



# **Economic Review of Distributed Generation Pricing Principles Consultation Paper**

*A Report for Transpower*

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## Abbreviations

Term	Definition
ACOT	Avoided Costs of Transmission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Axiom	Axiom Economics
Code	<i>Electricity Industry Participation Code 2010</i>
Commission	Commerce Commission
DG	Distributed Generator
EA	Electricity Authority
EDB	Electricity Distribution Business
ESC	Essential Services Commission of Victoria
LNI	Lower North Island
LRMC	Long Run Marginal Cost
LSI	Lower South Island
NPV	Net Present Value
RCPD	Regional Coincident Peak Demand
Schedule 6.4	Schedule 6.4 of the <i>Electricity Industry Participation Code 2010</i>
SRMC	Short Run Marginal Cost
TPM	Transmission Pricing Methodology
UNI	Upper North Island
USI	Upper South Island



## Executive summary

This report has been prepared by Axiom Economics (Axiom) on behalf of Transpower. Its purpose is to assist Transpower as it evaluates the Electricity Authority's (EA's) proposed revisions to the distributed generation pricing principles contained in Schedule 6.4 of the *Electricity Industry Participation Code 2010* (the Code) as set out in its Consultation Paper.<sup>1</sup>

### Assessment of the status quo

The Consultation Paper highlights some key problems with the way in which many EDBs have compensated distributed generators (DGs) under the current Code provisions. On balance, we agree that there is a reasonable basis to conclude that the pricing arrangements for distributed generation, when combined with the current TPM, have resulted in inefficient outcomes. Most notably, this is strong reason to think that:

- DGs would have received payment from EDBs when there had been no reduction in either transmission or distribution network costs, i.e., reductions in RCPD would often not have been synonymous with network cost savings; and
- the ACOT payments made to DGs under the current arrangements have exceeded – perhaps significantly – any network cost savings, resulting in higher prices for final electricity consumers, overall.

However, it is important to recognise that this does not reflect a problem with the *pricing principles for distributed generation, per se*. Rather, it largely reflects a shortcoming in the price signal being provided by the RCPD-based interconnection charge *in the TPM*. As we explain in our report<sup>2</sup> in response to the EA's second Issues Paper on the TPM, much of the present inefficiency stems from the fact that the RCPD-based signal is *too strong*, and causing inefficient demand curtailment.

This particular issue therefore does not necessarily need to be addressed by removing Schedule 6.4. It could instead be assuaged by modifying the TPM. For the reasons set out at length in that report, we do not agree that the proposed 'area of benefit ('AoB')' charge would be an effective means of dealing with the above issue, since it would introduce myriad inefficiencies.<sup>3</sup> However, it could be addressed by other means, such as:

- retaining the RCPD-based charge, but temporarily weakening the price signal by increasing the number of periods over which contributions to RCPD are measured, e.g., to 1,000 or 5,000; or

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<sup>1</sup> Electricity Authority, Review of distributed generation pricing principles, Consultation Paper, 17 May 2016 (hereafter: 'Consultation Paper').

<sup>2</sup> See: Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper, A Report for Transpower*, July 2016 (hereafter: 'TPM report').

<sup>3</sup> See: TPM report, §3, 4 and 5.



- replacing the RCPD charge with a long-run marginal cost (LRMC) charge that provided an explicit signal to load and, potentially, generation customers of Transpower's forward-looking costs.

Leaving schedule 6.4 in place and simply reforming the TPM would not, however, address the second significant problem with the existing pricing arrangements – those arising from the lack of technology neutrality; namely:

- ACOT payments are available to DGs, but not to transmission-connected generators or other types of non-network solution (e.g., forms of demand management) that, in some cases, may deliver greater market benefits; and
- the provision of this additional revenue stream to DGs relative to other types of non-network solutions risks distorting investment decisions, leading to prices that are higher than they would otherwise be, over the longer-term.

Overall, in our view, the Consultation Paper is right to conclude that the pricing arrangements for distributed generation have resulted in efficient outcomes, *when combined with the current TPM*. However, the problems arising under the status quo are overstated because, in many cases, they relate to the transmission pricing arrangements rather than the principles in schedule 6.4.

## Assessment of proposed reform

On its face, the proposal would appear to address perhaps the two biggest problems with the current arrangement that we described above; namely:

- there would be fewer instances of DGs receiving payments from networks when they are not delivering (or would not deliver) network cost savings; and
- the proposed reforms would remove the artificial advantage to DGs granted by existing ACOT payments which, all other things being equal (see below), would serve to make the arrangements more 'technology neutral'.

However, there are a number of factors that would also need to be considered before it could safely be concluded that the proposal would deliver net benefits. First, as we have already seen, the first category of benefits is not unique to the proposal, since:

- adjusting the price signals in the TPM could also reduce the problem of DGs receiving payments when there has been no transmission cost saving; and
- this may be a more effective way of dealing with this matter than by removing the pricing principles in schedule 6.4 in their entirety.

Second, if the proposal is implemented, it might result in more instances of DGs *not* receiving payments from networks that reflect the value of the net cost savings they can deliver. We say this because:



- there is a number of practical reasons why network businesses may understandably tend to favour network solutions over non-network solutions – especially in the context of smaller capital projects; and
- in Australia, most if not all investments by networks in non-network solutions have arisen when they have been required to explicitly consider such options as part of formal regulatory investment test processes, whereas, in New Zealand:
  - Transpower is only required to give explicit consideration to non-network options when the estimated cost of the outlay is more than NZ\$20m (versus the A\$6m Australian threshold); and
  - there are no such requirements *at all* for EDBs, i.e., they do not need to undertake a cost benefit analysis of different options when investments are expected to exceed a certain threshold.

Third, the overall effect on the level of technology neutrality is more complex than implied in the Consultation Paper – and not necessarily positive. The incentives that investors would have to invest in distributed and transmission-connected generation, or other non-network options would also depend upon the relative impacts of:

- any contribution that EDBs require DGs to make to the common costs of their distribution networks – currently, the Code limits those charges to incremental costs, which prevents such an allocation; and
- any interconnection costs that transmission-connected generators would be required to pay under any reforms to the TPM – these could be considerable under the proposed ‘area of benefit’ charge.

Fourth, the reforms might be seen as unpredictable and inconsistent with the legitimate expectations of investors, which may reduce confidence in the regime. The Consultation Paper’s assertion that investors should have known that ACOT payments would not last is not persuasive, because:

- it rests on an unrealistic assumption that investors would know when those payments represented ‘cost reductions’ as opposed to ‘windfall gains’, when that is highly unlikely to reflect how investors actually think; and
- even if investors were at least cognisant of this distinction, it is arguably oversimplistic to suggest that they would naturally conclude that ACOT payments would not be sustained.<sup>4</sup>

It is also likely that some existing DGs who have provided network support in the past – or are doing so today – would not be fully compensated for delivering those benefits, i.e., that they would be ‘held up’. This is because the only practicable way

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<sup>4</sup> For example, there is generally no ‘unambiguously best’ way to set regulatory prices – trade-offs often need to be made, requiring judgement. The existence of some ostensible inefficiencies in a pricing methodology is not, therefore, a reason to put no stock whatsoever in the status quo.





for networks to contract with those parties is to ask: “if I do not make a network support payment, would my costs go up?”. However, this would mean that:

- some existing DGs would be providing network support but, because those generation investments are ‘sunk’, the networks would know that they do not have to pay anything to continue to receive those benefits; and
- some existing DGs would not be providing network support benefits now, but they may have done so in the past and not been fully compensated through the ACOT payments they have received hitherto.

Even if networks were inclined to procure network support services from these DGs, in the absence of any constraining regulatory pricing principles, they would be able to exercise unconstrained monopsony buying power. When dealing with smaller DGs in particular, they would most likely be able to procure network support at prices that represent only a fraction of their value. This is because networks would only have to pay the DG a price marginally above the incremental cost of providing the service, which may be much less than the marginal benefit.

Whether the factors set out above undermine investor confidence and certainty in practice hinges to a significant degree upon the extent that ACOT payments formed a key factor in existing DG’s decision making. If they did not – e.g., because the investments in question were made before the existing pricing principles were in place – then any economic costs arising from ‘hold up’ would diminish. However, the problems arising from substantial market power would remain.

In our opinion, the Consultation Paper does not include a sufficiently thorough consideration of the matters set out above. For example, the quantitative cost-benefit analysis (CBA) does not properly account for these factors and is also driven by a large number of unsubstantiated assumptions. The Consultation Paper therefore does not provide a robust indication of the respective costs and benefits of the proposal, relative to the status quo.

There would consequently be a high risk of unintended consequences if the reforms were implemented as proposed. In our view, given that any reform to the TPM would have a potentially large bearing on the benefits and costs of reforming the pricing principles for DGs, it would be better to eschew from making any decisions on the latter, until a position has been reached on the former.

## **Practical challenges for Transpower**

If Transpower was to undertake the broader contracting role envisaged in the Consultation Paper, it would face higher administrative costs. This is because it would find itself transacting with a larger number of DGs that would otherwise have dealt directly with their EDB to obtain an ACOT payment. This would give rise to a number of practical challenges. The first would be how to engage with existing DGs. As noted earlier, the only practicable way for Transpower to do so would be to:



- consider whether its network costs would increase if a payment was not made to an existing DG that has 'sunk costs', i.e., to apply a 'with or without a network support payment' test; and
- although this would result in some existing DGs being 'held up' (see above), the extent of those costs would depend upon whether their investment and operational decisions had hinged upon those ACOT payments.<sup>5</sup>

In deciding how to go about contracting with DGs – both existing or new – Transpower would also have to consider whether it would do so on a pure 'case-by-case' basis, or whether it might endeavour to set out some price and/or non-price terms in advance. Each approach offers advantages and disadvantages, and it may even be feasible for Transpower to implement elements of both. For example:

- a 'case-by-case' approach would be likely to produce relatively efficient outcomes if it is applied to 'larger' DGs with countervailing bargaining power, e.g., those bigger than, say, 5MW; whereas
- for smaller DGs, it may be worthwhile defining some up-front criteria that would determine when a DG was eligible for a payment – and the size of that payment – without having to enter into a bespoke contract.<sup>6</sup>

Finally, the proposed reforms may test the existing planning and investment frameworks for transmission. In particular, proponents of distributed generation projects may take a greater interest in the location of future network constraints – something that has not been vital to the receipt of ACOT payments in the past. An important question for Transpower is therefore whether the information currently available in its planning documents would be adequate for this purpose.

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<sup>5</sup> If they did not – e.g., because investments were made before the status quo was in place – then those costs may be trivial, or zero.

<sup>6</sup> We have assumed here that Transpower would not seek to exercise its substantial market power when dealing with smaller DGs which, for the reasons set out above, it could if it was so inclined. Instead, we have tried to set out an approach that, if implemented, might obviate the need for explicit regulatory pricing principles.



## 1. Introduction

This report has been prepared by Axiom Economics (Axiom) on behalf of Transpower. Its purpose is to assist Transpower as it evaluates the Electricity Authority's (EA's) proposed revisions to the distributed generation pricing principles contained in Schedule 6.4 of the *Electricity Industry Participation Code 2010* (the Code) as set out in its Consultation Paper.<sup>7</sup>

If the proposals set out in these papers are implemented they would have significant ramifications for Transpower's business. It has consequently asked Axiom to provide an independent economic review of whether the recommendations contained within the Consultation Paper are analytically robust and what some of the practical implications would be for its operations. We provide this in the remainder of this report, which is structured as follows:

- **section two** provides an overview of the many forms that distributed generation can take in practice and the effects it may have on the design and operation of electricity systems – both positive and negative;
- **section three** describes a number of key attributes that any reform to the distributed pricing principles should ideally strive to exhibit in order to promote efficient outcomes;
- **section four** assesses the status quo against those overarching objectives and explains why there is a reasonable basis to conclude that the current arrangements could result in inefficiency – especially under the current transmission pricing methodology (TPM);
- **section five** evaluates the proposed reforms against the same overarching objectives and highlights areas that may represent improvements and several other aspects that may require additional consideration; and
- **section six** highlights some of the more detailed practical challenges that are likely to face Transpower if it took on the broader role in the procurement of distributed generation envisaged under the proposed reforms.

Appendix A provides more detail on the regulatory arrangements applied to electricity transmission and distribution businesses in New Zealand and Australia, and the various ways in which those regimes seek to incentivise efficient investment in and use of non-network solutions, such as distributed generation. There are key differences between the arrangements which, as we explain in the body of the report, may be relevant to the reform proposed in the Consultation Paper.

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<sup>7</sup> Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016 (hereafter: 'Consultation Paper').



## 2. Background

Recognising the central role that distributed generation plays in the Consultation Paper, this section provides an overview of the many different forms it can take in practice and the impacts it can have upon the design and operation of electricity systems – both good and bad.

### 2.1 Types of distributed generation

To be considered a DG, a plant only has to be connected to an electricity distribution network rather than the high voltage transmission network (a special exception exists for ‘notionally’ embedded generators<sup>8</sup>). Although there are many different types of generator that conform to this broad definition, they can vary enormously in terms of their:

- **Fuel source:** some DGs will be powered by renewable fuel sources such as wind, water and sunlight; whereas others will be powered by natural gas or diesel.
- **Installed capacity:** DGs can vary substantially in size from a small rooftop solar photovoltaic (PV) system with a capacity of around 1kW to facilities that are many magnitudes bigger, such as:
  - large wind-farms and commercial power stations; and
  - diesel generators and gas-fired co- and tri-generation plants located in the basements of commercial buildings.
- **Availability:** some forms of distributed generation can be reliably called upon to supply a fixed amount of capacity for a set period (for example, diesel- or gas-fired or hydro generators can usually be switched on at any time<sup>9</sup>), whereas other sources (such as wind and solar) exhibit two elements of intermittency:<sup>10</sup>
  - their output can be quite variable – for example, the production of solar generation can be affected by cloud cover while the output of wind generation is affected by the strength of prevailing winds; and
  - their generation output can be difficult to predict – because they are influenced by the elements, there is no guarantee that a particular solar or wind generator will be available at any particular time.

*There is huge variation in the types of distributed generation.*

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<sup>8</sup> A ‘notionally’ embedded generator is connected to the transmission network, but is treated *as if* it was connected to the distribution network, i.e., as if it was a DG. This occurs when a generator has an inefficient incentive to connect to the distribution network, when it would be better for all concerned if it connected to the transmission grid. In these circumstances, Transpower may be able to offer the generator a ‘prudent discount’ whereby it pays a charge equivalent to that which it would have faced had it connected to the distribution network, even though it is connected to the transmission network, i.e., it is ‘notionally’ embedded.

<sup>9</sup> Provided, of course, that there is sufficient fuel available. This is most often a problem for hydro generators, e.g., if there is not enough water in storage lakes due to low rainfall.

<sup>10</sup> Note that electricity storage (such as batteries) can be used to mitigate the intermittency of renewable energy, allowing it to be used or exported at other times.



- **On-site usage:** the proportion of electricity generated that is injected into the distribution network can vary considerably between different types of DGs:
  - some DGs will have some or all of the electricity that they generate consumed on-site and only export the balance – small-scale household solar PV systems being an obvious example; whereas
  - other types of DGs, such as large scale wind-farms and commercial generators, will export nearly all of the power they generate into the distribution grid.<sup>11</sup>

*The benefits offered by different types of DGs can also vary greatly.*

It follows that the advantages that these different types of distributed generation can offer to EDBs and/or to Transpower at a particular time and place may also vary substantially. Sometimes there will be clear benefits and in other circumstances distributed generation will serve only to increase network costs. These factors consequently have a critical bearing on whether a payment to a DG in a particular instance will be beneficial to consumers.

## 2.2 Impacts of distributed generation upon networks

In principle, distributed generation can reduce stress on distribution and transmission network infrastructure – especially during peak times when capacity constraints are emerging. In the longer term this can mitigate the need to invest in maintaining and upgrading those networks. Specifically, customers with distributed generating units may be able to:

- reduce their reliance on the grid during peak periods by meeting a greater proportion of their requirements from electricity they generate themselves (although, this will clearly not apply to those DGs that export nearly 100 per cent of the electricity that they generate); and
- export surplus energy into the distribution network at peak times, potentially reducing the need to transport electricity from generators located further away through the centralised network and, in turn, the need to invest in expanding and maintaining that network.<sup>12</sup>

However, the extent to which distributed generation will give rise to these benefits in practice depends on the specific circumstances. In general terms, if there is an imminent need to invest in new network capacity, and distributed generation of sufficient capacity and reliability is able to defer or down-size that investment or reduce operating costs, there is a clear benefit. Where that is not the case, the

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<sup>11</sup> There is often little difference between these types of generators and equivalent transmission-connected generators, aside from the fact that they happen to be connected to the distribution network.

<sup>12</sup> Although this is undoubtedly a potential benefit of distributed generation, it should be noted that it is very difficult (impossible, really) to identify with any precision where the electricity that a customer has consumed has come from in the network.



benefits to networks diminish considerably, or there may be no benefits.<sup>13</sup> We elaborate below.

### 2.2.1 Location of the DG

The value of a DG in reducing the need for investment in either the distribution or the transmission network will depend on whether it is connecting/connected where additional network investment will soon be needed, or where there is spare network capacity.<sup>14</sup> More specifically:

- the network cost savings from distributed generation connecting where there is sufficient spare network capacity to meet current and forecast demand are likely to be low,<sup>15</sup> since the value of any potential deferral or down-sizing of future network investment is relatively low;<sup>16</sup> but
- as the need to invest in new network capacity approaches in a location, the potential network cost savings from additional distributed generation output will increase, since the value created through any potential deferral or down-sizing of that imminent network investment is closer in time.

