Engineering report that is cited in the Working Paper.[13]

12 Footnote 11, supra.

13 See http://www.eeca.govt.nz/distributed-generation.

7. WHAT OTHER ROLE DOES DG PLAY?

7.1. THE WORKING PAPER

Section 11 of the Working Paper asks whether DG provides other economic benefits or costs that might merit ACOT payments. As with the rest of the Working Paper, the analysis in that section is less robust than it could be.

The Working Paper proposes four areas of potential benefit and cost:

- savings from losses and constraints;
- competition benefits;
- environmental benefits;
- additional costs of less economic generation being constructed.

Each of the above areas is addressed below.

7.2. LOSSES AND CONSTRAINTS

It is a little disingenuous to claim (para 11.5) that "losses and constraints are … reflected in wholesale market prices so there would appear to be no substantive case for additional compensation for DG." For a marginal change in electricity consumption or net load this statement is true. But for a significant change it is not true.

A significant reduction in net load will reduce losses and constraints. If the reduction in net load is due to generation then the generator will be paid the new, lower, wholesale market price. The generator will not receive the benefit of the higher wholesale price that was prevailing prior to the additional generation. This is not a new result, and has been a recognised problem in transmission investment for many years. If transmission investment is made to relieve a constraint then the constraint rentals that existed prior to the investment will disappear and cannot be used to fund the investment.

We conclude, therefore, that the benefits of a reduction in loss and constraint rentals are encapsulated in wholesale market prices for small scale DG, but the reduction in losses and constraints that may occur as a result of larger scale DG will not be compensated, and at the margin this could lead to DG being under-provided (i.e. it would be a source of market failure).

7.3. COMPETITION BENEFITS: RETAIL MARKETS ARE REGIONAL

In paragraph 11.11, the Authority makes the pronouncement that "the wholesale and retail markets for electricity are considered to be national markets", and provides a reference to a Commerce Commission investigation report. Following that link, the Commerce Commission has a different view:[14]

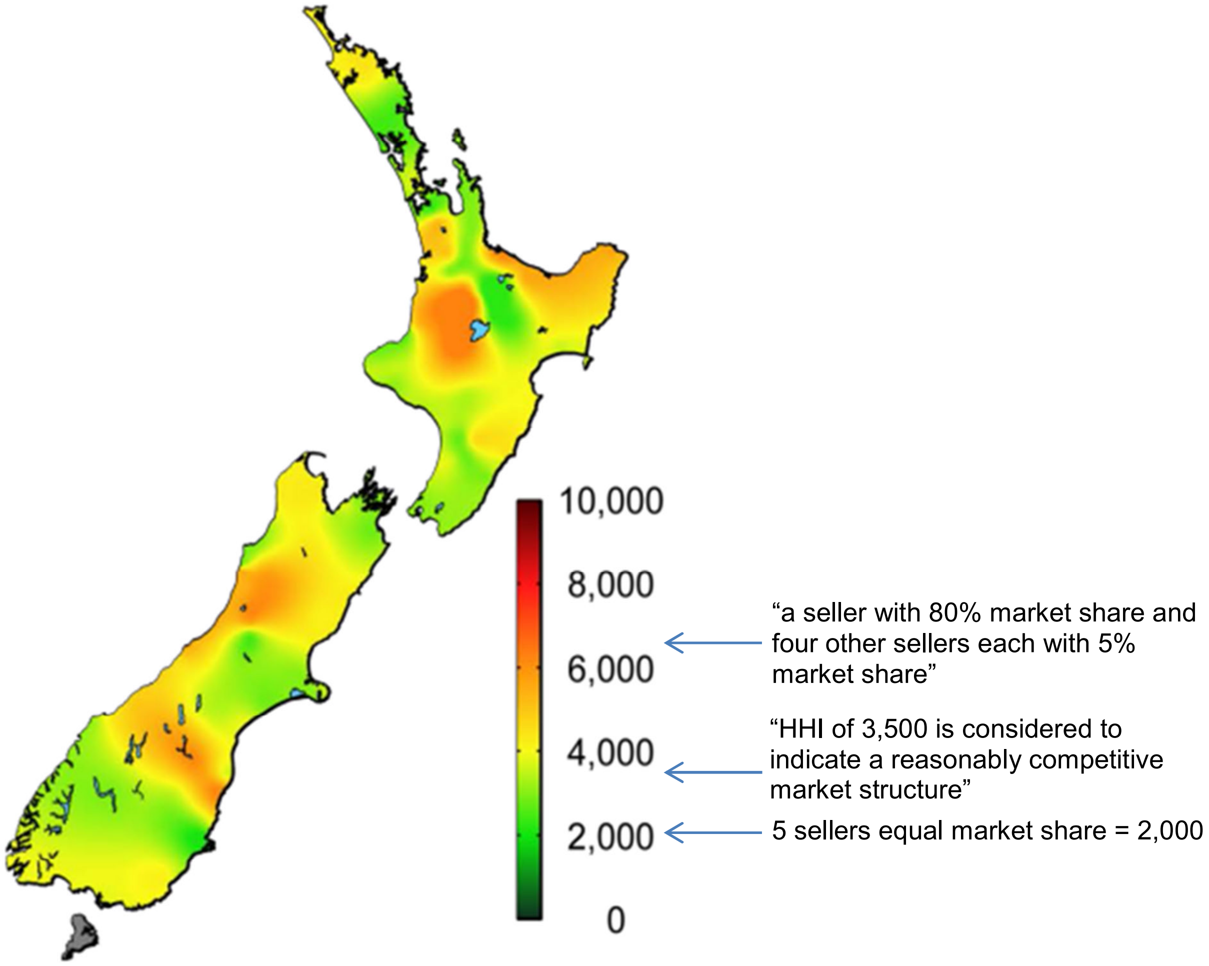
> *Depending on the facts at the time and the question at hand, the Commission has previously defined the related customer and geographic dimensions of the retail market in one of two ways:*

14 NZ Commerce Commission, Commerce Act 1986 s27, s30 and s36 Electricity Investigation, Investigation Report, 22 May 2009, p. 50, para. 195.

- *separate markets for the regional sale of electricity to domestic retail customers (including small commercial customers), and the national sale of electricity to large commercial / industrial customers that have individual contracts with electricity retailers; or*
- *a national market for retail customers, while noting that in some circumstances it may be appropriate to adopt narrower regional markets.*
  [emphasis added; footnotes omitted]

The Authority's own analysis of retail competition, including the calculations of the Hirschman Herfindahl Index (HHI) for each network area, also supports the notion of a regional retail electricity market. As is evident in the Authority's HHI Heat Map in Figure 2, there are significant differences in HHI across New Zealand, with much of the country failing to meet the "reasonably competitive" benchmark of 3,500. If the retail market was national then significant differences in HHI could not exist across different geographic areas.

Figure 2: Electricity Authority HHI "Heat Map", Dec 2012



Source: Chart from Carl Hansen, "Regulation of the NZ electricity market", Presentation to EMAN 410 Students, University of Otago, 19 July 2013. Text from Electricity Authority, "Information on the Market #9 - Big changes in regional retail markets since 2004", 13 March 2012. http://www.ea.govt.nz/industry/monitoring/i-on-the-market/number9/

7.3.1. Transmission Constraints Create Regional Retail Markets

The existence of regional retail electricity markets is, in most cases, due to the presence of transmission constraints. Transmission constraints create potentially significant price risks that retailers cannot hedge.

The only ways to manage exposure to the price spikes arising from transmission constraints are:

1. Enter into a price hedge arrangement with the generator on the same side of the constraint (i.e. in the constrained region). If this generator is also the incumbent retailer in the region it has no rational incentive to offer hedges at a price that is any less than the average expected wholesale price including constraints – this then only offers the entrant retailer the benefit of certainty, and does not provide any cost advantage;
2. Only contract with load that can be controlled when a price spike occurs, or that is willing to pay the wholesale price as a pass-through. Traditionally, this would limit the retailer to industrial customers. However, the advent of smart metering may enable additional control of residential load by retailers, and also provide greater opportunity for residential consumers to be aware of the effects of wholesale prices and voluntarily control their load accordingly; or
3. Accept the additional wholesale price risk and either adjust retail prices to compensate for that risk, i.e. increase retail prices, which may make the retailer uncompetitive, or adopt a low-cost business model.

Alternatively, the retailer can avoid the exposure by not even entering the retail market.

It is also noted that Financial Transmission Rights (FTRs) could, in theory, help mitigate price risk. Unfortunately, at this time the only FTRs are between Benmore (BEN) and Otahuhu (OTA), so are of limited value to an entity seeking price certainty in the far North, the West Coast of the South Island, the Upper South Island, or other constrained locations. While further regions will likely be added in future, the current design of the FTR market means that it is unlikely that constrained locations will receive significant benefit from FTRs.[15]

The effect of all of this is that retailing in constrained regions is less attractive, and transmission constraints have the effect of creating regional retail markets.

7.3.2. DG is a Solution to Transmission Constraints

As noted above, transmission constraints potentially result in regional retail electricity markets and reduced retail competition.