*To defer network costs, a DG must be investing in the right place and at the right time.*

In other words, the benefits of additional distributed generation in a location will vary substantially over time – potentially quite dramatically. Figure 2.1 below illustrates the familiar ‘saw-tooth’ pattern that is often seen when strong economies of scale result in new capacity being added in large increments, thereby creating significant spare capacity once investments have been made.

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<sup>13</sup> The Essential Services Commission (ESC) of Victoria reached the same conclusion in its recent discussion paper on the ‘true value of distributed generation’, concluding that the benefits were: “highly dependent on the location of the generation and its ability to provide supply when network demand is high.” See: Essential Services Commission, *Inquiry into the True Value of Distributed Generation: Our Proposed Approach*, December 2015, p.20.

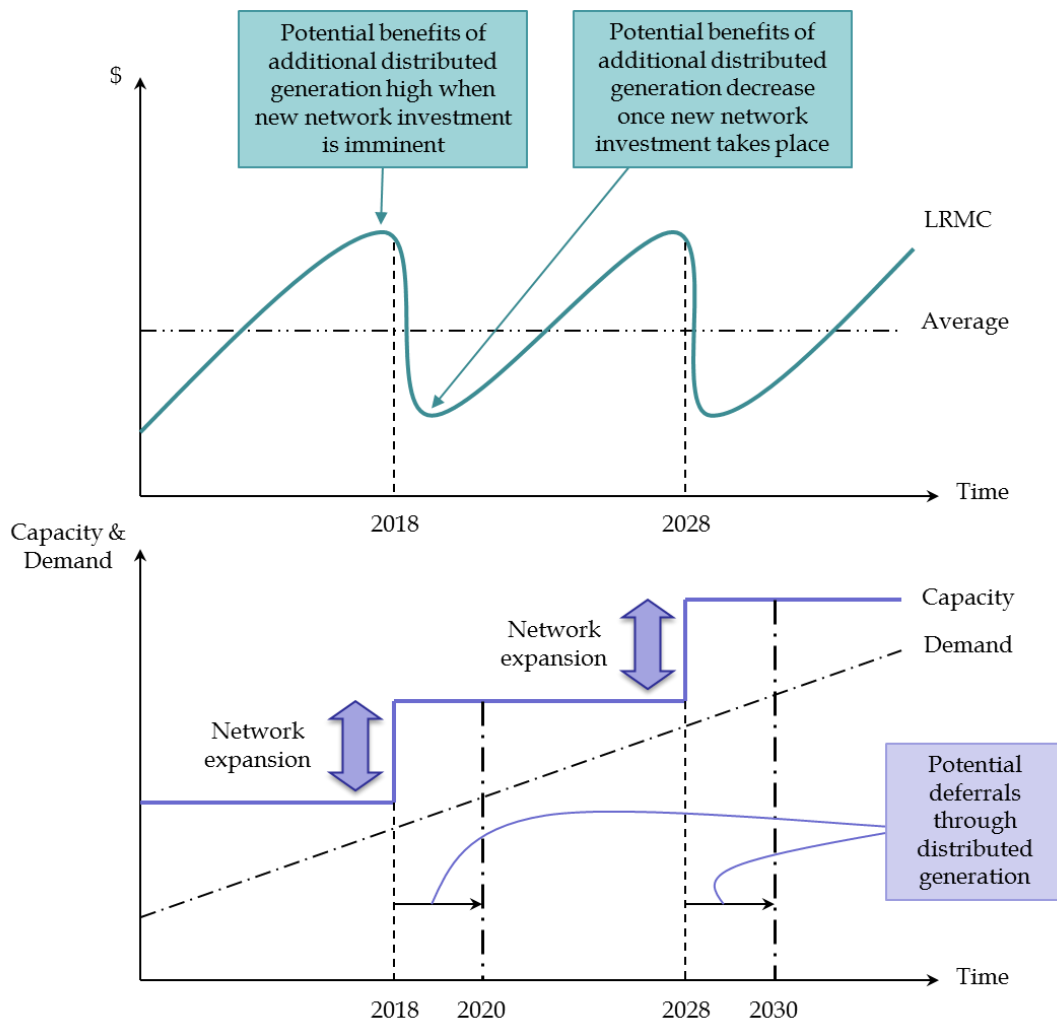
<sup>14</sup> Note that the network cost savings may also vary depending on the voltage level at which an embedded generator connects. Specifically, the more of the network a DG uses to deliver electricity, the more network assets that an EDB will need to continue investing in and maintaining. In other words, there is also a ‘voltage-specific’ element of location.

<sup>15</sup> Costs may even increase if the additional generation output results in bi-directional flows and increases fault levels – see further discussion below.

<sup>16</sup> If additional investment is not going to be needed for, say, another twenty years, the saving (in net present value (NPV) terms) associated with pushing that investment need back by, say, another one or two years may be trivial. Conversely, the saving (in NPV terms) associated with deferring imminent network investment by, say, one or two years, is likely to be high.



**Figure 2.1: Potential benefits from distributed generation over time**



*The benefits from distributed generation fluctuate over time with the investment cycle.*

Figure 2.1 illustrates that the potential cost savings<sup>17</sup> that can be made by pushing back an imminent (e.g., in 2018) investment in, say, the transmission network are large. However, once the investment has happened, the potential for further savings falls away and efficiency is instead maximised – and the costs for consumers minimised – by utilising that new capacity rather than encouraging further investment in distributed generation (or additional export from existing plant).

In other words, the potential benefits to be obtained from distributed generation in any particular location hinges critically on the point of time in the investment cycle. This is an important point to understand in the current context, since the \$2 billion of new investment undertaken recently by Transpower can be expected to have reduced substantially the forward-looking benefits obtainable from distributed generation throughout much of the grid. We return to this point later.

<sup>17</sup> These potential cost savings are represented in this instance by the long-run marginal cost (LRMC) of network capacity.



## 2.2.2 Type of DG

Even if a DG is investing in the right place and at the right time, it must still be the right *type* of generator before it can reliably deliver network cost savings. If the generation capacity in question is too small or too unreliable to have a material effect on projected distribution and transmission system requirements, then it will not deliver any material benefits in the form of reduced forward-looking network costs.

*Not all types of distributed generation can deliver network cost savings.*

An obvious example is intermittent forms of distributed generation such as wind or solar. In the absence of storage (e.g., provided by batteries), these types of generation are unlikely to form a plausible substitute for distribution and transmission network assets. For example, Transpower is highly unlikely to view incremental output from a wind farm as a viable non-network alternative for addressing a pending network constraint.

The simple reason is that if the wind does not happen to be blowing during a period in which Transpower is relying on that incremental capacity to meet peak demand in a location, then a constraint may emerge and, in the worst case scenario, there may be outages. In contrast, it will know that an appropriately sized network investment can be relied upon to meet demand in such circumstances in the overwhelming majority of cases.

## 2.2.3 Potential costs of distributed generation

There may be circumstances in which distributed generation is built where it is not needed, or where it is too small or unreliable to impact on the need to invest in either the distribution or the transmission network. On these occasions, there will be a duplication of costs because, in addition to the costs the EDB incurs connecting the DGs, the networks may still have to build the same infrastructure that they would have built in the absence of that generation.

*Distributed generation can sometimes give rise to additional costs for networks.*

Distributed generation may also give rise to other incremental costs for network businesses and, potentially, for other market participants. These may include some or all of the following (note that although some of these costs may be recoverable via the connection charging framework in the Code, others are likely to be less amenable to recovery by this means, in practice):

- any additional spending on distribution infrastructure that is needed to facilitate a greater amount of distributed generation to be exported throughout the local network whilst ensuring compliance with the applicable reliability standards;<sup>18</sup>
- the costs that EDBs incur interacting and transaction with distributed generators, such as the costs associated with negotiating and entering into connection agreements; and/or

<sup>18</sup> For example, this might include upgrading transformers or switchgear in order to prevent the risk of higher fault levels.





- any proliferation of intermittent sources of distributed generation that causes existing generation assets to be ramped up or down more often, or requires Transpower to buy more ancillary services, e.g., to manage frequency variations.

For those reasons, it is important to recognise that more distributed generation is not necessarily better. Although distributed generation can, in certain circumstances, give rise to significant forward-looking network cost savings, in others it can lead to needless additional costs for no material benefits. It is also important to recognise that the potential benefits offered by distributed generation are often attainable through other types of non-network solutions.

#### 2.2.4 Potential substitutes for distributed generation

Distributed generation is not the only non-network solution that can give rise to forward-looking network cost savings. There are many other ways to reduce the strain on distribution and transmission network infrastructure during peak times when capacity constraints are emerging. Other potential non-network alternatives include (but are not limited to) the following:

- **transmission-connected generation** – there is often little difference between DGs and transmission-connected generators, aside from the fact that they happen to be connected to the distribution network;
- **demand-side management solutions** – there is a variety of ways in which the demand-side might respond during peak periods, e.g., through controllable load, installed battery storage, etc.; and
- a variety of other **energy efficiency measures** such as smart appliances (e.g., energy efficient heat pumps, fridges, etc.) and superior insulation (which reduces the need to consume electricity to heat living and working spaces).

*Distributed generation is not the only non-network solution that can give rise to forward-looking network cost savings.*

If these non-networks solutions emerge in the right places, at the right times and on a sufficient scale, then they too might reduce the need to invest in maintaining and upgrading the distribution and transmission networks. Moreover, depending on the circumstances, they may deliver greater net benefits (e.g., more benefits, or the same benefits at a lower cost) than DG, i.e., they may be a superior substitute.

### 2.3 Summary

Distributed generation can take many forms, and the potential benefits that it can offer distribution and transmission networks is highly dependent on the location of the generation and its ability to provide supply when network demand is high. If new network capacity will soon be needed, and distributed generation of sufficient capacity and reliability is able to defer or down-size that investment or reduce operating costs, there is a potential benefit.

Where those conditions do not hold, then the potential benefits to networks from distributed generation diminish substantially, or may disappear altogether. The result may be needless cost duplication. And even there are significant potential



benefits, there may be other ways of obtaining the same advantages at the same or lower costs, such as via transmission-connected generation, various demand-side management solutions or other energy efficiency measures.

Obtaining the most efficient combination of network solutions (i.e., poles and wires) and non-network solutions such as distributed and transmission-connected generation and demand-side management is, therefore, a challenging balancing act. There can be no presumption that one type of solution will be superior to the other – e.g., it cannot simply be assumed that ‘more’ distributed generation is better than ‘less’ – and this should be reflected in any regulatory pricing arrangements.



### 3. Overarching objectives

There are a number of key attributes that any pricing principles for distributed generation should seek to exhibit in order to promote efficiency. These are informed to a considerable degree by the basic characteristics of distributed generation described in section 2. We describe each of these overarching objectives in turn, below.<sup>19</sup> Note that, although they are discussed separately, they do not exist in ‘watertight compartments’. Rather, there is significant overlap between them.

#### 3.1 Cost minimisation and reflectivity

Promoting the efficient operation of the electricity industry for the long-term benefit of consumers requires network quality, safety, reliability and security of supply requirements to be met at efficient long-term costs, taking into account both network and non-network options, including distributed generation. This will be achieved if (amongst other things):

*The aim should be for demand to be met at the lowest total system cost and for prices to reflect those costs.*

- demand is met at the lowest total system cost (accounting for reliability standards), which requires the use of an efficient combination of network and non-network solutions to be deployed; and
- prices to reflect those costs and, more specifically, this requires:
  - DGs to be remunerated for the costs that they allow network to avoid and to pay for the additional costs that they cause them to incur; and
  - final customers to share in any network cost savings precipitated by DGs, i.e., lower costs should flow-through into final electricity prices.

There are several factors that could compromise the achievement of this objective. For example, price signals might encourage investment in DG that will not reduce forward-looking costs, or might encourage inefficient use of existing assets. Alternatively, efficient investment might occur, but not ultimately translate into lower overall costs and prices for consumers because of the way that DGs are remunerated. We explore both of these issues in section 4.1.2.

#### 3.2 Technology neutrality

A closely-related principle of best practice energy market regulation is technology neutrality. Regulations should be designed so as not to bias any particular solution. Rather, they should be framed to encourage efficient, market-like outcomes so that they do not act as a barrier to the use of whatever technology delivers the most cost-effective service.

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<sup>19</sup> We note that the Australian Energy Market Commission (AEMC) is adopting a very similar set of objectives to assess a proposed rule change that would alter significantly the pricing arrangements for distributed generation in Australia. Axiom Director, Hayden Green, led this rule change for 4 months (from October 2015 to March 2016). The AEMC’s assessment criteria can be found on slide 9 of the presentation available [here](#).



*Technologies that offer the same net benefits should pay the same and be paid the same.*

As a general rule, in order for there to be efficient incentives for investment in network and non-network solutions – including distributed generation – there should, to the greatest extent possible, be equality of treatment of the benefits and costs within the pricing framework. Put simply, alternatives that offer similar forward-looking network benefits should, all things being equal, pay the same network charges and receive the same level of remuneration.

For example, in Australia, distribution and transmission network service providers are permitted – and incentivised through the regulatory regime – to make payments to providers of non-network solutions (including DGs) where they can provide a cheaper alternative to a network augmentation. These payments – termed ‘network support payments’ – are negotiated between the network business and the prospective provider of network support.

By definition, these agreements will be struck when the network business has the opportunity to pay less than what it would have spent on a network solution (the regulatory arrangements then allow it to retain a share of those savings), and the non-network provider will earn at least a ‘normal’ return on investment. Any type of non-network provider can receive these payments, for example:

- if it is cheapest for a network business to pay a DG to provide extra capacity instead of upgrading its network assets, then it can enter into an agreement to procure that network support; but
- if the most cost-effective solution is to procure transmission-connected generation capacity or, say, some form of demand-side response, then the network has an incentive to select those options.

In other words, if a particular technology – distributed generation or otherwise – has the potential to precipitate network savings, there is theoretically the scope for a network support payment to be made. Whether this will always transpire *in practice* depends upon the transaction costs involved in negotiating such agreements.<sup>20</sup> Nevertheless, on the face of it, the Australian arrangements do not clearly bias one form of technology over others.

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<sup>20</sup> The AEMC is currently exploring this issues in its ‘local generation network credits’ rule change process. The proponents of this rule change request have claimed that network support payments are not accessible, in practice, to *smaller* DGs, because the benefits on offer to networks will almost always be outweighed by the transaction costs of entering into contracts (they also claim that networks demand firm capacity – and to be indemnified against any quality of service standard penalties – which are very difficult conditions for smaller DGs to meet). However, there is scope under the Australian rules for small generation market aggregators to compile a *portfolio* of DGs (or demand-side response, as the case may be) and to approach networks with a more valuable proposition. There are firms in the Australian market already engaging in this activity – such as Reposit Power. It therefore remains to be seen whether there are any genuine barriers to any DGs gaining access to network support payments, provided that they can contribute to network cost savings. This is something that the AEMC can be expected to consider at length.



### 3.3 Proportionality and predictability

Any pricing arrangements for distributed generation should seek to achieve 'proportionality' by striking the best possible balance between providing the right investment signals, while ensuring that any arrangements remain relatively predictable and do not become unduly administratively burdensome. This is not a straightforward task, since any pricing principles for distributed generation that seek to signal in some way long-run avoided costs may have to navigate a trade-off between accuracy and simplicity.

To illustrate, suppose that Transpower decided to pay DGs a price that reflected an estimate of the forward-looking transmission network cost savings. One approach would be to make this price available to all types of DGs and to base the tariff on, say, estimates of forward-looking LRMC across a broad geographic region, e.g., the lower North Island. This approach would be relatively simple to undertake and easy for DGs to predict and understand. However, the obvious drawback is that it would not send accurate price signals, since:

- by making the tariff available to all DGs, Transpower would be making payments to types of DGs that are unlikely to be capable of giving rise to transmission cost savings, e.g., intermittent generators without storage; and
- by applying the same price across a very wide geographic area, by definition, this would be likely to send the wrong signals most (if not all) of the time, i.e., the use of a very broad average would:
  - under-signal the potential cost savings from distributed generation in locations where it would be most beneficial, risking under-investment by DGs – and perhaps not deferring network costs as a consequence; and
  - over-signal the potential cost savings from distributed generation in locations where it is not needed, risking the needless duplication of costs and inefficient usage of existing transmission network infrastructure.

*A balance must be struck between sending the right price signals and keeping things simple and predictable.*

Conversely, a more complex tariff design price that relate to more specific geographic areas (or even to particular assets) and is limited to particular types of DGs can be expected to produce the most efficient investment signals. However, these calculations may be costly to undertake and more difficult for DGs to understand and predict when making investment decisions. There is no 'unambiguously correct' way to strike this balance – but some options are nonetheless superior to others.

### 3.4 Symmetry of benefits and costs

If it is accepted that DGs – and, indeed, other non-network solutions – should be rewarded for net benefits they may offer to networks (i.e., avoided network costs), then it follows that they should also be liable in some way for any additional costs that they impose on those providers. In other words, there should be symmetrical treatment of incremental benefits and costs within the pricing framework.