One solution is to upgrade the constrained transmission. However, this option is rarely cost-effective. The West Coast regularly experiences transmission constraints, but there appears to be little prospect of the capacity into the West Coast being upgraded.

15 See also the discussion in footnote 16 below.

A reasonable and viable alternative is for more DG to be built. Any DG with an element of storage can be used to reduce net demand during periods of constraint, thus reducing the severity of the constraint. A consequence of such DG will also be the ongoing deferral of the transmission upgrade – the very existence of the DG will mean that the transmission link will be kept at the current capacity (which may be regularly constrained) and not expanded unless there is a very significant increase in load that cannot be met by building further DG. DG is a very real competitor to transmission and in the more remote distribution networks will be used in place of expensive transmission upgrades.

7.3.3. Independent DG Mitigates Market Power in Regional Markets

Not only does DG obviate the need for local upgrades in transmission capacity, any generation located behind a constraint reduces the net load in the constrained region, making it less likely that constraints will occur in the first place. Furthermore, where the generation is owned by a party other than the incumbent retailer then it will have the effect of facilitating competition in the regional electricity market as all retailers will have the option of contracting with the generator.[16]

7.4. Environmental Benefits

We agree with the Working Paper's general conclusion that the ETS and other mechanisms exist to produce a price reflective of the externality resulting from greenhouse emissions, and there is no obvious compelling reason to favour DG over grid-connected generation for environmental benefits. On a project-by-project basis, however, there may be cases where DG provides enhanced environmental benefits over the same form of generation constructed on a large scale. For example, a small scale hydro dam may have less adverse effects on aquatic life and clearly results in less land being inundated; a small scale wind farm with 1-10 wind turbines can be situated in less visible areas with less (noise) impact on nearby populations; and in both examples the civil works are considerably less, producing less impact on the surrounding environment. These effects are addressed through the consenting process, which is a combination of political and evidence-based processes, and should be generally assumed (for the purpose of *this* consultation) to produce efficient outcomes (just as it is assumed that the ETS and other mechanisms related to greenhouse gases produce efficient outcomes).

7.5. Efficiency Benefits

The Authority presents a calculation of the productive efficiency loss that might arise if ACOT has the effect of causing some DG which is assumed to be low efficiency to generate ahead of grid-connected generation that is assumed to be more efficient.

The Authority does not, however, produce any evidence to support the contention that some (or any) DG is less productively efficient than grid-connected generation. Whether measured on a variable cost or marginal cost basis, where is the evidence that DG is less efficient?

16 It should be noted that a location-specific power-purchase agreement such as this is equivalent to the more complex arrangement of a price hedge and a location hedge (FTR). A fully functioning and integrated hedge market would allow these equivalent instruments to be traded at any location and for the resulting trades to adjust the prices of all other instruments (just as injection or offtake at one location in the physical system alters the price at all other locations). For now, however, the various markets remain separate, and the only true way to hedge in a potentially constrained region is to contract with local generation in that region. DG is often an important component of local generation.

As discussed in section 3.2, a focus on the long-term benefit of consumers means that the Authority should be focussed on dynamic efficiency rather than productive efficiency. The analysis presented in sections 5.5 and 6 of this paper demonstrates that DG can have significant dynamic efficiency benefits, particularly if there is a high level of DG. The Authority should focus on removing the impediments and countering the market failures that both constitute barriers to the development of further DG.

8. OTHER BENEFITS OF ACOT

There are numerous other benefits from ACOT payments that we haven't attempted to model but that should also be considered and quantified as part of the EA's assessment of DG benefits.

8.1. A Price Signal for Reliability at Peak

Wholesale electricity prices provide a general signal for generation, with higher prices at peak providing some degree of incentive to generate at market peak. Market peak may, however, differ from the peak on the local or regional network (such as the Upper and Lower North and South Islands). ACOT provides a price signal for providing reliable generation at these peaks: ACOT payments are only received if generating at the relevant peak. Without a response from DG, the only means of reducing peaks is via demand response including older, less reliable systems such as ripple control.

8.2. Reduction in Peak Wholesale Prices

To the extent that wholesale market peaks coincide with regional peaks, ACOT also has the effect of reducing peak wholesale prices. ACOT provides a stronger incentive than wholesale prices alone for DG to maximise generation during peak periods. This means that the net peak demand in the wholesale market is reduced, which in turn means that peak wholesale electricity prices are reduced and are more stable. Lower peak prices and lower volatility in those prices both feed through into lower retail prices for consumers, providing a benefit to consumers.

8.3. Cash Flow Benefits

We have established in the previous section that DG provides benefits, particularly competition benefits in the retail market and dynamic efficiency benefits over time.

In addition to directly providing DG with a price signal that reflects the value of reliability at peak and transmission displacement, ACOT also provides a valuable mechanism to reduce the volatility of cash flows earned by DG. This increases the possibility that investment will occur and the potential benefits will be achieved.

It is well accepted and non-controversial that if a risk-adjusted discount rate is applied, volatile cash flows have a lower present value than less volatile cash flows with the same mean value. Or, put another way, a mechanism that reduces the volatility of cash flows will increase the value of those cash flows. This is, fundamentally, the reason why hedging with futures and options can add value to a firm. The example below illustrates the concept of expected utility and its application to investment decisions. We then discuss the role of idiosyncratic cash flow volatility (i.e. volatility specific to the investment) and how that reduces investment. We then turn to the specific example of DG and the reduced hedging opportunities that appear to be available to DG.

8.3.1. Expected Utility Analysis

Table 4 below provides an example of how volatile cash flow affects the utility of an investor. A quadratic utility function is assumed, with utility given by:

$$U(C) = C - 0.025\ C^2$$

The quadratic utility function is a standard utility function utilised in financial economics to characterise a risk-averse investor, although other utility functions could equally well be used.

Table 4 shows three scenarios: (1) volatile cash flows; (2) partially hedged cash flows; and (3) a constant increment to cash flows. The Expected Utility shown in the last row of the table is the value that the investor obtains from each cash flow.

Table 4: Example of Cash Flow Volatility and with Quadratic Utility

Cash Flows (C)			
Period	**Volatile**	**Partially Hedged**	**Increment to Cash Flow**
1	1	2.6	1.2
2	7	6.2	7.2
3	5	5.0	5.2
4	2	3.2	2.2
5	10	8.0	10.2
Total	25	25	26
Average	5.0	5.0	5.2
Sample Variance	13.50	4.86	13.50
Sample SD	3.67	2.20	3.67
Coefficient of Variation	0.73	0.44	0.71
Utility Calculation: $U(C) = C - bC^2$, b = -0.025			
Period	**Volatile**	**Partially Hedged**	**Increment to Cash Flow**
1	0.975	2.431	1.164
2	5.775	5.239	5.904
3	4.375	4.375	4.524
4	1.900	2.944	2.079
5	7.500	6.400	7.599
Total Utility	20.525	21.389	21.270
Expected Utility	4.105	4.278	4.254

Cash flows in the first (volatile) and second (partially hedged) cases have the same average value (5.0), but the standard deviation is 3.67 for the volatile cash flows and 2.20 for the partially hedged cash flows. The second panel shows that the expected utility from the volatile cash flows is 4.105, while the expected utility from the partially hedged cash flows is 4.278. The reduction in volatility from hedging has increased the utility to the risk-averse investor, meaning that the risk-averse investor would be willing to pay more to own those cash flows.

The cash flow in the third case has been increased by an increment of 0.2 over the volatile cash flows in each period. The standard deviation remains at 3.67. The second panel shows that although the cash flows have the same level of volatility as measured by the standard deviation, the expected utility has increased from 4.105 to 4.254. Adding the constant increment to cash flows has again increased the utility to the risk-averse investor and that investor would be willing to pay more to own those cash flows.

8.3.2. Cash Flow Volatility Reduces Investment

We will take a moment to justify the statement that idiosyncratic risk is important. Expected utility analysis, which we present in this section, underlies modern portfolio theory.[17] Modern portfolio theory also underlies the Capital Asset Pricing Model (CAPM), which implies that it is only non-diversifiable risk that is important, since all other (idiosyncratic) risk can be diversified away by holding the market portfolio. Much observed data cannot be explained by the CAPM and considerable research effort is devoted to trying to explain observed anomalies.

It is also quite clear that, to paraphrase Markowitz, the well diversified investor, like a unicorn, does not exist. This is particularly true of the entrepreneur, who is heavily concentrated in one activity and is highly exposed to the idiosyncratic risk of that activity. It is also true of the larger firm, which is concentrated in a small set of activities and which has a Board of Directors legally bound to act in the best interests of the firm (which cannot be bankruptcy) and to protect the interests of creditors. While it may be acceptable in the context of a well-diversified portfolio for the firm to fail, or even to perform sufficiently poorly that access to credit markets is constrained, it is not an acceptable risk in the context of the interests of the entrepreneur, the firm, or creditors. Idiosyncratic risk is highly relevant to the consideration of whether an otherwise financially viable investment will proceed.