As noted above, distributed generation does not always give rise to forward-looking network cost savings. In some circumstances, it can give rise to material cost increases for distribution and/or transmission businesses, e.g., because of the emergence of bi-directional flows across distribution networks which, absent additional investment in switching gear, would increase fault levels. There should ideally be the scope for networks to recover those costs from DGs in some manner.

### 3.5 Summary

There are a number of key attributes that any pricing principles for DG should seek to exhibit in order to promote efficiency. These overarching objectives are summarised in the table below.

**Table 3.1: Overarching objectives**

Objective	Explanation
<b>Cost minimisation and reflectivity</b>	The aim should be to meet demand at the lowest total system costs (using both network and both non-network solutions), and for prices throughout the supply chain to reflect those underlying costs of supply.
<b>Technology neutrality</b>	Complementing the previous objective, regulations should be designed so as not to bias any solution, i.e., they should not act as a barrier to the use of whatever technology delivers the most cost-effective service.
<b>Proportionality and predictability</b>	Any reform should seek to strike the right balance between providing the right investment signals, while ensuring that the regime remains relatively predictable and does not become unduly administratively burdensome.
<b>Symmetry of benefits and costs</b>	If it is accepted that DGs – and, indeed, other non-network solutions – should be rewarded for any net benefits they may offer to networks, then it follows that they should also be liable for any additional costs that they impose.

Note that it may not be possible to perfectly fulfil all of these objectives simultaneously. Nevertheless, they serve as sound guiding principles against which to assess both the existing arrangements and the proposed reforms.



## 4. Assessment of the status quo

In this section we assess the status quo against the overarching objectives set out in section 3 and explain why there is a reasonable basis to conclude that the pricing arrangements for distributed generation, when combined with the current TPM, have resulted in inefficient outcomes.

### 4.1 Unlikely to minimise or reflect costs

There are two critical questions to consider insofar as this criterion is concerned. The first is whether limiting the charges to DGs for connection services to the level of incremental cost might compromise EDBs' ability to recover fixed costs efficiently. The second is whether ACOT payments linked to reductions in EDBs' RCPD-based interconnection charges are likely to reflect genuine reductions in transmission network costs. We explore these in turn below.

#### 4.1.1 DGs do not contribute to common costs

In industries characterised by large fixed costs, such as electricity distribution and transmission, the most efficient usage of the existing network assets is usually obtained through the application of a "two-part tariff" that applies the "Ramsey-Boiteux"<sup>21</sup> pricing principle. Insofar as connection services are concerned, application of this principle is likely to require:<sup>22</sup>

- a charge that signals to users the *incremental costs* that they impose through their actions – all other things being equal, this will maximise demand for the service in question, which is desirable; and
- additional charges that recover the service provider's fixed (non-marginal) *common costs* in the least distortionary manner possible, e.g., through fixed charges based on the extent to which respective customers are willing to pay.

The second component is needed because, as the Consultation Paper explains,<sup>23</sup> if an EDB set prices for all connection services equal to incremental cost, it would not recover its full costs. It also tends to be the more crucial of the two, since it is usually the more difficult to implement. The challenge is to recover common costs without compromising the static efficiency created by the incremental cost based charge.

Presently, the pricing principles for distributed generation set out in the Code limit the options that EDBs' have at their disposal when it comes to recovering common costs from connecting parties. Specifically, they prevent EDBs from allocating any

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<sup>21</sup> Ramsey, 'A Contribution to the Theory of Taxation', *Economic Journal* (1927), pp.47-61.

<sup>22</sup> For a more extensive discussion of these points, see: Green *et al* (2014) *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, Appendix A2.

<sup>23</sup> Consultation Paper, §3.2.3.



share of common costs to DGs. The upper limit for charges paid by DGs for connection services is incremental cost.

*The current restriction seems to be, at best, unnecessary and, at worst, distortionary.*

To be sure, it is possible that charging DGs no more than incremental cost and recovering 100% of common costs from other customers is the least distortionary way to allocate those fixed imposts. However, for the current arrangements to be justified, one would first need to be confident that this would be the case for all DGs, all of the time. As the Consultation Paper points out:<sup>24</sup>

*'While it may be efficient for owners of distributed generation not to pay common costs in some situations, it is unclear why this would be inefficient in all cases.'* [Emphasis added]

It might sometimes be efficient for a share of common costs to be recovered from DGs and, currently, that cannot happen. However, as we explain in section 5.2.2, if EDBs do indeed allocate a share of fixed common costs to DGs, this may have significant implications for investors' choice of generation technology, depending upon what happens with the TPM.

#### **4.1.2 ACOT payments are likely to exceed avoided costs**

The current arrangements also require EDBs to pay DGs a sum reflecting any costs that they avoid as a result of them connecting. As we noted earlier, the most common practice is for an EDB to base that payment on any estimated reduction in its transmission charge brought about by the DG connecting. For example:

- a DG connecting in a particular location might mean that the EDB expects its contribution to RCPD will decrease in a number of the 100 peaks over which it is measured under the current TPM;
- this might result in the EDB being allocated a smaller share of Transpower's 'interconnection costs', which are assigned amongst load customers (i.e., EDBs and major industrial customers) based on their contribution to RCPD; and
- if so, the EDB will anticipate 'avoiding some costs of transmission' (or, more accurately, avoiding some transmission *charges*) on account of the DG connecting, and this might form the basis of the 'ACOT payment'.

In other words, the term 'avoided cost of transmission' (ACOT) is framed from the EDB's perspective, i.e., the 'cost' in 'ACOT' is a cost *to the EDB* in the form of transmission *charges*. However, a reduction in RCPD-based transmission charges to an EDB is not necessarily synonymous with an equivalent reduction in forward-looking transmission costs.

In section 2.2, we explained that network cost savings are potentially obtainable in circumstances in which there is an imminent need to invest in new network capacity, and distributed generation of sufficient capacity and reliability is able to

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<sup>24</sup> Consultation Paper, §3.2.9.





defer or down-size that investment or reduce operating costs. These are quite limited circumstances. In comparison, the design and application of the RCPD-based charge<sup>25</sup> makes it much easier for a DG to give rise to a reduction in this component of an EDB's transmission charges. For example:

*There are many instances in which a DG may reduce an EDBs' transmission charges without reducing forward-looking network costs.*

- when there are no imminent transmission constraints in an interconnection pricing region (i.e., when there is ample spare capacity), a DG can lead to a reduction in an EDB's RCPD and, in turn, its transmission charges, without there being any material effect on forward-looking network costs;
- when there are imminent transmission network constraints in one part of a pricing region ('location A'), a DG can cause a reduction in an EDB's RCPD and, in turn, its transmission charges, even though it is located in another part of the region ('location B') where it has no impact on the constraint; and
- even if a DG is locating where there is an emerging transmission constraint and reducing an EDB's RCPD,<sup>26</sup> it may still not reduce forward-looking network costs, e.g., if may be an intermittent generator without storage, in which case it would not be a sufficiently reliable substitute for a network investment.

In other words, there is quite a broad range of scenarios in which DGs could be receiving ACOT payments from EDBs that exceed the value of any reduction in forward-looking transmission costs. Moreover, there is likely to be even less correlation between reductions in an EDBs transmission charges and reductions in its own forward-looking *distribution* costs. The net result may be that final electricity consumers end up paying twice:

- first to cover Transpower's total revenue requirement, since transmission charges under the TPM are 'recoverable costs' for EDBs under the Commerce Commission's default price/quality path; and
- then to compensate DNSPs for any ACOT payments, which are also a recoverable cost - even if the DGs have had no material impact upon forward-looking transmission (or distribution) costs.

If that is the case, electricity prices for end customers will be higher than necessary in the short-term, under the status quo. It is worth noting also that, even if a reduction in an EDB's RCPD-based charge reflected a reduction in forward-looking transmission and/or distribution costs, that does not necessarily mean that consumers benefit from lower prices. That is because 18 of the 29 EDBs pass on 100% of the avoided interconnection charge to DGs.<sup>27</sup>

<sup>25</sup> In particular, the charge is highly averaged, i.e., it is applied to four very broad interconnection pricing regions and measured over 100 peak periods, with all customers in all locations facing the same price per kW. It also reflects Transpower's historical costs, i.e., they are linked to its annual revenue cap, as determined under its individual price/quality path, such that they reflect predominantly returns on and of its existing assets.

<sup>26</sup> It can do this by generating during some of the 100 measurement periods.

<sup>27</sup> Electricity Authority, *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation, Working Paper*, 19 November 2013, p.20.



The most likely scenario is that providing ACOT payments to DGs has increased prices for final consumers, overall.

In other words, with respect to the majority of EDBs, in these circumstances, every forecast reduction in transmission network capital expenditure would result in an equal and offsetting additional cost in the form of ACOT payments. There would be no reduction in total system costs. Instead, the same amount of total revenue in aggregate would need to be recovered from final electricity customers through distribution and transmission network charges.<sup>28</sup>

The only circumstances in which final electricity customers could have paid less under the current arrangements is if the ACOT payments made to DGs were *less* than the network costs that they had enabled EDBs and Transpower to avoid. It is certainly conceivable that the ACOT payments made to *some* DGs might have under-represented the quantum of network costs savings that they have delivered.<sup>29</sup> However, we expect that there would be many more cases in which these conditions do not hold.

The factors set out hitherto mean that it is altogether more likely that, *in aggregate*, the ACOT payments that have been made to DGs exceed the network costs that have been avoided, resulting in higher prices for final consumers overall. However, it is important to recognise that this does not reflect a problem with the *pricing principles for distributed generation, per se*. Rather, it largely serves to highlight a shortcoming in the price signal being provided by the RCPD-based interconnection charge *in the TPM*.

By definition, if the price signals being sent by the TPM reflected perfectly Transpower's forward-looking costs (which is impossible in practice), then ACOT payments would *always* reflect avoided transmission costs – and the issues described above would not arise. As we explain in our report<sup>30</sup> in response to the EA's second Issues Paper on the TPM ('the Issues Paper'), much of the inefficiency arising at present stems from the fact that the RCPD-based signal is *too strong*.

Specifically, following the completion of Transpower's recent major investment programme there is now significant spare capacity throughout much of the grid, i.e., the available transmission capacity comfortably exceeds RCPD. It is consequently inefficient for load customers to be seeking to avoid transmission charges by curtailing demand through distributed generation since, in most cases, it would not be avoiding transmission costs, i.e., the problem described above.

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<sup>28</sup> The only difference is that that a sum of money that would otherwise be paid to one group of market participants (e.g., engineering and construction firms that build transmission network assets) would instead be paid to DGs in the form of ACOT payments.

<sup>29</sup> For example, it is possible that there have been DGs located in the vicinity of network constraints that have offered reliable supply during peak periods, thereby deferring network investments. The ACOT payments that they have received may not fully reflect the net present value of those deferral benefits. We explore this possibility in more detail in section 5.3.

<sup>30</sup> See: Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper, A Report for Transpower*, July 2016 (hereafter: "TPM report").



This particular issue therefore does not necessarily need to be addressed by removing Schedule 6.4. Instead, it could be assuaged by modifying the TPM. For the reasons set out at length in our TPM report, we do not agree that the proposed 'area of benefit ('AoB')' charge would be an effective means of dealing with the above issue, since it would introduce myriad inefficiencies.<sup>31</sup> However, it could be addressed in other ways, such as by:

*The problem described above could be mitigated by reforming the TPM.*

- retaining the RCPD-based charge, but temporarily weakening the price signal by increasing the number of periods over which contributions to RCPD are measured, e.g., to 1,000 or 5,000; or
- replacing the RCPD charge with a long-run marginal cost (LRMC) charge that provided an explicit signal to load and, potentially, generation customers of Transpower's forward-looking costs.

To be sure, a number of matters would need to be considered before either option was implemented. For example, before LRMC charge could be introduced thought would need to be given to the methodology with which to calculate it, the geographic areas over which it should apply, how often it should be reset, whom should pay it, and so on. These matters do not have straightforward answers – but they are addressable.

Nevertheless, provided that these relevant issues can be satisfactorily resolved, each of these options consequently has the potential to improve the efficiency of the price signal provided by the current TPM and, in turn, reduce substantially the problem set out in this section – perhaps even eliminate it. That being the case, it is unclear whether it is either necessary or desirable to remove schedule 6.4 to achieve that objective – TPM reforms could do so.

*Reforming the TPM would not fix technology neutrality problems.*

However, although modifying the price signals in the TPM could reduce the number of instances in which ACOT payments are made to DGs when transmission costs have not been avoided, it would not address the problem set out in the following section. Namely, the pricing arrangements in schedule 6.4 have distortionary impacts upon investment incentives, because they provide an additional revenue stream to DG that is not available to other technologies.

## **4.2 Not technology neutral**

The current pricing arrangements for DGs are likely to distort the choice between different types of non-network solution, making firms more likely to invest in distributed generation, when other technologies are equally feasible and may offer greater market benefits. The connection charges that DGs must pay, *vis-à-vis* transmission-connected generators can be significantly more favourable, and they may also receive an additional revenue stream in the form of ACOT payments.

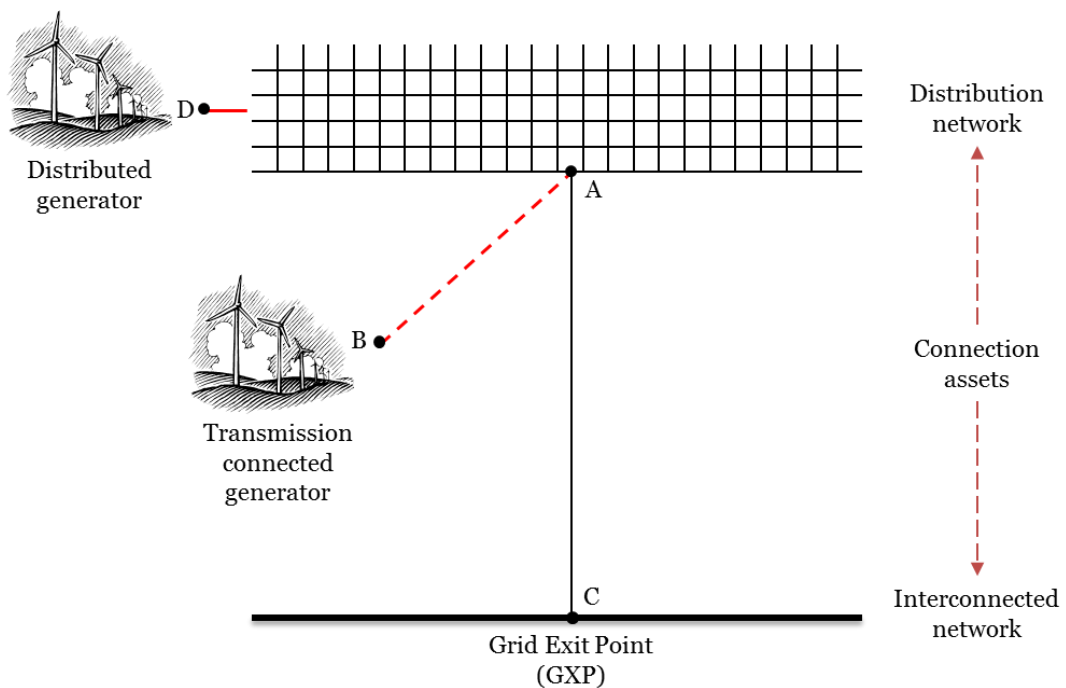
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<sup>31</sup> See: TPM report, §3, 4 and 5.



To illustrate, consider a simple example in which a generator is deciding whether to connect to the transmission or the distribution network. When a generator connects to the transmission network, it must pay for the transmission connection assets that it is deemed to use. Importantly, it is also required to make a contribution to Transpower's common costs. In the simplified grid displayed in Figure 4.1, suppose that a generator is considering building plant at location B, and connecting to the transmission grid at location A.

**Figure 4.1: Connection charges paid by generators**



If the generator proceeded with this investment and entered into a new investment contract with Transpower (rather than building the new dedicated connection assets itself<sup>32</sup>), it would be required to pay the following transmission charges:<sup>33</sup>

- new investment charges for capital recovery on the new link between A and B and any new switchyard equipment at the grid exit point (GXP);
- injection overheads related to the new switchyard assets; and
- a share of the connection charges associated with the link between A and C used by both the generator and the local load; namely:
  - the generator will pay for a share of the line based on its anytime maximum injection (AMI); and
  - the balance will be paid by the load (i.e., the distributor) based on its anytime maximum demand (AMD).

<sup>32</sup> Namely, the new line from B to C and the necessary switchyard assets at the grid exit point

<sup>33</sup> If the generator was based in the South Island, it would also pay HVDC charges. However, for the sake of simplicity, we assume that the generator is based in the North Island.



In other words, the transmission-connected generator would be required to pay for the incremental costs of connecting it to the transmission network (i.e., for the new 'dedicated' connection assets), a share of the costs of the *existing* assets that it is deemed to be sharing with existing users (i.e., 'shared' connection assets) and a contribution to injection overheads. However, the generator would not have to contribute to the fixed common costs of the interconnected network.

Now suppose that the generator was considering connecting to the distribution network. Imagine that the generator is identical to that from the previous example, i.e., same capacity, same technology, etc. The only difference is the location of the connection point (point D instead of point B) and the fact it is embedded. If the generator proceeded with this investment and embedded its plant into the distribution network at location D, then it would:

- pay the EDB for the incremental costs associated with its connection to the distribution network – but not for any common costs of existing assets;
- pay Transpower for a share of the connection costs associated with the link between A and C if it injects power into the transmission grid; namely:
  - if the local load does not account for all of its capacity and its AMI was positive this charge would be positive (albeit less than the transmission-connected generator would pay); but
  - if the local load always takes 100% of the power injected at point D then the DG will not have to make any contribution to the sunk costs of the existing link between A and C; and
- receive an ACOT *payment* from the EDB reflecting the costs that it was estimated to avoid by the generator connecting at location.

*It is easy to see why a generator might have a strong incentive to embed, even when more efficient options are available.*

When faced with the alternatives of connecting to the transmission network or the distribution network, it is easy to see why a generator might have a strong incentive to choose the latter. This has the potential to give rise to undesirable distortions. Specifically, it is likely to encourage generators to embed when there may be greater market benefits delivered through them connecting to the *transmission* network. The same general point applies to other non-network solutions.

For example, it could be that an aggregator could offer the same level of network support through installing battery storage at certain points throughout the distribution network. This may offer significantly greater net market benefits than embedding generation at location D – but it may be the less financially attractive of the options because it would not attract an ACOT payment.

The differential treatment of connection costs and the provision of ACOT payments to DGs means that one type of non-network solution is artificially advantaged. The status quo is therefore not technology neutral. Rather, it provides a false advantage to DGs at the expense of alternative technologies. This may lead to inefficient investment outcomes and higher prices for consumers in the long run, relative to what they might otherwise have been.



### 4.3 Predictable but not proportional

It should be relatively self-evident from the analysis set out in the two previous sections that we do not consider the current arrangements strike a particularly good balance between sending efficient price and investment signals and minimising administrative costs. For example, those businesses that are basing ACOT payments on reductions in their own RCPD-based charges are likely to be sending inaccurate price signals almost all of the time, since they will be:

*The inefficiencies associated with the status quo's imperfect price signals are likely to outweigh any benefits from its predictability or simplicity.*

- *over*-signalling the potential forward-looking transmission cost savings in those locations in which there is sufficient capacity to meet current and forecast demand, i.e., because the long-run marginal cost (LRMC) of future network capacity is low in those places at those points in time; and
- *under*-signalling the potential forward-looking transmission cost savings in those locations where constraints are emerging, since the LRMC of future network expansion may be high in those places at those times – potentially higher than indicated by any RCPD-based ACOT payments.

As noted above, given the current point of time in the investment cycle, it is the former that is giving rise to the most distortions under the current TPM. As we explained above, this problem could be mitigated to a considerable extent by changing the TPM. The two potential options we noted above (which do not amount to an exhaustive list) were: weakening temporarily the strength of the existing RCPD signal, or introducing an LRMC charge.

In the absence of such reform, the costs of the inefficiencies associated with the imperfect current price signals are likely to outweigh any advantages associated with the predictability or administrative simplicity of the arrangements. The key question is whether the proposed reforms are likely to strike a better balance, taking into account whether departing from the status quo might itself be seen as an unpredictable development that undermines certainty. We consider this more in section 5.3.

### 4.4 Allows for some symmetry

We explained above that distributed generation can sometimes give rise to material cost *increases* for distribution and/or transmission businesses, e.g., because of the emergence of bi-directional flows across distribution networks which, without more investment in switching gear, would increase fault levels. In theory at least, EDBs could charge DGs for those additional costs under the current arrangements, since they would fall within the definition of 'incremental costs'.



*DGs receive ACOT payments that will often overstate the network benefits that they have delivered – this represents an asymmetry.*

Whether it would be feasible for EDBs to do this in practice is less clear. For example, bi-directional flows may not emerge for some time after a DG (or a series of DGs) has connected to the distribution network. At that point it is likely to be challenging – although not impossible – to design charges to signal those incremental costs.<sup>34</sup> In this respect at least, there is scope for there to be at least some degree of symmetry of benefits and costs under the status quo.

However, the biggest problem with the status quo is not that EDBs cannot charge DGs more when they give rise to additional costs (as noted above, this is at least theoretically possible). For the reasons set out in previous sections, the problem is that, under the current TPM, DGs are remunerated with ACOT payments that will often overstate the network benefits that they have delivered, if any. This is arguably an asymmetry of a kind, i.e., a DG can receive a payment even when they deliver no benefits.

## 4.5 Summary

Table 4.1 summarises our assessment of the status quo against each of the key overarching objectives described in section 3. Note that our conclusions have not been informed in any way by the quantitative cost benefit analysis set out in Appendix D of the Consultation Paper.<sup>35</sup>

**Table 4.1: Assessment of status quo**

Overarching objective	Performance of status quo
<p><b>Cost minimisation and reflectivity</b></p>	<p>The inability of EDBs to allocate a share of common costs to DGs may compromise their ability to set efficient prices – although if they did so, this may have implications for technology neutrality (see section 5.2.2).</p> <p>The ACOT payments made to DGs under the current arrangements are likely to have exceeded any network cost savings, resulting in higher retail electricity prices for consumers overall.</p> <p>However, the second problem listed above arises from the TPM, not the principles in schedule 6.4. If the RCPD price signal was temporarily weakened, or replaced by an LRMC charge, these issues could largely fall away.</p>

<sup>34</sup> For example, this might be achieved through some form of us-of-system charge that was higher during times in which bi-directional flows were expected to arise. Note that, in Australia, this could not be done because, once a DG has connected to a distribution network, the EDB cannot charge it to export energy, i.e., it does not pay distribution use of system charges.

<sup>35</sup> As part of this review, we have identified a number of problems with the assumptions that underpin the CBA. The most significant problem is that a large number of the assumptions that are pivotal to the results appear not to have been substantiated in any way. The CBA therefore does not provide a sound empirical basis for the proposed changes and cannot be relied upon to support the recommendations in the Consultation Paper. Our conclusions consequently rest on the qualitative analyses set out in the chapter and in the Consultation Paper.



Overarching objective	Performance of status quo
<b>Technology neutrality</b>	The arrangements provide an additional revenue stream to distributed generation relative to other types of non-network solutions. This risks distorting investment decisions, leading to prices that are higher than they would otherwise be, over the longer-term.
<b>Proportional and predictable</b>	The status quo appears not to strike the best balance between sending the right price signals and minimising administrative costs. However, this is again largely an issue with the TPM, rather than schedule 6.4.  However, the arrangements are relatively predictable and understood by market participants. It is possible that investment decisions hinged on an understanding that ACOT payments would continue.
<b>Symmetry of costs and benefits</b>	The status quo allows for at least some symmetry in the treatment of benefits and costs in that EDBs can, in principle, charge DGs for any incremental costs they impose upon their own networks.  However, because DGs are remunerated with ACOT payments that will often overstate the network benefits that they have delivered this represents another potentially problematic source of asymmetry.

On the basis of the observations Table 4.1, we consider that there is a sound basis to conclude that the pricing arrangements for distributed generation, when combined with the current TPM, have resulted in inefficient outcomes. However, in many cases it is the transmission pricing arrangements that are primarily responsible, *not* the pricing principles in schedule 6.4.

In particular, modifying the price signals in the TPM could reduce the number of instances in which ACOT payments are made to DGs when transmission costs have not been avoided. As we noted above, this could be achieved by:

- retaining the RCPD-based charge, but temporarily weakening the price signal by increasing the number of periods over which contributions to RCPD are measured, e.g., to 1,000 or 5,000; or
- replacing the RCPD charge with a long-run marginal cost (LRMC) charge that provided an explicit signal to load and, potentially, generation customers of Transpower's forward-looking costs.

If these reforms were implemented, then a great many of the problems highlighted in the Consultation Paper – and attributed to schedule 6.4 – would fall away. The principal issues that the proposal would then be addressing would be those relating to technology neutrality. We elaborate in the following section.





## 5. Assessment of the proposal

In this section we evaluate the reforms proposed in the Consultation Paper against the same overarching objectives outlined in section 3. We highlight a number of areas where those changes are likely to represent an improvement over the existing arrangements. We also identify a number of specific issues that may warrant further consideration before any final decision is made of the precise shape of any reforms.

### 5.1 Unclear effect on forward-looking costs

The reforms proposed in the Consultation Paper would result in fewer instances in which payments are made by networks to DGs when there would be no material forward-looking network cost savings.<sup>36</sup> However, there may also be more instances in which payments are not made to DGs when they could provide material benefits in the form of network cost reductions. This could result in underinvestment in new embedded plant and, potentially, inefficient use of existing assets. It is unclear which of these effects would dominate.

#### 5.1.1 EDBs could make DGs contribute to common costs

We explained in section 4.1.1 that the current pricing principles for distributed generation prevent EDBs from allocating any share of common costs to DGs. As we noted earlier, it is conceivable that it might sometimes be efficient for a share of common costs to be recovered from DGs and, presently, that cannot happen. The reform proposed in the Consultation Paper would provide EDBs with that additional ‘degree of freedom’.

*There is no clear downside to allowing EDBs to allocate a share of common costs to DGs.*

In our opinion, there is no obvious downside to removing this limitation. If EDBs consider that allocating common costs to DGs would be inefficient (i.e., distort efficient investment and usage decisions), then they would still be able to set charges equal to incremental cost. Alternatively, if increasing prices above incremental costs was expected to promote efficiency, EDBs would then have that option at their disposal.

#### 5.1.2 Payments will not happen if network costs will increase

If the reforms contemplated in the Consultation Paper were implemented then, as we understand it, the slate would essentially be ‘wiped clean’.<sup>37</sup> Any payments that are currently being made to DGs under the existing code provisions would cease. Both existing DGs and prospective entrants would then have two options if they wished to receive payments for network deferral benefits:

<sup>36</sup> Although, as we explained above, the same outcome could be achieved simply through reforming the TPM and leaving schedule 6.4 in place.

<sup>37</sup> Although this would depend ultimately on the individual contractual terms. It is possible that some would not be ‘tied’ to the existence of schedule 6.4.



- enter into a contract with Transpower for the provision of a non-network alternative that avoids *transmission* network costs; and/or
- receive some form of payment from their EDBs for avoiding *distribution* network costs, e.g., through the distribution pricing arrangements.

In light of the way in which the current regulatory regime functions (Appendix A provides an overview of these arrangements), Transpower is unlikely to countenance entering into contracts for the supply of a non-network alternative from a DG (or any other supplier of non-network services) unless it is confident that doing so would result in transmission network cost savings. As we explain in more detail in sections 5.3 and 6.2, this would mean that:

- there are existing DGs receiving ACOT payments from EDBs that are not currently<sup>38</sup> giving rise to equivalent transmission network cost savings,<sup>39</sup> and would therefore be unlikely to receive the same payments (or even any payment) from Transpower under the proposed reforms; and
- there are DGs that might have invested in the future so as to receive ACOT payments under the status quo without delivering equivalent reductions in transmission network costs, and that would consequently be unlikely to receive the same (or perhaps any) payment from Transpower under the proposal.

*Transpower and EDBs would be unlikely to make payments to DGs unless they were confident that there would be future network cost savings.*

If the existing Code provisions are removed, EDBs would also have to decide how they will compensate DGs for any benefits that they offer in terms of *distribution network* support. Indeed, the potential benefits from distributed generation described in section 2.2 apply equally to distribution networks. Yet, for whatever reason (perhaps sheer expediency), the majority of EDBs have, hitherto, elected to compensate DGs on the basis of avoided *transmission charges* rather than on the actual network support benefits that they offer.

With the slate ‘wiped clean’ in the manner described above, EDBs would seemingly have a number of options at their disposal. However, perhaps the two most obvious candidates would be:<sup>40</sup>

- to continue to make payments to DGs on the basis of the transmission charges that they allow the EDB to avoid; or
- to limit any payments to DGs to circumstances in which there was expected to be an equal or greater reduction in forward-looking distribution costs.

If an EDB opted for the first approach (despite the criticism in the Consultation Paper and the potential option for the DG to contract directly with Transpower),

<sup>38</sup> In section 5.3 we explore the more challenging scenario of DGs that may have delivered benefits *in the past* that may not have been fully reflected in ACOT payments at that time.

<sup>39</sup> Recall that ACOT payments do not necessarily reflect genuine reductions in forward-looking transmission costs.

<sup>40</sup> We note also that there are EDBs that do not currently base payments to DGs on avoided transmission charges – Orion is one example. These businesses may, of course, choose to retain their existing pricing arrangements if the proposed reform is implemented.



payments to DGs could still be considerable lower than under the status quo. If Transpower implements the changes to the TPM that have been proposed in the EA's most recent Issues Paper (or something like them), then it is likely that:

- the overall magnitude of any ACOT payments would decrease, since a larger proportion of charges would be recovered from generators (meaning that there are less charges for EDBs to avoid, on average); and
- there would be fewer instances in which a DG allowed an EDB to avoid transmission charges, when that did not correspond to an equivalent reduction in transmission costs (which is possible under the status quo, given the current design of the RCPD-based charge)

*Under the proposal, there would be fewer instances of DGs being paid when they do not deliver network benefits.*

If an EDB decided instead to focus on the effects that DGs have on its own network costs), then the existing regulatory arrangements (summarised in Appendix A) mean that it would be unlikely to pay a DG for network support unless it was confident that it would reduce distribution network costs. As with our earlier discussion of transmission costs, this would again mean that:

- there are existing DGs receiving ACOT payments from EDBs that are not currently<sup>41</sup> giving rise to equivalent *distribution* network cost savings,<sup>42</sup> and would therefore be unlikely to receive the same payments (or even any payment) from *an EDB* under the proposed reforms; and
- there are DGs that might have invested in the future so as to receive ACOT payments under the status quo without delivering equivalent reductions in *distribution* network costs, and that would consequently be unlikely to receive the same (or perhaps any) payment from an *EDB* under the proposal.

For these reasons, we consider that, if the proposed reforms are implemented, there is good reason to think that there would be fewer instances in which DGs are being paid sums that exceed the transmission and distribution network support benefits that they are delivering. Instead, such payments are more likely to be limited to situations in which the payee is confident that there would be a genuine network cost saving, over the long-term.

*These benefits are not unique to the proposal. Reforming the TPM could deliver the same benefits.*

On its face, this represents a potential advantage over the status quo under which the payments to DGs will often *exceed* any network cost savings (see section 4.1.2). However, as we have noted on several occasions hitherto, it is critical to realise that *the same benefit* could arguably be obtained by *reforming the TPM*. The benefits are not unique to the proposal in the Consultation Paper and removing schedule 6.4 may *not be the best way* to obtain them.

As we explained above, the same benefits could be obtained by weakening temporarily the strength of the existing RCPD signal or through introducing an

<sup>41</sup> In section 5.3 we explore the more challenging scenario of DGs that may have delivered benefits *in the past* that may not have been fully reflected in ACOT payments at that time.

<sup>42</sup> Recall that ACOT payments do not necessarily reflect genuine reductions in forward-looking transmission costs.



LRMC charge. In other words, it is not correct to say that the proposal would result a greater degree of cost reflectivity. Those outcomes would be achieved *in any event* if the options suggested above were implemented effectively. This affects greatly the potential benefits of the proposed reform.

### 5.1.3 Payments might not happen when network costs decrease

In addition to reducing inefficient investment in and use of distributed generation, the proposal might also *discourage* some *efficient* distributed generation, i.e., investment and/or use that *would* reduce network costs. That would clearly come at some cost. To understand why, it is helpful to first understand why network businesses may have a preference for network solutions.

#### 5.1.3.1 Why networks may understandably favour network solutions

Unless there are specific mechanisms within a regulatory framework to provide network businesses with compelling reasons to pursue non-network alternatives – such as procuring distributed generation – they are likely to have a perfectly understandable preference to adopt network options. For example:

- the culture of a network business may favour network-based solutions, since this is likely to represent the professional expertise of most technical staff;
- there is a mature market of suppliers, products and constructors of network solutions, which makes procurement comparatively straightforward;
- a network business is much more likely to have an established track record of being able to deliver network solutions on time and on budget; and
- network solutions involve a technology that provides a clear delivered reliability, that is primarily passive, i.e., once installed, it delivers the rated capacity in the overwhelming majority of circumstances.

*Network solutions tend to have lower risks and lower transaction costs.*

In contrast, non-network solutions, such as distributed generation, have a number of intrinsic disadvantages, such as:

- they are generally not available as ‘off-the-shelf’ solutions, but must instead be sought out and transacted for as bespoke arrangements that involve significant commitments of time and resources to arrange, conceivably in areas that are at the boundaries of many employees’ professional expertise; and
- they have only a limited track level of deliverability, and may be less reliable than in-place, passive network capacity due to the fact that they generally require a decision and an action by a customer and/or other party outside the network, making them less certain.

In other words, network solutions are generally – and often quite reasonably – perceived as having lower risks, and lower transaction costs. For that reason, regulators are recognising that additional mechanisms are likely to be required to address those factors. The Commission is no different – as we explain below.