Even though company directors may be legally obliged to consider the interests of creditors, Gemmill and Keswani (2011) show that idiosyncratic risk factors are a significant determinant of credit spreads on corporate bonds.[18] Therefore, even amongst firms that are able to access credit markets, cost of capital is directly affected by idiosyncratic risk.

The literature demonstrates that cash flow volatility is negatively associated with investment. For example, Deshmukh and Vogt (2005) test the relationship between investment and cash flow volatility both for firms that hedge and firms that do not hedge.[19] They find that investment spending is less sensitive to cash flow for hedgers than for non-hedgers, and that among hedgers, investment spending is less sensitive to cash flow when the extent of hedging is higher. Minton and Schrand (1999) show that higher cash flow volatility is associated with lower average levels of investment in capital expenditures, R&D, and advertising.[20] They also find that cash flow volatility increases the costs of accessing capital markets. It is important to recognise that this effect is related to cash flow volatility for the individual firm, being an idiosyncratic rather than systematic risk. Applying these results to the example in Table 4, an investor would prefer to invest in either of the second and third cases than in the unhedged volatile cash flow.

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17 For a discussion, see Markowitz, Harry M. (1959) *Portfolio Selection: Efficient Diversification of Investments*, John Wiley & Sons: New York.

18 Gemmill, Gordon and Keswani, Aneel. (2011) "Downside risk and the size of credit spreads", *Journal of Banking & Finance*, Vol.35 (No.8):2021-2036.

19 Deshmukh, Sanjay and Stephen C. Vogt (2005) "Investment, cash flow, and corporate hedging", *Journal of Corporate Finance* 11:628–644.

20 Minton, Bernadette A. and Catherine Schrand (1999) "The impact of cash flow volatility on discretionary investment and the costs of debt and equity financing", *Journal of Financial Economics* 54:423-460.

8.3.3. Few Hedging Opportunities Available for DG

There are few hedging opportunities available to investors in DG. The primary markets are (i) the Over-The-Counter (OTC) market for Power Purchase Agreements (PPAs) and Contracts-for-Differences (CfDs), and (ii) the ASX futures and options market. While the ASX market has demonstrated considerable increase in volumes, the structure of that market is such that it is not realistically available to smaller firms. Furthermore, the success of the ASX market has had a commensurate dampening effect on the market for PPAs and CFDs.

Costly for Small Market Participants to Trade on a Futures and Options Exchange

The very nature of a futures and options exchange also presents barriers to participation by small independent retailers, generators, and industrial loads. An initial margin must be posted, and further margin calls may be made throughout the life of the contract. Positions are also limited to 200% of a participant's NTA backing.[21] The ASX cautions that participants are responsible for monitoring their exposures at all times.[22]

As a result, the electricity futures and options offered on the ASX are most readily available to the large firms that can access large cash reserves necessary for margin calls, and have the necessary resources (human and financial) to monitor the electricity market and the ASX hedge markets.

Large grid-connected generation is usually part of a large company that has significant cash reserves, and due to its size is able to efficiently access the financial markets. The government ownership of three of the large gentailers is also recognised by the credit rating agencies and results in access to lower cost funds.[23] This does not make the large grid-connected generation more efficient than DG, it is simply recognition that financial market frictions make it more difficult for smaller firms to access cash. The flow-on effect from this is that it is more difficult for small firms to access hedging markets.

ASX Futures are Below the LRMC of New Generation

Figure 3 below shows historical wholesale electricity prices, ASX futures prices, and the LRMC of new generation. Historical prices are load-weighted annual averages from the Centralised Data Set. ASX futures prices are quarterly; a dotted line shows the four-period average of those prices. The stepped dark brown line shows MBIE's estimate of future wholesale prices. Two estimates of LRMC are provided: the tan shaded band shows MBIE's estimate of LRMC

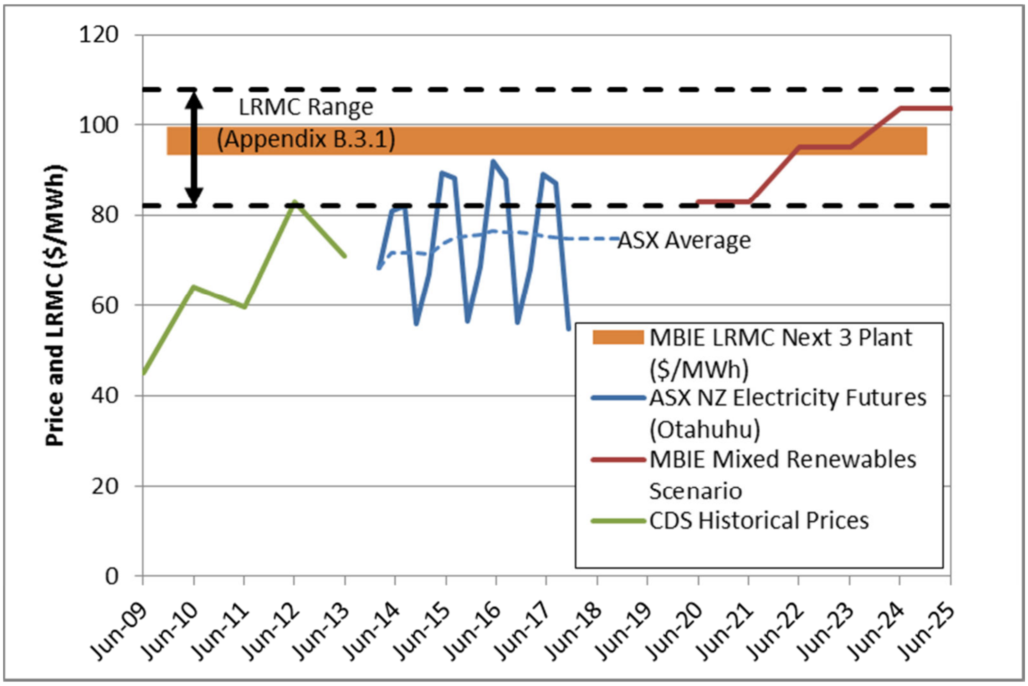
21 ASX, Margins and Capital Based Position Limits, http://www.asx.com.au/services/clearing/margins-capital-based-position-limits.htm , accessed 16 January 2013.

22 Op cit.

23 For example, Standard & Poor's explicitly adjusts the credit rating of a "Government Related Entity" based on the likelihood of Government support during periods of financial stress. That the New Zealand Government would support SOEs has been conclusively demonstrated by recent events surrounding Solid Energy. For New Zealand, Standard & Poor's has issued a sovereign credit rating of AA+ for local long-term credit and AA for foreign long-term credit. For a rating of AA+, and only a "moderate" likelihood of Government support, Standard & Poor's rating criteria increase the credit rating by one notch for all issuer credit ratings of A or less. Most importantly, sub-investment grade BBB is notched up to investment grade BBB+. Higher likelihood of Government support is associated with greater upgrades in credit rating. See Standard & Poor's "General Criteria: Rating Government-Related Entities: Methodology and Assumptions", 9 December 2010, reissued 28 March 2013.

for the next three most economic plant; the dashed black lines show the range of LRMC for the plant in Appendix B.3.1 that are economic.

Figure 3: ASX Futures and the LRMC of New Generation



Peak month prices on the ASX are sufficient to meet the LRMC of the least cost new generation options, but average prices are not. Possible explanations for the discrepancy between futures prices and LRMC are:

- market participants are expecting no new generation capacity to be required for the next four years;
- market participants are expecting and have priced in political intervention such as the NZ Power scheme; or
- the market is inefficient and does not reflect future expectations of all participants in the wholesale electricity market.

It is noted that there is little demand for long-dated futures; as at 27 January 2014 the last trade for all futures for 2017 had occurred in October or November 2013.[24] With infrequent trading (and consequentially low liquidity) it is highly likely that prices do not fully reflect current information or expectations.

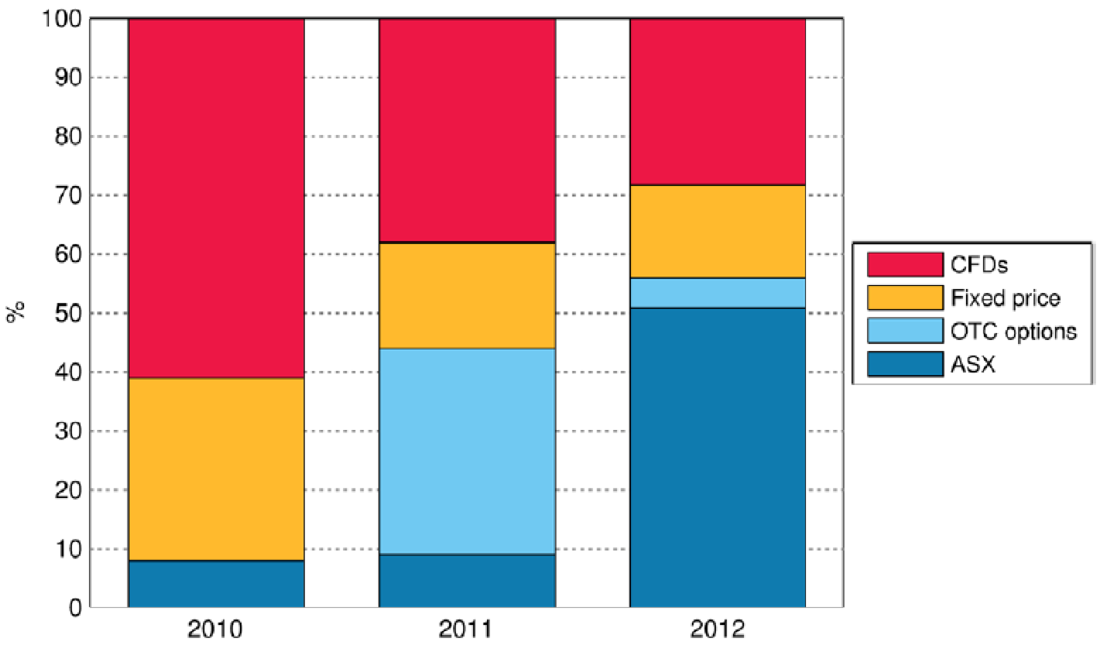
24 March 2017 futures last traded on 7 November 2013, June 2017 futures last traded on 27 November 2013, September 2017 futures last traded on 29 November 2013, and December 2017 futures last traded on 24 October 2013.

ASX Impact on PPA Market

Figure 4, prepared by the Electricity Authority, shows that hedges traded on the ASX grew from less than 10% of the hedge market in 2010 to 50% of the market in 2012. It is possible that purchaser appetite for long-term PPAs has reduced now that much shorter term instruments are available. Further, to the extent that purchasers benchmark proposed PPAs against ASX prices they will not be willing to pay the LRMC of a new plant. As a consequence of these factors, Pioneer Generation has observed that the success of the ASX hedging market has had the (presumably unintended) consequence of significantly reducing the market for PPAs.[25]

The development of the ASX hedge markets would appear to be a success: growing volumes improve liquidity, and the forward prices in theory become more meaningful. However, the very standardisation that in theory improves liquidity also increases price risk relative to a PPA. A PPA can be customised to a specific location, and it can be set for long periods of time. In an exchange-traded market for futures over *any* commodity it is difficult to obtain contracts for periods exceeding five years.

Figure 4: Composition of New Zealand Electricity Hedges, 2010-2012



Source: Electricity Authority, "Regulation of the NZ electricity market", Presentation to EMAN 410 Students, University of Otago, 19 July 2013.

25 Personal communication from Grant Smith, General Manager Business Development & Strategy, Pioneer Generation, 9 January 2014.

The success of the ASX futures and options has therefore had the effect of moving the cash flows from DG from the second (partially hedged) case to the first (unhedged) case. Even though the mean or expected value of the cash flows is the same, the value to the risk-averse investor is less (lower expected utility), and the literature demonstrates that investment is likely to be less.

8.3.4. The Role of ACOT

In the context of the example in Table 4, ACOT effectively moves the cash flows from DG from the first case (unhedged) to the third case (increment). ACOT both stabilises cash flows for DG (reduces relative volatility) and increases the expected value of cash flows. Both of these effects increase the value of any given DG investment and make it more likely that an economically beneficial DG investment will proceed.

From the perspective of its effect on cash flows and investment, ACOT should not necessarily be thought of as providing a benefit to DG that large grid-connected generation cannot access. Due to financial market frictions, the large grid-connected generators have access to financial markets that are effectively closed to smaller entities. Although it is not its primary function, ACOT has the beneficial effect of partially mitigating the market failure caused by these financial market frictions.

8.4. ACOT Prevents Market Failure

The most common cause of market failure is the presence of unpriced or unrewarded externalities. When negative externalities are generated by an activity then too much of that activity will occur if the externalities are unpriced. Similarly, when positive externalities are generated by an activity then too little of that activity will occur if the externalities are unrewarded. This is a standard and non-controversial result.

The dynamic efficiency analysis reported in Section 5.5 and Appendix B indicates that there are significant benefits to consumers from increased investment in embedded generation. To the extent that the DG investment may rely on compensation (via ACOT) for the externalities created, if the Authority intends to remove ACOT then it will be enforcing a market failure.

Much DG is financially viable given projected wholesale electricity prices; and DG that is not viable on the basis of energy production alone can yield net economic benefits by substituting for transmission. As discussed in section 8.3, even for financially viable DG, ACOT can provide the difference between investing and not investing in the project as it provides a potentially more certain and stable revenue stream. Removing ACOT will increase the risk that financially viable DG will not proceed, and ensure that sub-viable DG which would displace transmission investment will not proceed. This would eliminate the positive economic benefits reported in sections 5.5 and 6.

9. RESPONSES TO THE AUTHORITY'S CONCLUSIONS

Table 5 below sets out our response to each of the conclusions in the Working Paper.

Table 5: Responses to Conclusions in Working Paper

Authority Conclusion	Response
(a) Does not appear to be strong evidence indicating that DG location has been determined by avoidance of a transmission investment rather than access to a suitable site or resource. ACOT payment rates are largely identical across distribution networks. There is not a strong link between the ACOT payment and location of DG to either relieve congestion and/or provide an alternative to transmission.	Markets influence behaviour via price signals. The price signal for congestion relief provided by wholesale electricity prices is insufficient to provide investment signals for transmission, grid-connected generation, or DG. Interconnection charges could provide a locational investment signal, but they have been non-locational for a long period of time. Therefore, so long as the pass-through ratio is approximately the same across networks, ACOT payments would be expected to be approximately the same across networks, and the signal to investment would be independent of location. If a locational signal for DG is required, then the TPM should be amended to provide a locational signal to all load and generation.
(b) ACOT payments, and the existence of DG, appears to have no observed effect on transmission investments.	Transmission investment on the core grid is influenced by aggregate peak load across multiple distribution networks and regions. A smaller network may not be able to influence the location or timing of major upgrades, as load and generation on that network will be swamped by load on other networks such as Auckland. However: Even in Auckland projected load growth (predicted by Transpower) has not eventuated. This is at least in part due to micro DG such as PV. That the core grid upgrades received regulatory approval is a *regulatory* failure, not a failure on the part of DG to deliver benefits. Better questions than the one that the Authority is asking are whether PV and other micro DG receives sufficient recognition of the benefit it provides, and how the core grid upgrade received approval to proceed (i.e. investigate the regulatory failure). Many of the smaller networks have not had any significant upgrades in connection capacity for a long period of time. It should be investigated whether DG has contributed to this outcome.
(c) Although there appear to be some exceptions, ACOT payments have little observed effect on distribution investments or costs, and ACOT payments appear to provide no other material benefits to distributors	ACOT is the avoided cost of <u>transmission</u>, not the avoided cost of distribution. Schedule 6.4 of the Code allows for other avoided costs to be passed to DG operators, and there are clear examples of where this has occurred.

Authority Conclusion	Response
(d) A prevalence of DG on some distribution networks can cause net costs to the distributor	This is true, but irrelevant. Schedule 6.4 of the Code provides a mechanism for distributors to charge DG operators for these costs. There is clear evidence that distributors are implementing arrangements that set limits on injection where that would create a cost to the distributor. For example, Pioneer Generation is charged an excess demand charge of $5/kVAh by one distributorif import into one ICP containing DG exceeds a nominal maximum demand limit. It is also noted that in essence this is also no different to loads: a prevalence of load on a distribution network causes net costs to the distributor.
(e) The benefits of DG to distributors should increase as energy storage capability improves	This is true, but irrelevant. It has always been the case that a DG operator with storage (such as hydro) has been better able to respond to peaks, generating at times that the distributor would otherwise elect to operate ripple control or other forms of demand side management.
(f) ACOT payments do not appear to deliver any other material economic benefits.	ACOT payments are intended to reflect the long run cost of increments to transmission capacity; they are not intended to reflect anything else. As such, as a first order approximation, the conclusion is what should be expected. However, the analysis in this report identifies that there *are* additional benefits provided by ACOT. As noted in section 6, previous analysis by other parties identifies significant net benefits from DG penetration in distribution networks. As identified in section 7.3, and contrary to the Authority's conclusion, the Commerce Commission has generally identified that retail electricity markets for residential consumers are regional. The most common cause for regionalisation of retail markets is transmission constraints, and all generation, including DG, has an important role to play in improving competitive outcomes in a transmission-constrained area. As discussed in section 8.3 of this report, ACOT has an important role to play in mitigating market failures now that activity in the PPA market has significantly reduced and the ASX is not necessarily accessible to all market participants. ACOT helps to smooth the relative volatility of DG cash flows, making it more likely that financially viable DG will proceed.