### 5.1.3.2 Existing mechanisms to encourage non-network solutions

There are a variety of ways in which the Commission has sought to provide the additional incentives that are likely to be needed to incentivise efficient investment in and use of non-network solutions, such as distributed generation, given the practical factors described in the previous section. For example, in relation to transmission (see more detail in Appendix A):

- Transpower is required to publish an integrated transmission plan, explaining its plans for the grid over the next 10 years. This provides more transparency on its planning activities and decision-making and, in principle, may assist non-network providers to put forward options – including distributed generation – as credible alternatives to network investment.
- Under its IPP, Transpower’s operating expenditure (‘opex’) and ‘base’ capital expenditure (‘base capex’) allowances are both subject to *ex-ante* approval by the Commission, prior to each regulatory period. Under this framework:<sup>43</sup>
  - Transpower is subject to symmetric incentives that allow it to keep 33 cents of each dollar of savings in base capex (i.e., projects less than \$20m) and opex in the control period (and contribute 33c of each dollar of ‘over-spend’), which provides it with additional financial incentives to pursue non-network solutions where that can reduce costs;
  - in evaluating Transpower’s base capex, the Commission may also review the internal processes applied and, in theory, it could challenge the need for a proposed network solution and question whether there are other cheaper non-network options available, i.e., decline to approve a proposal; and
  - Transpower has also been granted an opex allowance of \$8m over 2015-20 to fund a demand response programme<sup>44</sup> - this might reasonably be characterised as a demand response ‘innovation allowance’<sup>45</sup>
- Under the major capex framework, Transpower is required to explicitly consider transmission alternatives when assessing major capex projects.<sup>46</sup> Specifically, when Transpower notifies the Commission of its intention to undertake a major project, they must both agree on an approach to ensure appropriate consideration of non-transmission solutions and a consultation programme.

In relation to distribution (see again Appendix A for more detail):

- Each EDB is required to publish a detailed ten-year asset management plan (AMP) that provides information on how it intends to manage its assets to meet

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<sup>43</sup> Consultation Paper §C.4.

<sup>44</sup> Commerce Commission, *Setting Transpower’s individual price-quality path for 2015 – 2020*, [2014] NZCC 23, §5.183.

<sup>45</sup> This allowance is not direct funding to defer any particular transmission investments. Rather, it is intended to develop and grow demand response capability more generally.

<sup>46</sup> Note that where use of a transmission alternative avoids a transmission investment that would otherwise be major capex, the transmission alternative is called a ‘non-transmission solution’.



consumer demands. This aids transparency and again, in principle, it might make it easier for prospective providers of non-network solutions – such as DGs – to offer alternatives to planned network investments.

- The ‘incremental rolling incentive scheme’ (‘IRIS’) that applies to both opex and capex under the default price-quality path (DPP) provides a mechanism by which suppliers can retain the benefits of efficiency gains beyond the end of a regulatory period, which provides some incentive to EDBs to explore non-network options as a way of potentially outperforming benchmarks.<sup>47</sup>
- At the completion of the Commission’s current review of input methodologies it is likely that the DPP will switch from a weighted average price cap to a revenue cap. This may enhance incentives to pursue any cost reductions that can be obtained through the adoption of non-network options (under a price cap, mechanisms that reduce volume can reduce overall revenues).

*These extra arrangements will go some way to addressing the bias that networks can reasonably be expected to have towards network solutions.*

Perhaps the most noticeable difference between the DPP for non-exempt EDBs (i.e., to sixteen businesses) and the arrangements applied to Transpower is the comparative regulatory scrutiny of capital expenditure (capex). Although the Commission certainly looks at EDBs’ capex forecasts (and their historical spending) when determining the DPP every five years, there is:

- no explicit regulatory approval of capex above a certain threshold like there is for Transpower’s ‘major capex’ projects; and
- no requirement for EDBs to undertake a cost benefit analysis of different options when investments are expected to exceed a certain threshold (which must be done in Australia – see below and Appendix A).

These extra incentive arrangements would go some way to addressing any understandable reluctance on the part of networks to adopt non-network solutions. However, if the proposed reform is implemented, we consider that there is a possibility that networks – particularly EDBs – may nevertheless eschew from adopting non-network solutions (including distributed generation) in some situations in which they may offer network cost savings. We explain why below by drawing upon experience in Australia.

### **5.1.3.3 The Australian experience**

In Australia, providers of non-network services (e.g., generators and suppliers of demand management/response services) are eligible to receive payments for transmission businesses and EDBs for ‘network support’. There are no restrictions on the circumstances in which these payments can be made. If a non-network alternative is cheaper than a network option, then a payment can be made. There

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<sup>47</sup> Another key purpose of the IRIS is to prevent EDBs from being able to boost profits by inflating costs in a particular year of the regulatory period.



are also mechanisms in place to incentivise networks to pursue such solutions in these circumstances, including (see Appendix A for more details):

- the Capital Expenditure Sharing Scheme (CESS) and the Efficiency Benefit Sharing Scheme (EBSS):<sup>48</sup> These schemes are similar to the IRIS described above, in that they provide EDBs and transmission businesses with incentives to invest in and operate their networks efficiently by allowing them to retain a portion of any cost savings, and to share the remaining portion with customers. This incentivises an EDB or transmission business to substitute a non-network solution for a previously anticipated investment in the network, if the former is more efficient; and
- The Regulatory Investment Tests for Distribution (RIT-D) and Transmission (RIT-T):<sup>49</sup> The RIT-D and RIT-T require EDBs and transmission businesses, respectively, to consider the costs and benefits of all credible network and non-network solutions where an investment need is projected to cost \$5 million or more (in the case of EDBs) or \$6m or more (in the case of transmission businesses). In some circumstances, the benefits would be maximised, or the costs minimised, by selecting a non-network solution.

*Most (if not all) investment in non-network options has come from a RIT-T or RIT-D process.*

Notwithstanding the existence of these mechanisms, we understand that there have been relatively few instances in which payments have been made by networks to providers of non-network solutions (including DGs) for network support. We also understand that, when network support payments have been made to non-network alternatives, this has always (or nearly always) been following the application of a RIT-T or RIT-D process.

One of the advantages of the RIT-T and RIT-D processes from the perspective of potential providers of non-network solutions, is that this provides them with sufficient time to develop and offer a solution. As section 6.4 and Appendix A explain in more detail, these opportunities are identified in the businesses' annual planning reports, which allows for more transparency. In summary, in Australia:

- the only circumstances in which networks have procured non-network solutions is when they have been *compelled* to undertake a cost-benefit analysis that gives explicit consideration to those possibilities; and
- when such explicit consideration has not been required – and it is left to the other financial incentives in the regulatory regime to incentivise such conduct – there has been *little or no investment* in such alternatives.

To be sure, it is conceivable that there have been no other opportunities for networks to procure non-network solutions, aside from those that have arisen in the context of RIT-T and RIT-D processes. It is also possible that the networks in question would still have entered into network support contracts with the non-

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<sup>48</sup> See: NER clauses 6.5.8A and 6.5.8, respectively.

<sup>49</sup> See: NER clauses 5.16 and 5.15, respectively.



network providers, even if they had not been compelled to consider those options under the RIT-T and RIT-D frameworks.

But the other possibility is that those cost-saving investments in non-network solutions were made *only because* of the explicit requirement placed on the businesses to consider non-network alternatives. If that is indeed the case, then this has potentially significant ramifications for the proposal recommended in the Consultation Paper. We examine these potential implications below.

#### **5.1.3.4 Potential implications**

As we set out in more detail in Appendices A and B, New Zealand has analogous arrangements to *some* of the mechanisms contained in Australia's National Electricity Rules (NER). For example, both jurisdictions contain network planning and expansion frameworks, and they each contain efficiency sharing schemes (the CESS, EBSS and the IRIS, respectively). However, while the NER contain the RIT-T and RIT-D, in New Zealand:

- Transpower is only required to give explicit consideration to non-network options as part of a regulatory investment approval process when the estimated cost of the outlay is more than NZ\$20m, versus A\$6m under the RIT-T; and
- there is no equivalent of the RIT-D for EDBs, i.e., as we noted above, there is no requirement for EDBs to undertake a cost benefit analysis of different options when investments are expected to exceed a certain threshold.

In other words, the only circumstances in which a network business will be compelled to *consider explicitly* non-network alternatives, such as distributed generation, is when Transpower is seeking to invest more than \$20m on one project. In these cases, it is reasonable to expect that non-network solutions will be selected when they reduce costs overall, i.e., by producing network cost savings. However, that conclusion cannot be reached so easily for smaller transmission network investments ('base capex') or for distribution network investments.

*Without any equivalents to the RIT-T and RIT-D, it is possible that networks may favour network solutions.*

Rather, the Australian experience might suggest that, in the absence of a regulatory investment test process (such as the RIT-T or RIT-D) or some other obligation to pay providers of non-network solutions (such as the distributed generation pricing principles under the current Code), that networks might be inclined to favour network solutions, even when alternatives might deliver greater benefits. At the very least, we consider that the factors set out in section 5.1.3.1, when coupled with the Australian experience, suggests that there is at least *some* risk that:

- payments to non-network providers might be limited to instances when there are *clear and substantial* benefits from adopting a non-network solution; and
- payments may not be forthcoming in other situations where the case between network and non-network solutions is more closely balanced, but where the latter is nevertheless the more cost effective option.





This risk may be particularly acute in the case of *smaller* providers of non-network solutions, such as smaller distributed generators. Because of the transaction costs involved with entering into contracts, networks may be understandably reluctant to deal with providers who may only be capable of delivering small network cost savings. However, it may be that the aggregate benefits to the network business offered by *lots* of non-network providers (such as DGs) may be significant.

Unless an aggregator steps in to consolidate those suppliers (which is quite possible), allowing the network to contract with one party, there is a risk that those potential benefits might be foregone. The alternative would be to design some form of 'negative tariff' that would be paid to all qualifying distributed generators (and potentially other suppliers of non-network solutions). However, for the reasons we set out in section 6, this would be very challenging, in practice.

For these reasons, if the reforms proposed in the Consultation Paper are implemented – and ACOT payments as we know them cease – it is possible that DGs that are delivering network cost reductions might not receive adequate compensation for those benefits from either Transpower or EDBs. The same potential risk applies to DGs that might be looking to invest in the future under the proposed arrangements.

#### 5.1.4 Summary

On the one hand, if the proposed reforms are implemented, there is good reason to think that there would be fewer instances in which DGs are being paid sums that exceed the transmission and distribution network support benefits that they are delivering. Instead, such payments are more likely to be limited to situations in which the payee is confident that there would be a genuine network cost saving, over the long-term. However, it is important to recognise that this does not necessarily represent an improvement on the status quo, because:

- the status quo *may soon change*, e.g., the TPM may change so as to address the overly strong RCPD charge that is causing much of the prevailing inefficiency – either by weakening the signal or replacing it with something else; and
- if that is the case, then it would not be necessary to remove schedule 6.4 to limit the number of instances in which DGs receive payments when there has been no transmission cost saving – the TPM reforms would deliver that outcome.

On the other hand, there is some risk that the proposal may also result in some DGs *not* being paid when they *are* providing (or could provide) network cost savings. In other words, the proposal might discourage some efficient distributed generation, in practice. If so, that would clearly come at some cost, which would serve to off-set the benefits described above (which are arguably not uniquely attributable to the proposed reform in any event).<sup>50</sup>

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<sup>50</sup> Note that we do not have a firm view on *how* likely it is that efficient investment in and use of distributed generation would be discouraged under the proposal. As noted above, it is possible



The Consultation Paper is therefore not necessarily correct to conclude that future prices would be lower and ‘more cost reflective’ under the proposed reform. Much would depend upon what happens to the TPM at the conclusion of that parallel consultation process, and how Transpower and, perhaps even more relevantly, EDBs would respond to the proposed reform, in light of the factors described above.<sup>51</sup> The Consultation Paper appears not to have given much consideration to these important practical matters.

## 5.2 Unclear effect on the level of technology neutrality

The reforms proposed in the Consultation Paper would remove the artificial advantage to DGs granted by existing ACOT payments. However, the long-term implications are difficult to predict, since it is unclear what payment arrangements would replace the status quo. The extent of technology neutrality would also be affected by whether EDBs require DGs to contribute to the common costs of the distribution network and whether transmission-connected generators would be required to pay interconnection costs under any reforms to the TPM.

### 5.2.1 Removing ACOT payments

In section 4.2, we explained that the ACOT payments made under the current arrangements represent an additional revenue stream that is available to DGs but not to transmission-connected generators, or other non-network solution (such as various forms of demand-side management). We concluded that, all other things being equal, this would make investors more inclined to favour DG when alternatives would offer greater market benefits.

*The proposal would remove a potentially distortionary source of revenue, but it is unclear what would replace it.*

As we explained above, as understand it, the proposed reform would result in all such payments ceasing. The immediate effect of the reform would consequently be to remove this potentially distortionary source of additional revenue to one particular form of technology. However, the longer-term effects of the reform on investment incentives are altogether more difficult to predict. Indeed, if the current ACOT payments are removed, that is unlikely to be the end of the matter.

Rather, as we explained in the previous section, Transpower and EDB would have to decide what, if any payments they would make to DGs – and the basis upon which those payments would be made. However, if those payments were more cost-reflective and, potentially extended to other forms of non-network solutions, then this would improve technology neutrality, other things being equal.

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that the existence of the RIT-T and RIT-D frameworks actually made no difference to the conduct of firms in Australia – or that New Zealand networks would behave differently in any event. We also offer no opinion on the likely relativity of these costs and benefits, other than to observe that the CBA in the Consultation Paper does not assess them in any robust way.

<sup>51</sup> For example, the Consultation Paper simply contends that EDBs will have “a strong incentive to move towards service-based and cost-reflective pricing structures”. See: Consultation Paper §2.7.5.



## 5.2.2 Allocating a share of common costs to DGs

In section 4.1.1, we noted that the pricing principles for distributed generation set out in the Code prevent EDBs from allocating any share of common costs to DGs. If the proposed reform is implemented, EDBs would consequently have the option of allocating a proportion of fixed distribution network costs to DGs. As we noted in section 4.1.1, in narrow terms this might, in some circumstances, be considered efficient. However, it may also effect investors' choice of technology.

In particular, if an EDB decided to allocate a share of common distribution network costs to DGs, that may make generators less inclined to embed, all other things being equal since, under the *current* TPM, transmission-connected generators do not pay interconnection charges.<sup>52</sup> If those additional costs may more than offset the ostensible bias in the connection charging regimes (described in section 4.2), then this could skew investment inefficiently towards transmission-connected plant.

*The extent of technology neutrality would also be affected by the extent to which generators must contribute to EDBs and/or Transpower's common costs.*

But, of course, as we have noted on several occasions hitherto, the current TPM is *also* under review. Under the proposed AoB charge, transmission-connected generators would be required to pay interconnection charges where they are deemed to benefit from particular investments. A final decision on whether to adopt such a charge – and the form it would take – is yet to be made. However, if generators do indeed start paying for a share of common costs of the transmission network, then this would also be factored into their choice of technology.

For example, if the sum of common transmission costs allocated to transmission-connected generators under any TPM reforms exceeds substantially any share of common distribution network costs allocated to DGs by EDBs then, all other things being equal, investors can be expected to favour the latter (and vice versa). In other words, there are a lot of 'moving parts' that may ultimately bear upon the overall degree of technology neutrality. For that reason, in our view, one consequently cannot conclude definitively that the proposed reform would represent an improvement, relative to the status quo.

## 5.2.3 Summary

In the near-term, the reforms contemplated in the Consultation Paper would serve to reduce the bias that prospective investors may currently have towards DG by removing the current ACOT payment framework. However, the long-term effect of that reform on the overall level of technology neutrality would depend upon the arrangements that ultimately replaced the status quo which, at this stage, is not straightforward to predict.

Furthermore, by potentially requiring DGs to make a contribution to EDBs' common costs, this may skew investment towards *transmission*-connected generation, all other things being equal. On the other hand, if the changes to the

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<sup>52</sup> Interconnection charges are broadly synonymous with common transmission network costs.



TPM that are proposed in the EA's second Issues Paper are implemented, and generators are required to start contributing to the common costs of the transmission network, this may off-set or reverse this effect.<sup>53</sup>

### 5.3 Unclear effect on proportionality and predictability

*We are unable to conclude whether the proposal would send more efficient signals to DGs overall, relative to the status quo.*

We concluded in section 4.3 that pricing arrangements for distributed generation, when combined with the current TPM, do not strike a particularly good balance between sending efficient price and investment signals and minimising administrative costs. Given the point of time in the investment cycle, there is unlikely to be a strong correlation between a DG receiving an ACOT payment and it giving rise to an equivalent network cost saving. The material set out in section 5.1 suggests that the proposal is likely to mean that:

- there would be fewer instances in which DGs are being paid sums that exceed the transmission and distribution network benefits that they are delivering (remembering that reforming the TPM could achieve the same outcome, regardless of whether schedule 6.4 is removed); but
- there is some risk that the proposal may also result in some DGs *not* being paid when they *are* providing (or could provide) network cost savings, e.g., because network businesses may have perfectly understandable reasons to favour network solutions.

*The proposal would be more administratively complex and difficult to predict.*

We were consequently unable to conclude whether the proposal would, in fact, send more efficient signals to DGs overall, relative to the status quo. The proposed reform would also be more administratively complex<sup>54</sup> and, by definition, more difficult to predict (since there are many ways in which Transpower and EDBs would react). Moreover, as we explain in the following sections, the very fact that such a substantial change is being contemplated – and the timing of that development – could, in itself, undermine the predictability of the regime.

#### 5.3.1 The proposed reforms could be viewed as unpredictable

When changes to the ACOT payments framework was foreshadowed in an earlier working paper<sup>55</sup> a number of submitters contended that, if implemented, this would be a significant, unexpected development. This was said to run the risk of affecting the returns that investors in DG might reasonably have anticipated, thereby:<sup>56</sup>

<sup>53</sup> Here again, the CBA set out in the Consultation Paper does not appear to take any account of these myriad complexities in any meaningful way.