Authority Conclusion	Response
(g) Given the Transpower interconnection charges are a cost recovery mechanism (to recover approximately $546 million for 2013/14), collectively, all connected consumers are paying both the full Transpower charge plus the full cost of the ACOT payments for a total cost of approximately $600 million. That is, the ACOT payments appear to have increased costs to consumers. ACOT is estimated to cost consumers $10 per household p.a.	The conclusion as stated relies on the assumption that the cause of the cost to consumers is ACOT rather than the failure of the economic regulation model for Transpower to expose Transpower to any form of demand-based risk. Given Transpower's historic cost valuation, revenue cap, and near certain recovery of investments, there should be little return to Transpower's shareholder over the risk-free rate of return. The identified "cost" associated with ACOT is a trade-off associated with the decision to allow Transpower a fixed revenue cap, and there is likely to be other costs. Those costs *should* be traded off against the overall lower risk to Transpower and lower revenue requirement, with the revenue cap only allowed if the benefits from the cap (lower cost of capital leading to lower revenue) exceed the costs of the cap (no demand signals to Transpower, reallocation of costs to consumers). Furthermore, to the extent that the identified problems are the result of regulated cost recovery for transmission, it is those mechanisms that should be looked at rather than interfering with the market for DG. It may be that the identified inefficiency is the cost of having a regulated cost recovery mechanism and must be born unless an even greater cost of little or no DG is to be incurred. This year the Commerce Commission will be consulting on the price-quality path for Transpower for the period 2015-2020, and that is the appropriate forum for addressing whether revenue cap regulation is appropriate, or whether Transpower should be exposed to some form of demand risk.

APPENDIX A: CURRICULUM VITAE

ANDREW SHELLEY

Consultant

MA (first class honours) Economics
Massey University

B.B.S. Information Systems
Massey University

Andrew Shelley is a regulatory economist with over 15 years' experience analysing complex economic and regulatory issues for energy-intensive, network and infrastructure industries. His recent work focuses on analysing the firm's response to regulation, including the impact of New Zealand's proposed emissions trading scheme on energy-intensive and emissions-intensive firms, and the impact of formal price control on utility revenues, cash flows, and investment.

Andrew has particular expertise in the electricity and telecommunications industries. He has advised on electricity transmission and distribution regulatory issues such as asset valuation, cost of capital, revenue requirements, pricing structure, and cash flow modelling. In addition to providing regulatory advice he has appeared as an expert witness in commercial arbitrations relating to New Zealand's electricity market, and developed expert evidence for a number of court cases. He has also advised firms in industries such as gas transmission and distribution, forestry, postal services, and rail networks.

Andrew's previous employment includes the positions of Principal at CRA International, Senior Consultant at PHB Hagler Bailly Asia Pacific Ltd, Costing & Economics Manager at Telecom New Zealand Ltd, and Strategic Analyst and Pricing Analyst at Transpower New Zealand Ltd. Mr Shelley is located in Wellington, New Zealand.

Andrew is a member of the New Zealand Institute of Directors and a member of the New Zealand Safety Council.

PROFESSIONAL HISTORY

2013 – **current**	President, Fly DC3 New Zealand Inc Director, Flight 2000 Ltd
2010 – **current**	Director, Aviation Safety Management Systems Ltd Senior Consultant, The Lantau Group
2008 – **current**	Director, Andrew Shelley Economic Consulting Ltd Senior Consultant, Oakley Greenwood Pty Ltd
2008 – 2010	Consultant, CRA International
2001 – 2008	Senior Associate, Associate Principal, and Principal, CRA International
1999 – 2000	Senior Consultant, PHB Hagler Bailly – Asia Pacific Ltd
1998 – 1999	Costing and Economics Manager, Network Group, Telecom New Zealand
1995 – 1998	Pricing Analyst and Strategic Analyst, Transmission Services, Transpower New Zealand Ltd
1995	Analyst Programmer, Foodstuffs (Wellington)
1993 – 1994	Study for Master of Arts
1990 – 1993	Analyst Programmer, Farmers' Mutual Insurance Group

Consulting Experience

Utility Price and Revenue Regulation

- Advising Vector Ltd on various aspects of pricing for electricity distribution and gas transmission and distribution.
- For Contact Energy, preparation of a report analysing whether the balance of Transpower's "economic value" (overs and unders) account was consistent with what would be expected in a workably competitive market.
- Advising Unison Networks Ltd in its responses to the New Zealand Commerce Commission's implementation of the price control provisions contained in the Commerce Amendment Act. This has included preparation of advice in respect of, and preparation of submissions and expert reports in response to the Commission's consultations on "Regulatory Provisions of the Commerce Act", "Input Methodologies", regulatory taxation, asset valuation, and cost allocation.
- For Energex distribution network (Brisbane), development of a cost-based pricing model for regulated distribution services. This project also included the provision of advice on pricing policy, particularly with regard to developing prices that reflected the impact of demand growth on capital expenditure. Delivery of the pricing model also included provision of a user guide, technical documentation, and user training.
- On behalf of Unison Networks Ltd, preparation of a submission in response to the New Zealand Commerce Commission's initial proposals for resetting the price path and quality thresholds in 2009.
- Advising Vector Ltd on economic issues arising from the New Zealand Commerce Commission's draft decisions on price control for gas distribution services.
- For the Electricity Networks Association, preparation of a submission to the New Zealand Electricity Commission on Transpower's proposed transmission pricing methodology, and on proposed changes to the Benchmark Transmission Agreements.
- Advising a New Zealand generator on the principles of utility revenue requirements.
- Advising a New Zealand utility on issues of cost allocation related to setting regulated prices.
- For Vector Ltd, a detailed financial analysis of the implications of placing Vector under formal price control.
- For a New Zealand electricity lines business, development of a financial model to assess the relative performance of all electricity lines businesses under the Commerce Commission's CPI-X price path vs formal "building block" revenue regulation.
- Preparation of a series of expert reports for Unison Networks Ltd in response to the New Zealand Commerce Commission's draft intention to declare control of Unison, and for use by Unison in its subsequent Administrative Settlement negotiations. This work included analysis of the cost of capital, cash flows, financial ratios, and capital expenditure under various price control scenarios, as well valuation issues.

- An assessment of the costs and benefits of Transpower being placed under formal price control.
- Advising NGC on the calculation of excess profits, including detailed consideration of the theoretical basis for calculating excess profits, arguments on the treatment of gains on sale and the appropriate treatment tax effects.
- Advising a major Asian utility on recent developments in the regulation of infrastructure industries in selected countries.
- Developing a comprehensive financial model for an Australian Distribution Network Service Provider to analyse how the firm's financial performance would respond to different forms of regulation and price and revenue controls.
- Development of a comprehensive simulation model to assess the impact of a wide range of potential regulatory changes on a major Asian utility.

Cost of Capital

- Advising Unison Networks Ltd in its responses to the Commerce Commission's implementation of the price control provisions contained in the Commerce Amendment Act 2008, including advice on the appropriate weighted average cost of capital (WACC) for electricity distribution.
- For the Economic Regulation Authority in Western Australia, providing advice on the WACC to apply to a regulated railway.
- Advising various energy sector clients on the cost of capital appropriate for investment in electricity generation in Australia, Hong Kong, Malaysia, and the Philippines.
- Advising Transpower on the appropriate discount rate for use in the Grid Investment Test.
- Advising an Australasian transmission network owner on the appropriate asset beta for its WACC calculation.
- For an Australian telecommunications operator, advising on the cost of capital and method of asset value annuitisation for a submission to the Australian Competition and Consumer Commission.
- Assessment of the WACC for various activities of a major Australasian telecommunications firm, with particular emphasis on the impact of the regulatory regime. This included a detailed review and critique of approaches to setting regulated rates of return for telecommunications firms in Australia, North America and the United Kingdom.

New Zealand Electricity Market and Transmission

- Advising two providers of DG in negotiations concerning prices with a distributor.
- Advising a New Zealand electricity retailer and generator on economic issues related to the Ministerial Inquiry into the Wholesale Electricity Market.
- For a New Zealand electricity lines business, providing expert testimony in a commercial contract arbitration on the relationship between transmission charges and embedded generation.
- Advising Transpower on the appropriate discount rate for use in the Grid Investment Test.

- For the Electricity Networks Association, preparation of a submission to the New Zealand Electricity Commission on Transpower's proposed transmission pricing methodology, and on proposed changes to the Benchmark Transmission Agreements.
- Advice on forecast prices in the New Zealand wholesale electricity market.
- For Meridian Energy, analysing the magnitude of the potential benefits that might arise from the Electricity Commission encouraging investment in transmission alternatives.
- For a New Zealand electricity generator, preparation of a report on the economic consequences of short notice extension of transmission outages.
- For a New Zealand electricity market participant, providing a review of the principles of electricity transmission pricing.
- Critique of Transpower's valuation and pricing for a small New Zealand electricity lines business. This work included a detailed revaluation of parts of the Transpower network based on an alternative engineering assessment of the required network assets.
- Development of "opportunity cost" valuations of the power generated by a hydro scheme. The valuations were based on the forecast cost of alternative generation schemes, and included the effects of potential carbon taxes or tradable emissions permits.

Other Projects

- For Pacific Steel, development of a financial model to assess the relative impact on competitiveness of the New Zealand Emissions Trading Scheme (NZETS) and proposals under Australia's Clean Energy Futures Plan (CEFP).
- For the Ministry for the Environment (MfE), quantifying the potential impact of the proposed New Zealand Emissions Trading Scheme on three energy-intensive businesses. This work included the development of spreadsheet-based financial models for each of the three businesses, including separate models for "manufacturing", "full import" and "importation of intermediate product".
- Advising the Inland Revenue Department on economic issues related to tax avoidance litigation.
- Provision of advice on the costs and benefits of converting plantation forestry to dairy farms, including valuation of the impacts on greenhouse gas emissions.
- Providing economic advice and analytical support to the New Zealand Commerce Commission in a Commerce Act s36 case.
- For the New Zealand Ministry of Health, collation and analysis of data on the operating costs of air ambulance services.
- Advising an Australian electricity generator on the market for renewable energy certificates (RECs).
- For the New Zealand Electricity Efficiency and Conservation Authority (EECA), quantifying the benefits of the direct use of natural gas.
- Assessment and valuation of strategic options (including sale and acquisition options) for a New Zealand electricity lines business.

- For an Australian electricity generator, developing a framework for the valuation of easements used by electricity networks, including a review of the regulatory approach to easement valuation.
- For Telecom NZ Ltd, contributing to a number of public submissions to the New Zealand Telecommunications Commissioner, with particular emphasis on incentive effects of regulatory proposals and dynamic efficiency, cost recovery, reasonable rate of return on capital, funding of telecommunications service obligations (TSOs), and accounting for intangible benefits when calculating the cost of TSOs.
- Providing advice on how to adjust for differences in wage rates, cost of capital, and factor intensities in an international benchmarking study.
- Valuation and assessment of a proposed long-term contract for rail transportation, including a review of the approaches to rail price regulation in Australia.
- Review of the process and rules for the New Zealand Government's 2GHz radio spectrum auction.

Selected Public Consulting Reports

Cost of Capital and Leverage, Final Report, Prepared for Unison Networks Ltd, 2 September 2010.

Rents, Regulatory Commitment and the Role of Long Term Contracts, Final Report, Prepared for Unison Networks Ltd, 19 August 2010.

Regulated Returns for Australian and New Zealand Electricity Distribution, Final Report, prepared for Unison Networks Ltd, 15 August 2010.

Balance of the EV Account for Transpower's HVDC Assets, Prepared for Contact Energy, 8 August 2010.

Comments on Cost Allocation and the Regulatory Asset Base, Prepared for Unison Networks Ltd, 15 March 2010.

Implementing the Deferred Tax Approach, letter to Unison Networks Ltd, 26 January 2010..

Input Methodologies: Economic Issues, Prepared for Unison Networks Ltd, 13 August 2009.

with Anna Kleymenova and Tim Giles, *WACC for TPI's Iron Ore Railway*, Prepared for Economic Regulation Authority, 11 June 2009.

with Mike Thomas, *Regulatory Provisions of the Commerce Act*, Prepared for Unison Networks Ltd, 16 February 2009.

with Jeremy Hornby and James Mellsop, *Response to Commerce Commission's Discussion Paper: Threshold Reset 2009*, Prepared for Unison Networks Ltd, February 2008.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Comments on Commission's Draft Decisions Paper on Supply of Gas Distribution Services*, Prepared for Vector Ltd, 29 November 2007.

with Jeremy Hornby and Michael Thomas, *Discount Rate for the Grid Investment Test*, Final Report, prepared for Transpower NZ Ltd, 29 March 2007.

with Erik Westergaard, *Consultation on the Proposed Transmission Pricing Methodology*, Final Report, prepared for Electricity Networks Association, 2 February 2007.

with Jeremy Hornby and James Mellsop, *The Costs and Benefits of Regulating Transpower*, Final Report, prepared for Transpower NZ Ltd, 27 February 2006.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Cross Submission on the Intention to Declare Control of Unison*, Final, Prepared For Unison Networks Limited, 21 December 2005.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Review of the Commerce Commission's Intention to Declare Control of Unison*, Final Report, Prepared For Unison Networks Limited, 28 October 2005.

with Michael Thomas, *Net Benefits of Transmission Alternatives*, Final, Prepared for Meridian Energy Limited, 22 July 2005.

APPENDIX B: DYNAMIC EFFICIENCY ANALYSIS

This appendix summarises the assumptions and calculations used for the dynamic efficiency analysis.

B.1 TRANSMISSION INVESTMENT COSTS

There are many ways that we could estimate the cost of transmission upgrades, including using the building block values in the now defunct ODV handbook. For the purpose of this analysis, an estimate is derived from the figures that Transpower published in 2008 for the upgrade of the Woodville-Mangamaire-Masterton A 110kV transmission line. These are "real world" cost estimates for a transmission line that might be considered roughly representative of many smaller regions.

The Transpower report presents cost estimates for:

- a modern-equivalent replacement of the existing line using Hyena ACSR/AC conductor with a Winter/Summer rating of 80.5/73 MVA; and
- a "preferred option" upgrading to a Nobelium AAC conductor with a Winter/Summer rating of 148/135 MVA.

Transpower's cost estimates are summarised in Table 6 and Table 7 below.

Table 6: Transpower Cost Estimates for Hyena ACSR/AC Replacement

	WDV-MGM	MGM-MST
Substation	305.8	527.6
Line	2,384.9	6,480.1
Property and Consenting	131.5	177.0
Total	2,822.2	7,184.7
Line Length (km)	26.4	56.5
Winter Rating (MVA)	73.0	73.0
Cost ($/km/MVA)	1,464.4	1,742.0

Source: Line Length and Rating, Table 2-2; Capital Costs, Table 4-6; Transpower, *Woodville–Mangamaire–Masterton A 110 kV Transmission Line: Attachment B - Technical Cost Report*, December 2008.

Table 7: Transpower Cost Estimates for Nobelium AAC Upgrade

	WDV-MGM	MGM-MST
Substation	305.8	527.6
Line	3,319.8	7,601.6
Property and Consenting	542.1	2,091.0
Total	4,167.7	10,220.2
Line Length (km)	26.4	56.5
Winter Rating (MVA)	148.0	148.0
Cost ($/km/MVA)	1,066.7	1,222.2

Source: Line Length and Rating, Table 2-2; Capital Costs, Table 4-6; Transpower, *Woodville–Mangamaire–Masterton A 110 kV Transmission Line: Attachment B - Technical Cost Report*, December 2008.

The Transpower report also estimates maintenance costs of $112,500 for the transmission options considered. For the purpose of the current analysis, we convert that to a rate of $9.17/km/MVA.[26]

Figure 4 in the Working Paper (p. 30) shows that rather than the standard assumed life of 50 years, transmission assets may have a life of up to 80 years. The Authority states (para 8.16) that:

> *"the investment decision for the bulk of the transmission system is largely historic and was made between 30 and 60 years ago."*

Given the figures in Table 6 and Table 7, and the observation above concerning transmission line lives, the assumptions for this model are:

Table 8: Assumed Values for Transmission Parameters

Parameter	Value	Sensitivities
Economic life of transmission assets	70 years	
Current age of transmission assets	35 years	
O&M Expenditure	$9.17/km/MVA	
Cost of transmission assets	$1,200/km/MVA	$900/km/MVA and $1,500/km/MVA
Current transmission capacity	146MVA	(double circuit Hyena ACSR/AC)
Upgrade capacity	148MVA	

B.2 Wholesale Electricity Price Path

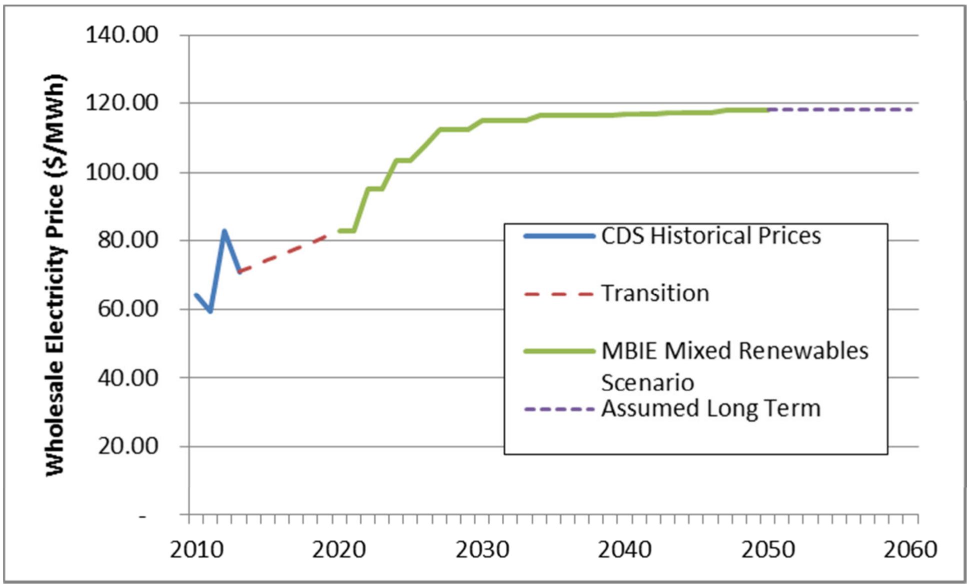
The wholesale electricity price path assumed for this analysis is the Mixed Renewables scenario from the latest Energy Outlook.[27]

The Mixed Renewables scenario provides wholesale prices from 2020 onwards. Prices in 2020 ($82.78/MWh) are almost identical to the actual load-weighted average wholesale prices in 2012 ($82.72/MWh). For the purpose of this analysis, average wholesale prices are assumed to follow a linear trend from 2013 ($71.08/MWh) to 2020. The resulting price path is shown in Figure 5 below.