<sup>54</sup> We explore some of the practical implications for Transpower in section 6.

<sup>55</sup> Electricity Authority, *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation, Working Paper*, 19 November 2013.

<sup>56</sup> See for example: NERA, *Regulatory Change Management, A report for Transpower*, January 2014.



*The Consultation Paper contends that investors should have known that ACOT payments would cease.*

- increasing the level of uncertainty and predictability in the regulatory environment; and
- increasing the level of regulatory risk, the attendant costs of operating in the industry (including the cost of capital) and, ultimately, prices for customers.

Those submissions are dismissed in the Consultation Paper on the basis that investors in distributed generation should have known that ACOT payments represented ‘windfall gains’ rather than ‘genuine transmission benefits’ and would therefore not be sustained.<sup>57</sup> The Consultation Paper consequently concludes that the proposed reform would neither represent an unpredictable development, nor give rise to any adverse impact upon investor certainty.<sup>58</sup>

We are not as convinced. In our opinion, it is not necessarily correct to suggest that investors in DGs had somehow engaged in conduct that they knew would give rise to windfall gains, but not to efficiency gains. Investors respond to the prospect of earning the greatest return. Like all rational economic agents, they respond to price signals. In our view, it is quite plausible that the distinction between ‘windfall gains’ and ‘genuine transmission benefits’ was never considered.<sup>59</sup>

Furthermore, even if investors were at least cognisant of the distinction highlighted in the Consultation Paper, it is arguably overly simplistic to suggest that they would naturally conclude that the payments would not be sustained. There is a number of potential reasons why investors could quite reasonably have held an altogether different view of the status quo, including:

*Perceptions of the status quo may have been quite different to the depiction in the Consultation Paper – and not unreasonably so.*

- the arrangements had been in place for a number of years and had been reviewed – and retained – on at least one occasion;<sup>60</sup> and
- even if an investor did perceive that there were some inefficiencies associated with the status quo (e.g., some of the factors described in section 4):
  - it may have concluded nevertheless that an ACOT payment was justified in its particular circumstances, e.g., it may have believed it was deferring transmission costs even if others were not; and
  - it may have reasoned that potential flaws can be identified in virtually *any* regulatory charging methodology,<sup>61</sup> and that this did not necessarily mean that no reliance could be placed on the status quo.

<sup>57</sup> Consultation Paper §4.5.26(b).

<sup>58</sup> Consultation Paper §4.5.27.

<sup>59</sup> Indeed, a dollar of ‘windfall gains’ represents the same return to an investor.

<sup>60</sup> For example, in 2009, the CEO Forum explored the connection charging arrangements and the working group decided against recommending any changes at that time. *See: Green et al, New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group, 29 August 2009.* This recommendation was reflected in the subsequent advice of the Transmission Pricing Advisory Group (TPAG).

<sup>61</sup> There is generally no ‘unambiguously best’ way to set prices – trade-offs often need to be made, requiring regulatory judgement. For example, it was not so long ago that long ago that the EA



This could well mean that investors' perceptions of the arrangements were very different from the way they are characterised in the Consultation Paper – and not unjustifiably so. In those circumstances, DGs – and their investors – would have some basis for saying that they were entitled to put some stock in the status quo when deploying capital. Moreover, it begs the rather obvious question: what other existing regulations overseen by the EA cannot be relied upon by investors?

For those reasons, the Consultation Paper is too swift to dismiss the possibility that the proposed reform might have adverse impacts upon investor certainty. In our view, it may. Moreover, the same potential effects could arise in respect of *any* proposal that served to reduce significantly returns from existing DG assets, e.g., if schedule 6.4 remained in place, but the TPM was reformed in a way that led to large reductions in ACOT payments.

*The key question is whether ACOT payments formed an important factor in DG's decision making.*

However, economic costs would not follow as a matter of course. The magnitude of any adverse impacts on investor certainty is instead likely to depend critically upon the extent that ACOT payments (or other payments from EBDs<sup>62</sup>) formed a key factor in DG's investment and operating decisions. And similarly, in the case of reforms to the TPM that would retain ACOT payments, but reduce their magnitude, the key question would be whether the *size* of the expected payment was pivotal.

If DGs' investments or operating decisions *have* hinged upon a legitimate expectation of receiving an ongoing stream of ACOT payments, then there is the potential for the proposed reform to compromise investor confidence. Conversely, if ACOT payments (of any level) *have not* been a key factor in DG's investment and operating decisions, or if the investments in question pre-date the existing arrangements, then these concerns largely fall away.<sup>63</sup>

### **5.3.2 The proposed reforms risk existing DGs being 'held up'**

The reforms proposed in the Consultation Paper and, more generally, any change to the TPM that would reduce the ACOT payments received by existing DGs, give rise to two potential forms of 'hold-up' that may undermine investor confidence. Hold-up occurs when one party to an agreement incurs costs that cannot be recouped, only for another party to exploit that fact. A commonly cited example of hold-up is when a regulator is tempted to ignore sunk costs during the price setting process,

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thought that its proposed 'SPD methodology' represented the most efficient approach to transmission pricing. However, it has since abandoned that proposal.

<sup>62</sup> Recall that not all EBDs base their payments to DGs on avoided transmission charges.

<sup>63</sup> In those circumstances the Consultation Paper would have some justification in characterising any reform as simply removing a windfall gain to DGs that was not necessary for them to invest in the first place and has no impact on their operational decisions.



since the revenues required for the regulated business to remain viable in the short-term do not need not provide a return on past investments.<sup>64</sup>

Of course, it is not in the overall interests of the regulator to engage in this type of opportunistic conduct, since it can be expected to have an adverse effect on firms' incentives to invest. Having being held-up once, the regulated suppliers may foresee that they would not gain an adequate return on future investments either, and decline to invest, even if that would be efficient.

As we explain in the following sections, there are two potential types of existing DGs that may fall into this category if the proposed reforms are implemented. It is worth noting also that, although the analysis in the following sections focuses on the effects of the proposal in the Consultation Paper, it would apply equally to any reform to the TPM that led to a significant decrease in ACOT payments, e.g., if the existing RCPD charge was modified or replaced with, say, an LRMC charge.

### **5.3.2.1 DGs that are delivering benefits now**

The proposal set out in the Consultation Paper contemplates Transpower and EDBs entering into contracts with both prospective investors in distributed generation ('new DGs') and existing DGs. It is relatively straightforward to imagine how this might work for new DGs – at least in principle (as we explain in section 6.3, there would be a number of practical challenges). For example:<sup>65</sup>

- Transpower might ask: 'if this DG locates in this place and at this time and operates as intended, would it reduce my forward-looking costs?';<sup>66</sup> and
- if the answer is 'yes', the two parties may have a mutual incentive to enter into a contract for the provision of network support; and
- Transpower can be expected to pay a price for that network support that is less than or equal to the NPV of any network deferral benefits.

It is not so straightforward to envisage how this would play out with existing DGs. In the previous example, the DG in question was yet to invest. An existing DG is at a distinct disadvantage, because it has already sunk costs. A key question, therefore, is whether businesses should take this into account when deciding whether to contract with those parties. For example, there are two broad types of hypothetical questions that an EDB or Transpower might reasonably ask:

*An existing DG may be delivering network support benefits, but the business may know that it does not have to pay for them.*

<sup>64</sup> For a more comprehensive discussion of 'hold-up' problems and regulatory opportunism, see: Green *et al*, *Alternative Approaches to Light-handed Regulation, A Report for the Essential Services Commission*, 5 March 2004, §4.3.

<sup>65</sup> In section 6.3 we explore in more details the various ways in which Transpower might go about contracting with DGs.

<sup>66</sup> Note that these forward-looking costs would also include the costs of negotiating and transacting with the DG. If the network deferral benefits are very small – but still positive – these transaction costs may be the 'swing factor' in the decision.



- “if this DG was not here, would my forward-looking costs increase?”, i.e., undertake some form of ‘with and without the DG’ test; or
- “if I do not give the DG some form of payment (given that the ACOT payments are ceasing), would my forward-looking costs increase?”, i.e., a ‘with and without a network support payment’ test?

These hypothetical questions might appear similar, but there is a critical difference that means that the answer to the first question could be ‘yes’, but the answer to the second ‘no’. This could happen when the existence of a DG was indeed allowing a business to avoid network costs (resulting in an affirmative answer to the first question), but when the provision of that network support was no longer dependent upon the DG receiving a payment for it.

Specifically, having already invested and ‘sunk’ costs, the DG might be unlikely to exit – or materially modify its behaviour – if it ceased receiving ACOT payments. In those circumstances, an EDB or Transpower could continue to receive the same network support benefits without having to pay anything for them. On its face, this would appear to be a classic example of ‘hold up’ that has the potential to compromise investor confidence.

However, this problem does not have a straightforward solution. This is because, although it is possible for a network business to answer the second ‘hypothetical’ question set out above, there is no clear answer to the first. To see why, imagine a business was seeking to answer the first hypothetical question by ‘notionally removing’ individual DGs and considering the potential impacts on its forward-looking costs. All sorts of counterintuitive results are possible, for example:

- where there is a large number of small existing DGs, the business might conclude that none of them are *individually* giving rise to network cost savings – which might be true, but could miss the fact that *collectively* they were giving rise to material benefits; and
- similarly, where there is a small number of large DGs, the business might conclude that they are *all individually* allowing it to defer a transmission upgrade when, in fact, that might only be made possible in each case by the fact that the other DGs are also in place, i.e., they would not *each* be delivering, say, a \$1m benefit – they might be doing so *collectively*.

*Avoiding these hold-up problems would be like trying to ‘unscramble an egg’, i.e., not practicable.*

In other words, in the first example the benefits being provided by the DGs would be under-stated and, in the second scenario they would over-stated. In our view, there is really no way to conduct this sort of exercise in a way that avoids giving rise to these anomalous results, e.g., there is no obvious way to group existing DGs together into appropriate sub-sets so as to consider their impacts. To put it colloquially, this would be like trying to ‘unscramble an egg’.

It follows that, if the proposed reform is implemented, it is likely that EDBs and Transpower would be forced, in practice, to ask themselves the *second* question when contracting with existing DGs. This also appears to be what it envisaged in the





Consultation Paper, which refers to the fact that Transpower would need to: “assess the effect of removing some existing *ACOT payments*, which could affect transmission needs in some regions”<sup>67</sup> (our emphasis).

*DGs would have to deal with a monopsony buyer of network support services.*

Furthermore, even if it *would* be worthwhile for Transpower to continue to pay an existing generator so that it continues to provide network support, it does not follow that it has to pay a price that reflects the *full value* of that support – or potentially anything close to it. All that it would have to do is pay a DG a price that exceeds the *incremental cost* that it would incur in providing the network support services. But that may be *well below* the value that Transpower obtains from the DG.

In other words, by removing completely any pricing principles – e.g., a clear requirement that payments reflect the ‘avoided costs’ – the proposal would leave DGs to deal with a monopsonist with substantial buying power. As we explain in more detail in section 6.3.1.1, it could be that larger DGs would have a significant degree of countervailing power and could negotiate reasonable terms and conditions with Transpower.

*The proposal would create substantial market power problems.*

However, smaller DGs would be entirely reliant upon Transpower’s benevolence. If it was inclined to maximise the returns of its shareholders (which is, after all, its principal corporate objective) it would be in a very powerful position to procure any network support services that it needed, without sharing very much – if *any* – of the margin between marginal cost and marginal benefit with those DGs. This is not possible under the status quo, because there is a guiding pricing principle in schedule 6.4, which prevents it.

The Consultation Paper appears not to have given any consideration at all to the potential market power issues that would be created if the existing regulatory principle was removed. In particular, although the Consultation Paper has rightly observed that Transpower would have efficient incentives to procure network support where it would save costs, it has not recognised that, in the absence of any constraining regulatory principles, it would have little or no incentive to pay DGs a ‘fair’ price for those services.

All of the factors set out above have the potential to lead to significant market power problems and hold-up, with attendant adverse effects on investor confidence. Moreover, scope for hold-up is not limited to those existing DGs who are currently delivering benefits. There may also be adverse consequences for generators that have provided network cost savings to EBDs and/or to Transpower in the past, but are no longer doing so (or not to the same extent) given the point of time in the investment cycle.

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<sup>67</sup> Consultation Paper §4.2.27(a).



### 5.3.2.2 DGs that have delivered benefits in the past

The proposed reform comes hard on the heels of Transpower investing approximately \$2b, which has created spare capacity throughout much of the grid. This will undoubtedly have affected the extent to which existing DGs would be assessed as delivering future transmission network cost savings, if such an inquiry was made today. This is a consequence of the 'saw-tooth' pattern depicted earlier in Figure 2.1; namely:

- prior to Transpower's \$2b investment programme, the LRMC of transmission is likely to have been relatively high – reflecting the significant benefits that could have been obtained by deferring some of those works; and
- now that those upgrades have been completed (for the most part), there is spare transmission capacity and LRMC can be expected to be much lower throughout much of the grid, on average.

Put another way, in recent times, the LRMC of transmission – and the value of network costs that can potentially be avoided through distributed generation – is likely to have fallen from a 'peak' to a 'trough'. It is therefore reasonable to expect that, if payments from Transpower to existing DGs were based on the extent to which they are avoiding network costs *now*, those payments may be infrequent, and much lower than they would have been under the status quo.

*DGs may have delivered savings in the past that exceeded the ACOT payments that they have received and any payments that they would receive from Transpower now.*

That is not necessarily a bad thing in the case of DGs that were *never* delivering transmission network support benefits,<sup>68</sup> subject to the qualifications set out in section 5.3.1. However, it could be problematic in the case of DGs that *have* delivered network cost savings in the past, but are no longer doing so – or at least, not to the same extent. For example, it is conceivable that:

- a DG was exporting to an area in which Transpower has recently upgraded the grid, and the existence of that plant might have meant that those upgrades occurred later than would otherwise have been the case; and
- although that DG would have received ACOT payments, they may have been considerably less in aggregate than the NPV of the deferral benefit it delivered to Transpower, i.e., the long-run avoided cost; and
- the amount that Transpower would be willing to pay it now under the proposed reform (if anything) may be even less than the RCPD-based ACOT payments that it had been receiving previously.

If that was indeed the case, then the affected DGs would have some basis for saying that the proposal would also result in *them* being held up. Specifically, they could justifiably take umbrage at the fact that the reform was being proposed now, when the potential for transmission network cost savings is now much diminished, when

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<sup>68</sup> Or if the DGs were delivering benefits that were less than the ACOT payments received from EDBs – see section 3.1.



those businesses perhaps did not receive the high prices that Transpower might have been willing to pay not so long ago.

*Existing DGs could argue that the timing of the proposal is opportunistic.*

Put another way, referring back to Figure 2.1., existing DGs could argue that the proposed reform would involve them getting the 'trough', when they had not received the 'peak'. This might be seen as unfairly 'shifting the goal posts', and may serve to compromise investor confidence and certainty. However, for the same reasons as we set out above, there is unlikely to be a workable solution to this problem, in practice, i.e., no way to 'unscramble the egg'.

A similar story applies to DGs that may have given rise to *distribution* network cost savings in the past, but which may no longer be doing so today (or not to the same extent). For example, it is possible that there may be DGs that did not give rise to past *transmission* network cost savings, but *did* give rise to distribution network support benefits, which outweighed any ACOT payments that they received. This is the same scenario as described above – but this time for distribution.

If EDBs declined to pay existing DGs, or reduced substantially those payments from what they are now to reflect any reduced scope for the avoidance of network costs, then this might again be seen as opportunistic. However, for the reasons that we set out above, there would again be no easy way for EDBs to work out which DGs have been 'under-compensated' for historical distribution network support benefits through past ACOT payments, so as to 'make good'.<sup>69</sup>

Finally, it is worth emphasising that the magnitude of any adverse impacts arising from the potential hold-up problems described above (and in the previous section) would depend upon the extent that ACOT payments (or other payments from EDBs) formed a key factor in existing DG's investment and operating decisions. If the prospect of receiving a stream of payments (of any level) *has not* been a key factor in existing DGs' investment and operating decisions, or if investments pre-date the existing arrangements, then the potential economic costs diminish considerably, or disappear altogether.

### 5.3.3 Summary

We are unable to reach a firm conclusion on whether the proposed reform would be more proportional and predictable than the status quo. For the reasons set out in section 5.1, it is unclear whether the proposal would send more efficient signals to DGs overall, relative to the status quo. Although there would be likely to be fewer instances of DGs being rewarded when they do not deliver network benefits, there may be more instances of DGs *not* being appropriately compensated when they do.

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<sup>69</sup> Or through other forms of payments from EDBs – remembering that not all of the businesses base their payments on avoided transmission charges.



What is clear is that the proposed reform would also be more administratively complex and more difficult to predict than the status quo.<sup>70</sup> The very fact that substantial change is being contemplated could, in itself, also serve to undermine the predictability of the regime. There would also be the clear potential for existing DGs who have provided network support benefits in the past – or are doing so today – to be ‘held-up’ if the suggested reforms are implemented.

The Consultation Paper also overlooks the incentives that Transpower would have when procuring network support. Although it rightly observes that Transpower would have efficient incentives to procure network support where it would save costs, it has not recognised that, in the absence of any guiding regulatory principle, it would have little or no incentive to pay DGs a ‘fair’ price for those services. This represents a significant shortcoming in the analysis.