26 $112,500 / 82.9km / 148 MVA = $9.17/km/MVA.

27 Ministry of Business Innovation & Employment, *Energy Outlook: Electricity Insights*, 27 June 2013.

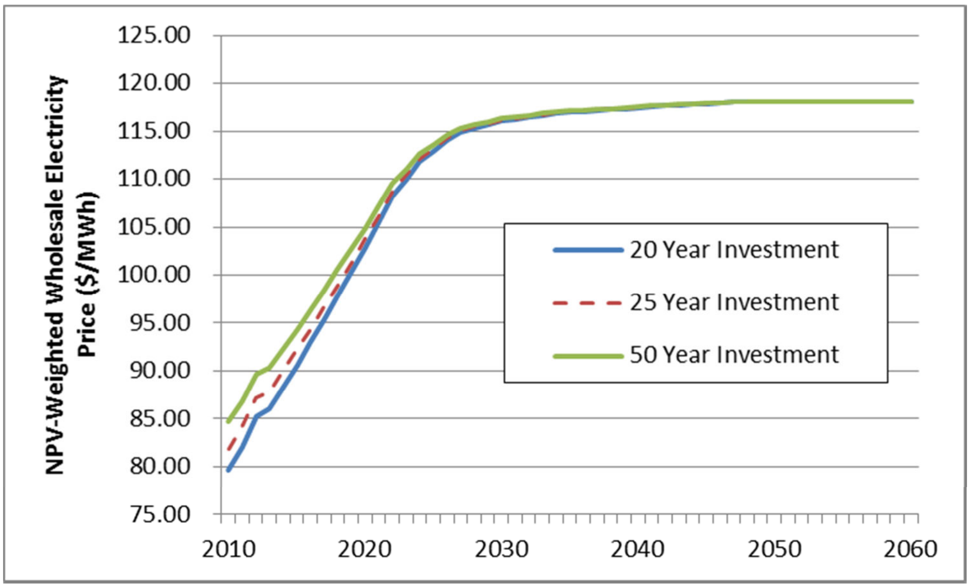
Figure 5: Assumed Wholesale Price Path based on MBIE Mixed Renewables Scenario



Source: CDS Historical Prices are load-weighted average prices from the Centralised Data Set; MBIE Mixed Renewables Scenario prices from Ministry of Business Innovation & Employment, *Energy Outlook: Electricity Insights*, 27 June 2013.

The wholesale price path can be converted to the NPV-weighted price that an investor in a generation plant would expect over the life of a generation investment. Figure 6 shows the NPV weighted prices for generation investments with a life of 20, 25, and 50 years. For an investment made in 2014, the NPV-weighted average price is $88.30/MWh for a 20 year investment, $90.05/MWh for a 25 year investment, and $92.36/MWh for a 50 year investment. The NPV is calculated using an investor discount rate of 10%. For investments made in later years the NPV-weighted prices begin to converge on the long run price of $118.03/MWh.

Figure 6: NPV-Weighted Average Wholesale Price for Investment



B.3 DG INVESTMENT COSTS

Establishing DG investment costs is a lot more difficult than establishing transmission investment costs. The relevant portion of capital costs is only that portion that is not recovered by the sale (or substitution for) generation at wholesale market prices.

This requires estimates of:

- Generator capital cost;
- Generator capacity factor (to calculate annual energy generated);
- Capacity factor at peak (to calculate peak avoidance);
- Generator operating costs;
- Average wholesale market price at time of generation (to calculate value of energy generated); and
- Proportion of load growth that is displaced by DG (to calculate the quantity of DG installed).

B.3.1 Generator Costs and Characteristics

To avoid biasing this analysis towards any particular project, the generator costs and characteristics used from a variety of readily available sources. The projects utilised are:

- A generic 2kW household wind turbine;
- Esk Valley Hydro, with data on capital cost, size, and capacity factor obtained from Trustpower press releases;
- Blackball Hydro, with data obtained from a detailed feasibility study published on the internet;[28]
- A generic Tier 1 wind farm of 1.5 MW; and
- Two "Break Even" wind plants, which have been calculated specifically to provide break even benefit values in this analysis. They do not necessarily represent any specific plant.

For wind projects the Peak Availability Factor is assumed to be the same as the Capacity Factor. Hydro projects such as Esk Valley Hydro are engineered to have additional machines and additional storage to ensure a high level of availability at peak. Accordingly, the Peak Availability Factor is estimated as 98%.

Table 9 overleaf summarises the characteristics of the assumed generation projects.

28 Keane Associates Ltd, *Blackball Hydro-Electric Power Scheme Feasibility Study*, 7 April 2009

Table 9: Assumed Distributed Generation Projects

Project	1kW-3kW wind turbine	Esk Valley Hydro	Blackball 0.43MW	Blackball 1.6MW	Generic Tier 1 Wind	Break Even Wind 1	Break Even Wind 2
DG Gross Capital Cost ($000)	20	13,500	5,080	6,450	5,400	4,112	4,172
DG Increment (MW)	0.002	3.8	0.43	1.6	1.5	1.5	1.5
DG Capacity Factor	25%	45%	60%	60%	42%	42%	42%
Peak Availability Factor	25%	98%	60%	60%	42%	42%	42%
Generator Life (years)	20	50	25	25	25	25	25
O&M ($/MWh)	16	5	5	5	16	16	16

B.3.2 Proportion of Load Growth Displaced by DG

The Authority's Working Paper notes (p. 30) that "the bulk of new DGs that have been installed … [is] often comparable to the rate of local annual demand growth". We assume that this means that, on average, new DG is equal in magnitude to load growth. We further assume that this statement refers to installed DG capacity rather than the DG that is available at peak times from that capacity. Given that most DG will not have 100% availability at peak this will mean that net load continues to grow slowly over time.

For the purpose of this analysis the following three broad scenarios have been assumed:

- No new DG;
- New DG capacity available at peak equal to 50% of load growth at peak; and
- New DG capacity available at peak equal to 100% of load growth at peak.

The first and second scenarios require transmission capacity to be upgraded when load reaches 95% of installed capacity. All scenarios require existing transmission to be replaced when it reaches the end of its economic life.

Gross peak load (i.e. before the deduction of new DG) is assumed to grow at 2% per annum.

B.4 Load Characteristics

The load characteristics for this model have been chosen to be broadly in line with the assumed existing transmission. Initial transmission capacity of 146MW is assumed (correlating to a double circuit 73MVA Hyena ACSR/AC conductor described above), and peak load is assumed to be 125MW. This allows for a number of years before a capacity upgrade is required, but still ensures that given reasonable load growth a transmission capacity upgrade will be required.

B.5 Discount Rate

This is not a calculation of the attractiveness of an investment, or the returns to a private investor: this is a calculation of the costs and benefits to society as a whole from the existence of DG. As such, a social discount rate is appropriate.

Shelley *et al* (2007) estimated a post-tax real discount rate for New Zealand of 3.5%, with a range of 2% to 6%.[29] This range incorporates both the "social rate of time preference" approach to the discount rate and the more conventional (from an investor's perspective) opportunity cost approach. Issues related to the social discount rate are also discussed by the NZIER, both in a general commentary[30] and in some project-specific analyses.[31] The NZIER concludes that the 8% real discount rate often used in New Zealand is too high.

The social opportunity cost reflects the rate at which individuals could borrow funds on an after-tax basis. Mortgage rates are currently at around 6.0%, and inflation is 1.4% with a longer term average of 2.7%. This provides a real interest rate of 3.2%-4.5% on an opportunity cost basis.

For the purpose of this analysis a post-tax real discount rate of 4% is selected, which is the mid-point of the range provided by Shelley *et al*, and lies within the range provided by current mortgage interest rates. Sensitivities are provided at 2%, 6%, and 8% post-tax real discount rates.

B.6 Summary of Assumptions

The assumptions used for the base case analysis are summarised in Table 10 below.

Table 10: Summary of Base Case Assumptions

Parameter	Value	Unit	Source
Initial Load	125	MW	assumption
Load Growth	2%	per annum	assumption
DG Example	Esk Valley Hydro		
DG Gross Capital Cost ($000)	13,500		Table 9
DG Gross Capital Cost	$3,553	per kW	calculated
DG Increment	3.8	MW	Table 9
DG Capacity Factor	45%		Table 9
Peak Availability Factor	98%		
Generator Life	50	years	Table 9

29 Andrew Shelley, Jeremy Hornby, and Michael Thomas, *Discount Rate for the Grid Investment Test*, CRA International, 29 March 2007, available online at http://www.ea.govt.nz/dmsdocument/3429.

30 Chris Parker, "Economics like there's no tomorrow", *NZIER Insights* 32, 2011.

31 Chris Parker, *Road maintenance taskforce economics*, NZIER, 6 February 2012

Parameter	Value	Unit	Source
O&M	5	$/MWh	Table 9
Investor Discount Rate	10%	pre-tax real	
PV Factor	9.91		calculated assuming annuity
Transmission Capacity	146	MW	Table 8
Economic Life of tx assets	70	years	Table 8
Current age of tx line	35	years	Table 8
Transmission Increment	148	MW	Hyena ACSR/AC @ 75°C, Winter Rating
Investment at	95%	of capacity	assumption
Transmission Line Length	50	km	assumption
Tx Capital Cost Rate	$1,200	$/km/MVA	Table 8
Tx Capital Cost	$60,000	$/MVA	calculated
Net Benefit Discount Rate	4%	Social Discount Rate, Real	

B.7 Calculation Methodology

The NPV of investment under each scenario is calculated as the sum of the NPV of transmission investment and the NPV of DG investment that cannot be justified by wholesale electricity prices.

It is assumed that generation that can be justified by wholesale electricity prices is economic in its own right. It is only that portion of generation capacity that cannot be justified solely by wholesale electricity prices that is potentially inefficient.

Given the selected generation technology, an investment occurs when the increase in demand is sufficient to justify an increment in capacity given the selected scenario. The gross capital investment associated with the DG investment is given in Table 9.

The present value expected from wholesale market revenues less operating and maintenance costs is calculated from:

- The NPV-weighted wholesale prices from Figure 6;
- Operating and Maintenance costs from Table 9; and
- An *investor* pre-tax real cost of capital of 10%.

The result of this calculation is the present value *to the investor* of energy revenues. If this present value is less than the capital cost then, setting aside the cash flow volatility issues discussed in section 8.3, the rational investor requires an additional payment. The amount of this additional payment is the amount that should be compared with transmission investment.

An example of these calculations are shown in Table 11 overleaf, which shows the first 10 years for scenario 3 (DG growth equal to 100% of load growth) for the base case assumptions. The first increment in DG capacity occurs in year 2. As per the figures in Table 9, incremental capacity is 3.8MW and the cost of that capacity is $13.5m. The present value to the investor of energy revenues (net of O&M costs) is $13.271m, a shortfall of $229,000. The $229,000 is the excess cost of the DG capacity and is included in the calculation of the present value of capacity investment costs. Transmission costs are $67,000 per annum, being the O&M costs on the existing transmission assets.

Table 11: Example DG Investment in Scenario 3, Years 0-10

Year	Gross Load	NPV Weighted Energy Price over 50 Years	NPV Weighted Energy Price less O&M	Aggregate DG Capacity	DG at Peak	Net Load	Transmission	Incremental DG Capacity	DG Gross Capital Investment	PV Energy Revenues less Generator O&M	DG Net Capital Investment	Transmission Capex and Opex
	(MW)	($/MWh)	($/MWh)	(MW)	(MW)	(MW)	(MW)	(MW)	($000)	($000)	($000)	($000)
0	125	90.38	85.38	-	-	125.0	146		$0	$0	$0	$67
1	127	92.36	87.36	-	-	126.9	146	-	$0	$0	$0	$67
2	129	94.36	89.36	3.8	3.7	125.1	146	3.8	$13,500	$13,271	$229	$67
3	131	96.39	91.39	7.6	7.4	123.3	146	3.8	$13,500	$13,573	$0	$67
4	133	98.45	93.45	7.6	7.4	125.2	146	-	$0	$0	$0	$67
5	135	100.55	95.55	11.4	11.2	123.5	146	3.8	$13,500	$14,192	$0	$67
6	137	102.70	97.70	11.4	11.2	125.5	146	-	$0	$0	$0	$67
7	139	104.89	99.89	15.2	14.9	123.8	146	3.8	$13,500	$14,836	$0	$67
8	141	107.13	102.13	15.2	14.9	125.9	146	-	$0	$0	$0	$67
9	143	109.60	104.60	19.0	18.6	124.3	146	3.8	$13,500	$15,535	$0	$67
10	145	111.06	106.06	19.0	18.6	126.4	146	-	$0	$0	$0	$67

B.8 NET BENEFIT FROM DG DISPLACING TRANSMISSION

Table 3 summarises the results of the analysis for the base case across the three scenarios. As shown in that table, dynamic efficiency benefits from DG displacing transmission are estimated at $1.9m to $7.3m for a small load centre of 125MW.

Table 12: Summary of Results

Scenario Description	Present Value ($000)			
	Distributed Generation	Transmission	Total	Benefit vs Scenario 1
Scenario 1: No DG	$0	$11,130	$11,130	$0
Scenario 2: DG growth equal to 50% of load growth	$0	$9,262	$9,262	$1,867
Scenario 3: DG growth equal to 100% of load growth	$204	$3,582	$3,785	$7,345

Transmission investment occurs in all scenarios; the investment that occurs in scenario 3 is solely the replacement of the transmission line when it reaches the end of its economic life. The investment in scenario 1 and scenario 2 also includes the investment in increased transmission capacity necessary to accommodate load growth.

B.9 SENSITIVITY ANALYSIS

Sensitivity analyses were conducted for the following parameters:

- Discount rates of 2%, 6%, and 8%;
- Different DG options;
- Transmission line length 25km and 100km; and
- Transmission line cost $900/MVA/km and $1,500/MVA/km.

The results of the sensitivity analysis are presented in Table 13 below. The table includes a calculation of the elasticity of the change in net benefit with respect to the change in the variable of interest. Benefits are directly proportion to transmission line length, i.e. doubling or halving transmission line length will double or halve the corresponding net benefits. Elasticity with respect to transmission (capital) line cost is in the range 0.8-0.9, so a given change in transmission line capital cost will induce a less than proportional change in net benefit. The reason for this is that a portion of transmission costs is O&M costs on existing assets, and that remains constant even when capital costs change.

The elasticities for the sensitivity to discount rates are as follows:

- Under scenario 2, the net benefit increases with a change in discount rate (elasticity is positive) but the proportional change in net benefit is less than the proportional change in discount rate (elasticity is less than one). Elasticity values depend on the discount rate.
- Under scenario 3, the net benefit changes in the opposite direction to the change in discount rate, i.e. an increase in the discount rate results in a reduction in net benefit.

The elasticities for the sensitivity to the DG option chosen can be very large. Net Benefits can change significantly (including to a large net cost) depending on the generation project. What this really indicates is that DG that is financially viable or nearly financially viable will provide net economic benefits, but DG that is not close to being financially viable does not deliver net economic benefits.

Table 13: Sensitivity Analysis

Variables					Net Benefit ($000)		% Change in Variable	% Change in Net Benefit		Elasticity	
Discount Rate	DG Example Project	DG Capital Cost ($/kW)	Tx Line Length (km)	Tx Capital Cost Rate ($/km/MVA)	Scenario 2	Scenario 3		Scenario 2	Scenario 3	Scenario 2	Scenario 3
Base Scenario											
4%	Esk Valley Hydro	$3,553	50	$1,200	$1,867	$7,345					
Vary Discount Rate											
2%	Esk Valley Hydro	$3,553	50	$1,200	$1,363	$9,081	-50.0%	-27.0%	23.6%	0.54	-0.47
6%	Esk Valley Hydro	$3,553	50	$1,200	$2,118	$6,073	50.0%	13.4%	-17.3%	0.27	-0.35
8%	Esk Valley Hydro	$3,553	50	$1,200	$2,204	$5,094	100.0%	18.1%	-30.6%	0.18	-0.31
Vary DG Example											
4%	1kW-3kW wind turbine	$10,000	50	$1,200	-$277,517	-$554,768	181.5%	-14962%	-7653%	-82.44	-42.17
4%	Blackball 0.43MW	$11,814	50	$1,200	-$209,624	-$418,149	232.5%	-11326%	-5793%	-48.71	-24.91
4%	Blackball 1.6MW	$4,031	50	$1,200	$863	$2,523	13.5%	-54%	-66%	-3.99	-4.87
4%	Generic Tier 1 Wind	$3,600	50	$1,200	-$11,073	-$21,774	1.3%	-693%	-396%	-519.78	-297.35
4%	Break Even Wind 1	$2,741	50	$1,200	$0	$276	-22.8%	-100%	-96%	4.38	4.21
4%	Break Even Wind 2	$2,781	50	$1,200	-$156	$0	-21.7%	-108%	-100%	4.99	4.61
Vary Transmission Line Length											
4%	Esk Valley Hydro	$3,553	25	$1,200	$934	$3,570	-50.0%	-50.0%	-51.4%	1.00	1.03
4%	Esk Valley Hydro	$3,553	100	$1,200	$3,735	$14,893	100.0%	100.0%	102.8%	1.00	1.03
Vary Transmission Cost											
4%	Esk Valley Hydro	$3,553	50	$900	$1,478	$5,722	-25.0%	-20.9%	-22.1%	0.83	0.88
4%	Esk Valley Hydro	$3,553	50	$1,500	$2,257	$8,967	25.0%	20.9%	22.1%	0.83	0.88