The extent to which these factors undermine investor confidence and certainty in practice hinges to a large degree upon the extent that ACOT payments (or other payments from EDBs) formed a key factor in existing DG’s decision making. If they did not – e.g., because the investments in question were made before the existing pricing principles were in place – then any economic costs arising from the above factors are likely to diminish or disappear.

## 5.4 Unclear effect on symmetry

We explained in section 4.4 that, in principle at least, EDBs can charge DGs more when they give rise to the additional types of costs described in section 2.2.3. We also described some of the practical challenges that may be associated with attempting to do so. The proposed reforms would not appear to have any material bearing on the incentive of firms to charge DGs more when they give rise to additional costs – and the same practical obstacles would remain.

The proposal would, however, address the potential asymmetry under the status quo in which DGs may be remunerated with ACOT payments that often overstate the network benefits that they have delivered, if any. But as we have explained at length above, this may come at the expense of another asymmetry, i.e., the possibility that some DGs would not be paid sums by networks that reflect the full extent of the network cost savings that they have delivered.

## 5.5 Summary

Table 5.1 summarises our evaluation of reforms proposed in the Consultation Paper against each of the four overarching objectives described in section 3, by reference to the status quo. It highlights a number of areas where those changes are likely to represent an improvement over the existing arrangements, as well as a number of other aspects that have the potential to be problematic.

*The proposal may address some source of asymmetry but introduce others.*

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<sup>70</sup> By definition, market participants will be more familiar with the status quo.



**Table 5.1: Assessment of proposed reforms**

Overarching objective	Performance of the proposed reforms
<p><b>Cost minimisation and reflectivity</b></p>	<p>There would be fewer instances of DGs receiving payments from networks when they are not delivering (or would not deliver) network cost savings. However, this is not necessarily a benefit of the proposal, <i>per se</i>, since the same outcome could be achieved through TPM reform.</p> <p>There would also be more instances of DGs delivering network benefits (or having the potential to do so), yet not receiving payments from networks that reflect the value of those benefits.</p> <p>It follows that the conclusion in the Consultation Paper that future prices would be lower and more cost reflective under the proposed reform is not necessarily correct. It depends upon the relativities of the costs and benefits, described above (upon which we have no firm view).</p>
<p><b>Technology neutrality</b></p>	<p>The proposed reforms would remove the artificial advantage to DG granted by existing ACOT payments. However, the long-term implications are difficult to predict, since it is unclear what payment arrangements would replace the status quo.</p> <p>The extent of technology neutrality would also be affected by whether EDBs require DGs to contribute to the common costs of the distribution network and whether transmission-connected generators would be required to pay interconnection costs under any reforms to the TPM.</p> <p>For that reason, in our view, one consequently cannot conclude definitively that the proposed reform would be more ‘technology neutral’, relative to the status quo.</p>
<p><b>Proportional and predictable</b></p>	<p>As noted above, it is unclear whether the proposal would send more efficient price signals to DGs overall. What is clear is that the proposed reform would be more administratively complex and more difficult to predict than the status quo.</p> <p>The very fact that substantial change is being considered could also serve to undermine the predictability of the regime. There is also the clear potential for existing DGs who have provided network support benefits in the past – or are doing so today – to be ‘held-up’, which may further harm investor confidence.</p> <p>If the prospect of receiving a stream of payments from networks <i>has not</i> been a key factor in existing DGs’ investment and operating decisions, or if investments pre-date the existing arrangements, then these concerns largely fall away.</p> <p>However, the proposal would still create substantial market power problems, where DGs would have to sell network support services to a monopsony buyer, without any constraining pricing principles.</p>



Overarching objective	Performance of the proposed reforms
<b>Symmetry of costs and benefits</b>	Like the status quo, the proposed reforms would allow for at least some symmetry in the treatment of benefits and costs in that EDBs can, in principle, charge DGs for any incremental costs they impose upon their networks. There would also be fewer instances of DGs receiving payments from networks that exceed the benefits they are delivering. However, there may be more instances of DGs not being compensated appropriately when they can enable networks to avoid long-term costs.

On the basis of the observations Table 5.1, we consider that it is unclear whether the proposed reforms would represent a material improvement upon the current pricing arrangements for distributed generation. If the TPM is reformed so as to reduce the incidence of DGs receiving ACOT payments when there has been no reduction in transmission costs, then that arguably removes the primary reason for removing schedule 6.4.

Any TPM reforms may also have a significant bearing upon the degree of technology neutrality – an interdependence that the Consultation Paper appears not to have appreciated. Moreover, removing the pricing principles in schedule 6.4 (and not replacing them with anything else) and leaving the procurement of network support more less entirely to Transpower, would create a rather obvious market power problem.

Although Transpower would have efficient incentives to procure network support where it would save costs, in the absence of any guiding regulatory principle, it would have little or no incentive to pay DGs a fair price for those services. Smaller DGs in particular could find themselves receiving prices that reflected little more than the incremental cost of providing network support, which may be much lower than the value they are adding.

The Consultation Paper does not include a sufficiently thorough consideration of these matters – either qualitative or quantitative.<sup>71</sup> There would consequently be a high risk of unintended consequences if the reforms were implemented as proposed. In our view, given that any reform to the TPM would have a potentially large bearing on the benefits and costs of reforming the pricing principles for DGs, it would be better to eschew from making any decisions on the latter, until a position has been reached on the former.

<sup>71</sup> As we noted earlier, the CBA set out in the Consultation Paper does not take any account of these myriad complexities in any meaningful way. Its conclusions also rest on a large number of unsubstantiated assumptions. It therefore does not constitute a sound empirical illustration of the purported benefits of the proposed reform.



## 6. Practical challenges for Transpower

In this section we highlight in more detail the practical challenges that Transpower would face if it takes on the broader role of contracting with DGs that is envisaged in the Consultation Paper. For the purposes of this section, we have assumed that the proposal is implemented ‘as is’, i.e., we have not considered the potential consequences if, say, the TPM was reformed and schedule 6.4 was retained.

The most obvious immediate consequence is that Transpower would face higher administrative costs, transacting with a larger number of parties. There would also be important questions of implementation for it to consider, including which DGs to contract with and on what terms. The proposed reforms may also test the existing planning and investment frameworks.

### 6.1 Higher transaction costs

As we explained in section 5.1.3.2 (and set out in more detail in Appendix A), there is a number of ways in which Transpower engages with providers of non-network solutions at present. Most notably, whenever it proposes to build something that is expected to cost more than \$20m, it must consider explicitly non-network alternatives under its major capex framework. It also operates a demand response programme, for which it receives funding under its revenue cap.<sup>72</sup>

More generally, Transpower is permitted to utilise non-network solutions such as distributed generation and other forms of demand response as alternatives to *all* forms of network expenditure – including its base capex, provided it can still meet the relevant service standards. In other words, in *principle*, there is nothing stopping DGs from approaching Transpower right now. Of course, in *practice*, there is an obvious reason why many would not.

And that is the fact that, at present, DGs have the option of receiving a payment from an EDB that, in most cases, reflects avoided transmission charges. When faced with the option of negotiating a bespoke contract with Transpower and receiving ACOT payments from an EDB, there are some compelling reasons why an EDB might opt for the latter, including:

- even if the DG was not actually allowing transmission costs to be avoided, it might still allow the EDB to avoid transmission charges, i.e., it may receive a payment from the EDB when it would not have from Transpower;
- even if the DG was going to defer transmission costs, it might still prefer to receive ACOT payments from an EDB, either because:

*If the proposed reforms are implemented, more DGs are likely to approach Transpower, seeking payments for network support.*

<sup>72</sup> Recall that it has been granted an opex allowance of \$8m over 2015-20 to fund the programme. See: Commerce Commission, *Setting Transpower’s individual price-quality path for 2015 – 2020*, [2014] NZCC 23, §5.183.



- it considered that they would be bigger in aggregate than any payments it might receive from Transpower; and/or
- it preferred the ‘time-profile’ of expected ACOT payments, i.e., they would extend into the future, regardless of whether constraints existed;<sup>73</sup> and
- the DG may also be less inclined to negotiate a bespoke contract with Transpower when it has the option of receiving a payment from its EDB, via what is likely to be a more familiar – and perhaps less costly process.

*The extent of any increase in transaction costs would depend upon how Transpower chooses to respond to any such reforms.*

If the option of receiving ACOT payments is taken away – or, if it becomes less attractive as a result of any reforms to the TPM<sup>74</sup> – then there will be DGs who would have dealt exclusively with their EDBs under the status quo, that will instead turn their attention to Transpower. In other words, Transpower can expect to receive an ‘increase in volume’, as DGs approach it for payment. This would naturally give rise to an increase in administration costs.

The extent of that increase in transaction costs would depend to a significant extent upon how Transpower decides to go about engaging and contracting with DGs – and potentially other providers of non-network solutions. First and foremost, there is the question about how to deal with DGs that are already in place. There are then more general questions to consider around deciding which DGs to contract with and on what terms. We explore these matters below.

## 6.2 How to deal with existing DGs?

The proposal set out in the Consultation Paper contemplates Transpower entering into contracts with DGs ‘to develop and/or operate distributed generation that avoids transmission network costs, to the extent this is efficient.’<sup>75</sup> This is a relatively straightforward concept to implement for prospective DGs – at least in principle (we explore some of the practical challenges in the following section). However, things are not so simple when it comes to DGs that exist already.

The only practicable way for Transpower to identify those existing DGs with which it should contract for the provision of network support services is to ask some variant of the following question: “if I do not make a payment, would my forward-

<sup>73</sup> Specifically, Transpower would presumably be most interested in paying DGs – and other non-network providers – for network support when constraints are emerging. However, all other things being equal, a DG can allow an EDB to reduce its RCPD-based interconnection charge *at any time*, regardless of the relativity of RCPD and network capacity, e.g., if RCPD is only 50% of the available transmission network capacity, this does not affect the ACOT payment.

<sup>74</sup> For example, if the AoB charge proposed by in the second TPM Issues Paper is implemented, it would become much harder for EDBs to work out whether a DG is allowing it to avoid transmission charges. It follows that, if this was to be retained as a methodology by some EDBs if the proposed changes to the TPM are implemented (or something like them), then it is unlikely to be especially appealing to DGs relative to the status quo.

<sup>75</sup> Consultation Paper, §4.2.16(a).





looking costs increase?” For the reasons we set out at length in section 5.3.2, this approach brings with it a risk of some existing DGs being ‘held up’, since:

- some DGs may currently be providing Transpower with network support services, but it may know that it does not have to pay for them, i.e., because a DG has sunk its costs, and would remain in place irrespective of whether it receives any additional payments; and
- some DGs may not be delivering material benefits to Transpower now, but they may have allowed it to defer substantial network costs in the past – and not been compensated sufficiently for those benefits through the ACOT payments they have received from their EDBs hitherto.

There is unlikely to be anything that Transpower can do to mitigate the prospect of ‘hold-up’ since, as we explained earlier, there is no easy way to ‘unwind’ these impacts. Any potential costs in terms of harm to ongoing investor confidence would then depend upon whether existing DGs’ decisions had hinged upon ACOT payments. If they did not – e.g., because investments were made before the status quo was in place – then those costs may be trivial, or zero.

### 6.3 Case-by-case approach or upfront terms?

*There are two broad approaches that Transpower could take to contracting with DGs for network support.*

In deciding how to go about contracting with DGs – both existing or new – Transpower would also have to consider whether it would do so on a pure ‘case-by-case’ basis, or whether it might endeavour to set out some price and/or non-price terms in advance. Each approach offers advantages and disadvantages, and it may even be feasible for Transpower to implement elements of both. We explore each of these approaches below, including a potential ‘hybrid’ methodology.

#### 6.3.1 Pure ‘case-by-case’ approach

Transpower might decide that it was going to approach every case on its own merits. For example, there might be no formal *ex-ante* criteria that said that a particular type of DG that invested in a particular location at a particular time would be entitled to receive a particular price. Transpower might instead look at the particular circumstances of each case and determine whether the DG in question would give rise to network cost savings; specifically:

- Transpower could ask: ‘would a DG located in this place and at this time, operating as intended, reduce my forward-looking costs?’;<sup>76</sup> and
- if the answer is ‘yes’, the two parties would then have a mutual incentive to enter into a contract for the provision of network support; and
- Transpower would then be expected to pay a price for that network support that is less than or equal to the NPV of any network deferral benefits.

<sup>76</sup> Note that these forward-looking costs would also include the costs of negotiating and transacting with the DG. If the network deferral benefits are very small – but still positive – these transaction costs may be the ‘swing factor’ in the decision.



Each contract would therefore be unique, in that the payment would reflect the network support benefits that the particular DG in question was delivering – rather than some form of average. Moreover, there would be no reason to limit the application of this approach to DGs – it could be extended to *all* potential providers of non-network solutions. As section 5.1.3.2 and Appendix A explain, Transpower is already required to adopt this approach when contemplating major capex projects.

### 6.3.1.1 Larger DGs

In our opinion, this ‘case-by-case’ approach can be expected to work best when ‘larger’ DGs are negotiating with Transpower. In these instances, it is likely to be more straightforward to work out the impact that particular increment of generation capacity would have on forward-looking network requirements. And the fact that the DG is larger means it may also be better-placed to negotiate a price for that network support. In other words, larger DGs are more likely to be able to ‘stand on their own two feet’, as it were.

Indeed, for the reasons set out in section 5.3.2, this is a particularly important consideration. As it stands, the proposal would require DGs to negotiate with a monopsony purchaser of network solutions – Transpower – without any ‘safety net’ in the form of regulatory pricing principles. In our opinion, such an arrangement would make most sense from a regulatory design perspective if Transpower was negotiating with ‘large’ DGs with some countervailing bargaining power.

*A ‘case-by-case’ approach is likely to work best for ‘larger’ DGs.*

Of course, the key question is: how large is ‘large’? There is no precise answer to this question, but some useful guidance might be obtained from the Essential Services Commission of Victoria (‘ESC’). Late last year, the ESC was tasked by the Victorian Government with estimating ‘the true value of distributed generation’.<sup>77</sup> The purpose of the inquiry is to ensure that DGs in Victoria are compensated for all of the benefits that they provide – including the ‘energy value’ (i.e., wholesale price reductions) and network support (which we have been discussing hitherto).

Despite ostensibly being asked to examine the value of *all* distributed generation, the ESC has decided to look only at DGs smaller than 5MW.<sup>78</sup> We presume that the reason the ESC has chosen to focus on DGs below this threshold is because it believes that larger generators can already receive ‘true value’ of any benefits they offer – including to network businesses. This is also consistent with the sentiments expressed in a recent rule change proposal presented to the AEMC.

If implemented as proposed, the rule change would require EDBs to pay DGs a ‘local generation network credit’ (‘LGNC’), based on an estimate of the value of any

<sup>77</sup> The terms of reference for the inquiry are available [here](#).

<sup>78</sup> Essential Services Commission, *Inquiry into the True Value of Distributed Generation, Our Proposed Approach*, December 2015, p.12. Available [here](#).



network cost savings.<sup>79</sup> The proponents of the rule change contend that its purpose (which we discuss in more detail subsequently) is to address a perceived gap in the NER in relation to the treatment of *smaller* DGs. They acknowledge that the current NER “may facilitate efficient investment in larger-scale embedded generation”.<sup>80</sup>

In other words, there is good reason to be confident that, when it comes to ‘bigger’ providers, a case-by-case approach is likely to produce relatively efficient investment in and use of distributed generation – and other non-network solutions. However, as we foreshadowed in section 5.1.3, it is rather less clear whether the same can be said for ‘smaller’ DGs. As we explain below, there is some reason to think that these providers may be under-compensated if the proposed reform is implemented.

### 6.3.1.2 *Smaller DGs*

We noted in section 5.1.3 that, in Australia, most (if not all) investments in non-network solutions (including DG) had arisen out of RIT-D or RIT-T processes. These investment tests are only applied when a business is contemplating a ‘large’ investment (at least A\$5m) and so, by definition, they can only attract ‘large’ providers of non-network solutions, e.g., ‘big’ DGs.<sup>81</sup> Moreover, from a practical perspective, a network business may be understandably less inclined to enter into bespoke network support contracts with smaller DGs because:

- it may be more difficult to work out the benefits that a smaller generating unit is offering in terms of network support; and
- any benefits are likely to be much smaller than those on offer from ‘larger’ DGs, and may be outweighed by the transaction costs of entering into a contract.<sup>82</sup>

*A ‘case-by-case’ approach may not work as well for ‘smaller’ DGs.*

In other words, there is good reason to think there is ‘diminishing returns to scale’ when it comes to entering into bespoke contracts with DGs. For those reasons, unless smaller DGs are able to combine their output in some way (e.g., through an external aggregator creating a portfolio<sup>83</sup>), there could conceivably be underinvestment in and inefficient usage by smaller embedded plants. To be clear, Transpower would not need to be acting irrationally or inappropriately for this scenario to eventuate under the proposed reform.

<sup>79</sup> Oakley Greenwood, ‘Local Generation Network Credit Rule Change Proposal’, Submission to: Australian Energy Market Commission, Proposed by: City of Sydney, Total Environment Centre, Property Council of Australia, 14 July 2015. Available [here](#).

<sup>80</sup> Op. cit., p.15.

<sup>81</sup> Or, alternatively, aggregators who have created a portfolio of smaller generators or demand-side management options.

<sup>82</sup> This is one of the chief contentions made by the proponents of the LGNC rule change request mentioned earlier. They claim that network support payments are not accessible, in practice, to *smaller* DGs, because the benefits on offer to networks will almost always be outweighed by the transaction costs of entering into contracts.

<sup>83</sup> We note that there are currently businesses in Australia offering such aggregation services, such as Reposit Power. See: <http://www.repositpower.com/>.



Rather, the practical issues described above – i.e., the greater difficulty assessing benefits, and the relativity of those benefits to the transaction costs of entering bespoke contracts --may mean that Transpower is understandably less inclined to deal with smaller participants on a case-by-case basis. It may instead draw a line – even if only implicitly – and decide to focus instead on the ‘low hanging fruit’ offered by larger DGs. As we explained in section 5.1.3.4, a potential implication of this could be inefficient investment in and use of smaller DGs.

Furthermore, even if Transpower was inclined to enter into one-one-one negotiations with smaller DGs to procure network support, those parties would again find themselves dealing with an monopsonist with very strong buying power. For the reasons set out in section 5.3.2, smaller DGs may be forced to accept payments that are considerably less than the value of the network support that they are offering, e.g., closer to the incremental cost of providing it.

If Transpower was indeed to come to the view that a pure ‘case-by-case’ approach would not work well, in practice, for ‘smaller DGs’ (however defined) it would then have two broad options at its disposal. The first would be to simply retain that approach in all instance – and accept that there would sometimes be efficiency losses. The second would be to move away from a case-by-case approach – at least in some circumstances – and seek to define some *ex-ante* criteria that can be applied without having to incur the transaction costs described above.

### **6.3.2 Terms and conditions specified upfront**

We explained in section 2.2 that the potential benefits that any particular DG would offer Transpower (or an EDB) would vary from case-to-case. However, it is unlikely to be practicable for Transpower to make a unique assessment in each and every case. Nevertheless, it may still be possible to define some upfront criteria that could be applied when transaction costs render bespoke assessments impracticable, e.g., when the benefits on offer are comparatively small (as they would often be with smaller DGs).

For example, it may be possible to specify in advance some eligibility criteria that would serve to exclude DGs that are unlikely to give rise to network cost savings, thereby ‘narrowing in’ on those plants that would genuinely deliver benefits. It may also be feasible to arrive at a broad estimate of the benefits that those DGs might deliver, without going to the next step of exploring the precise magnitude of benefits in each case.

For the purposes of this analysis, we have assumed that Transpower would not seek to exercise its substantial market power when dealing with smaller DGs which, for the reasons set out above, it could if it was so inclined. Instead, we have tried to set out an approach that, if implemented, might obviate the need for explicit regulatory pricing principles. As we explain below, this may well involve paying smaller DGs more than just their incremental costs.



### 6.3.2.1 Eligibility criteria

In general terms, distributed generation can offer a clear benefit to Transpower where there is a pending need to invest in new transmission network capacity, and suitably located embedded plant of sufficient capacity and reliability is able to defer or down-size that investment. From this general principle, it is possible to distil two key criteria that could be used to determine which DGs might be eligible for a network support payment; namely:

*It may be possible to define up-front criteria that enable Transpower to 'narrow in' on those DGs that are likely to deliver benefits.*

- the DG would have to be locating in the right place, i.e., Transpower might only offer such payments to generators embedded (or embedding) where there are near-term network constraints (see the discussion of price, below); and
- the DG may have to be capable of generating reliably during peak periods (i.e., offer 'firm capacity'), which might mean that intermittent forms of generation receive lower payments,<sup>84</sup> or are ineligible to receive any remuneration.

To be clear, 'larger' DGs (however defined) might still be assessed using the 'case-by-case' approach described in section 6.3.1.1. However, if other smaller DGs met these criteria (however specified), they would *also* be eligible to receive a payment from Transpower.<sup>85</sup> The key difference would then be that this payment would not be negotiated on a bespoke basis – it would be specified upfront and, consequently, *averaged* in some way. We explain further below.

### 6.3.2.2 Estimate of average network support benefits

In order to arrive at an up-front price (e.g., per kWh) to pay to DGs that meet the qualifying criteria, it is likely to be necessary to produce an estimate of the long-run, forward-looking costs of the transmission network, i.e., the LRMC of future transmission capacity. This would then provide an indication of the costs that could potentially be avoided by a DG (and other non-network solutions). DGs might simply then be paid the 'inverse' of the LRMC, i.e., the long-run *avoided* cost.

Note that this is the methodology that was suggested in the LGNC rule change proposal mentioned earlier. Specifically, the proponents recommended that any export tariff be linked to the LRMC charges that EDBs in Australia are required to set for the *consumption* of distribution services. However, one of the biggest potential problems with this approach is that the LRMC charges that have been proposed in Australia hitherto are *highly averaged*.

<sup>84</sup> For example, in the United Kingdom, generators are paid 'negative tariffs' for energy injected into the grid during specified peak periods. However, these tariffs are considerably lower for intermittent forms of generation. For a more detailed description of the UK arrangements, see: Frontier Economics, *Valuing the impact of local generation on electricity networks, A report prepared for the Energy Networks Association (ENA)*, February 2015, Appendix B. Available [here](#).

<sup>85</sup> Note that payments to larger DGs might also be determined by reference to these upfront criteria but, in our view, that is likely to be less efficient, overall.



For example, the Victorian EDBs have each come up with a *single* LRMC estimate for each of their network areas. As the AEMC highlights in its Consultation Paper,<sup>86</sup> the trouble with using such a broad LRMC estimate as the basis for a payment for network support is that it would be inaccurate in almost every instance. The same situation would arise if Transpower was to base any of its own 'upfront' prices on highly averaged LRMC estimates, e.g., a single estimate for the whole of New Zealand.

To illustrate, suppose for the sake of illustration that Transpower's network was made up of only two areas. Suppose that, in location A, there is an imminent need for new network capacity and so the potential long-run cost savings from DGs investing in this area are high. However, imagine that, in location B, network capacity is ample, and so the potential benefits are minimal.

*In arriving at an up-front price, Transpower would face a trade-off between accuracy and simplicity.*

If Transpower was to undertake two LRMC calculations – for locations A and B, respectively – and define a separate up-front price for qualifying DGs in each area, then those in location A would be paid more. Conversely, if Transpower makes a single 'average' LRMC calculation for its whole network, such that DGs receive the same price regardless of where they locate, then:

- the price paid to customers in location A would under-signal the potential long-run network cost savings, and may lead to too little investment by DGs; and
- the price paid to customers in location B would over-signal the potential benefits, and lead to over-investment by DGs.

The overall effect may be that Transpower cannot defer or downsize the network investment in location A. That is, it would not achieve the savings that a more 'granular' LRMC-based price would offer. The upshot may be that total costs increase, and prices to end consumers consequently rise. But, on the other hand, if calculations become *too* complex, the problems that we described in the previous section would start to resurface.

Specifically, if Transpower was to undertake a larger number of LRMC calculations, e.g., for narrower geographic areas, or even individual assets, and updated those calculations regularly over time, then this could send more efficient price signals. However, it could also greatly increase administrative costs (which would ultimately be recovered through higher network charges for consumers), and also make those signals more difficult for DGs to predict and understand.

In other words, if Transpower decided to specify an up-front price for, say, smaller DGs (or other providers of non-network solutions), one of the key practical challenges it would face is the trade-off between accuracy and simplicity. Specifically, one of the key design issues would be how to strike the right balance between providing a reasonably accurate signal of long-run costs, while ensuring

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<sup>86</sup> Oakley Greenwood, 'Local Generation Network Credit Rule Change Proposal', Submission to: Australian Energy Market Commission, Proposed by: City of Sydney, Total Environment Centre, Property Council of Australia, 14 July 2015, p.26.



that any calculation do not become unduly burdensome, thereby undermining the purpose of specifying an up-front price in the first place.

## 6.4 Role of planning and investment framework

In section 5.1.3.2 and Appendix A we noted that Transpower and EDBs alike are required to prepare long-term planning documents describing the long-term operation and development of their networks. If Transpower took on a broader role contracting with DGs and other providers of non-network solutions, it is conceivable that interest in these planning documents would increase – perhaps significantly so.

Indeed, it is possible that some DGs have never had cause to review Transpower’s planning documents. Hitherto, the vast majority DGs would have approached their EDB for an ACOT payment. In this context, from the DG’s perspective, the location of pending transmission constraints may be neither here nor there. As we explained in section 3.1, under the status quo, a DG’s ACOT payments is not dependent upon it alleviating a constraint – it hinges solely on its effect on RCPD.

*If the proposed reforms proceed, the readership of Transpower’s planning documents is likely to grow.*

If the proposed reforms are implemented, the location of network constraints and the timing of future spending becomes very relevant indeed. Unless a DG delivers network cost savings, it is unlikely to be paid by Transpower (or an EDB). Investors in distributed generation and other non-network solutions would consequently wish to have access to transparent and reliable information on these matters so that they could identify and evaluate future investment opportunities.

An important question for Transpower is therefore whether the information currently available in its planning documents would be sufficient for this purpose. Our expectation is that the existing information could well be adequate for opportunities that arise out of the major capex framework, since Transpower is required to give explicit consideration to non-network options in this context. However, a key question is whether there would be enough transparent information for prospective investors in *smaller* non-network projects, i.e., less than \$20m.

The information in network planning documents has been a subject of debate in Australia recently. There, transmission businesses and EDBs are required to prepare annual planning reports (‘APRs’) in which they are required to identify (amongst other things) the locations of forecast network constraints.<sup>87</sup> The Australian Energy Regulator (AER) recently undertook a review of some of the businesses’ APRs. That process highlighted a number of shortcomings in the information that businesses were providing, which has resulted in improvements.

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<sup>87</sup> When that process identifies an investment need exceeding either \$5m for an EDB or \$6m for a transmission business, the RIT-D and RIT-T processes kick-in and the business is explicitly required to consider the costs and benefits of all credible network and non-network solutions.



Even so, one of the messages that emerged from the recent workshops run by the AEMC on the LGNC rule change proposal<sup>88</sup> was that, even with those improvements, proponents of non-network solutions in Australia still sometimes struggle to find what they need in network planning documents. One question that was raised was whether businesses could produce ‘heat maps’ that might, say, highlight in red, orange and green, respectively, the locations of near-, medium- and long-term constraints. This is something that Transpower could also consider.

*If networks are seen to favour network solutions this may place strain on the existing investment frameworks.*

Finally, we observed in section 5.1.3.3 that, in Australia, the vast majority (if not all) investments by networks in non-network solutions have arisen after the application of the formal RIT-T and RIT-D processes, i.e., when the businesses have been *explicitly required* to consider such alternatives. We also noted that, in New Zealand, there is no equivalent process for EDBs, and the threshold for Transpower is much higher than for the RIT-T, i.e., NZ\$20m versus A\$6m.

In our opinion, if the proposed reforms are implemented and Transpower and/or EDBs are seen to systematically favour network solutions – a possibility that we discuss in section 5.1.3.4 – then this may place some strain on the existing investment frameworks. In particular, it is conceivable that providers of non-network solutions – and consumer groups – may lobby the Commission to introduce arrangements more comparable to the RIT-T and RIT-D.

## 6.5 Summary

If Transpower assumes the broader role of contracting with DGs as envisaged in the Consultation Paper, it would face higher administrative costs transacting with a larger number of parties who would otherwise have dealt directly with their EDB to obtain an ACOT payment. Initially, many of these would be existing DGs. The only practicable way for Transpower to contract with these parties would be to consider whether its network costs would increase if a payment was not made.

The consequence of this approach would be that some existing DGs would be ‘held up’, but there is unlikely to be anything that Transpower could do to avoid that outcome, in practice. Any potential costs in terms of harm to ongoing investor confidence would then depend upon whether existing DGs’ decisions had hinged upon ACOT payments. If they had not – e.g., because investments were made before the status quo was in place – then those costs may be trivial, or zero.

In deciding how to go about contracting with DGs – both existing or new – Transpower would also have to consider whether it would do so on a pure ‘case-by-case’ basis, or whether it might endeavour to set out some price and/or non-price terms in advance. Each approach offers advantages and disadvantages, and it may even be feasible for Transpower to implement elements of both. For example:

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<sup>88</sup> Axiom Director, Hayden Green, led this rule change review from December until the end of February and presented at workshops in January (a webinar) and in February (in Brisbane).





- a 'case-by-case' approach would be likely to produce relatively efficient outcomes if it applied to 'larger' DGs with countervailing bargaining power, e.g., those bigger than, say, 5MW (to use the threshold adopted by the ESC); whereas
- for smaller DGs, it may be worthwhile defining some up-front criteria that would determine when a DG was eligible for a payment – and the size of that payment – without having to enter into a bespoke contract.<sup>89</sup>

The biggest design challenge that Transpower would face in terms of the specifying an up-front price under the latter approach would be the inevitable trade-off between accuracy and simplicity. Specifically, it would need to strike the right balance between providing a reasonably accurate signal of long-run costs, while ensuring that any calculations do not become unduly burdensome, thereby undermining the purpose of specifying up-front terms in the first place.

Finally, the proposed reforms may test the existing planning and investment frameworks for transmission. In particular, proponents of distributed generation projects may take a greater interest in the location of future network constraints – something that has not been vital to the receipt of ACOT payments in the past. An important question for Transpower is therefore whether the information currently available in its planning documents would be sufficient for this purpose.

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<sup>89</sup> We have assumed here that Transpower would not seek to exercise its substantial market power when dealing with smaller DGs which, for the reasons set out above, it could if it was so inclined. Instead, we have tried to set out an approach that, if implemented, might obviate the need for explicit regulatory pricing principles.



## Appendix A Comparison of regulatory regimes

This appendix provides an overview of the regulatory arrangements applied to electricity transmission and distribution businesses in New Zealand and Australia, and the various ways in which those regimes seek to incentivise efficient investment in and use of non-network solutions, such as distributed generation. There are some key differences to the New Zealand arrangements which, as we explained in section 5.1.3.4, may be relevant to the reform proposed in the Consultation Paper.

### A.1 New Zealand

In New Zealand, Transpower is subject to an Individual Price-Quality Path ('IPP') that is designed and administered by the Commerce Commission ('Commission'). The Consultation Paper suggests that this regulatory framework provides Transpower with beneficial incentives to make efficient trade-offs between capital and operating expenditure.<sup>90</sup> It also states that Transpower will have incentives to consider and procure 'transmission substitutes' where it is efficient to do so.

Under its IPP, Transpower's operating expenditure ('opex') and 'base' capital expenditure ('base capex') allowances are both subject to *ex-ante* approval by the Commission, prior to each regulatory period. The Consultation Paper notes that, under this framework:<sup>91</sup>

- Transpower is permitted to utilise non-network solutions such as distributed generation and other forms of demand response as alternatives to network expenditure, provided it can still meet the defined service standard;
- in evaluating Transpower's base capex, the Commission may review the internal processes applied and, in theory, it could challenge the need for a proposed network solution and question whether there are non-network options; and
- Transpower is subject to symmetric incentives that allow it to keep 33 cents of each dollar of savings in 'base' capex (i.e., projects less than \$20m) and opex in the control period – and contribute 33c of each dollar of 'over-spend'.

There are even more explicit requirements to consider non-network solutions when it comes to projects with expected capital expenditure of \$20m or more ('major capex'). These projects must be consulted on, assessed and approved on a project-by-project basis by the Commission by reference to Transpower's Capital Expenditure Input Methodology ('Capex IM').<sup>92</sup>

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<sup>90</sup> Consultation Paper §C.1.

<sup>91</sup> Consultation Paper §C.4.

<sup>92</sup> Latest version available [here](#).



Under the major capex framework, Transpower is required to explicitly consider transmission alternatives when assessing major capex projects.<sup>93</sup> Specifically, when Transpower notifies the Commission of its intention to undertake a major project, they must both agree on an approach to ensure appropriate consideration of non-transmission solutions and a consultation programme.

Transpower also operates a demand response programme, which covers both demand that can be directly managed, and reductions in net demand via use of controllable distributed generation. Transpower has been granted an opex allowance of \$8m over 2015-20 to fund the programme.<sup>94</sup> This allowance is not direct funding to defer any particular transmission investments. Rather, it is intended to develop and grow demand response capability more generally. It might therefore be characterised as a demand response ‘innovation allowance’.

Finally, Transpower is also required to publish an integrated transmission plan, the purpose of which is to explain its view of the long-term operation and development of the grid. Specifically, it must explain Transpower’s anticipated plans for the national grid and for associated expenditure over the next 10 years. This provides more transparency on Transpower’s planning activities and decision-making, and may assist non-network providers to put forward options – including distributed generation – as credible alternatives to network investment.

The arrangements applicable to EDBs are somewhat different. Sixteen EDBs are subject to a default price-quality path (DPP). The remaining businesses (many of which are consumer owned and therefore ‘exempt’ from the DPP) are subject only to information disclosure regulation (and Orion is subject to a ‘customised’ price-quality path (‘CPP’) as a result of the Christchurch earthquakes). Some of the key aspects of the DPP include the following:

- the ‘incremental rolling incentive scheme’ (‘IRIS’) that applies to both opex and capex under the DPP provides a mechanism by which suppliers can retain the benefits of efficiency gains beyond the end of a regulatory period, which provides some incentive to EDBs to explore non-network options as a way of potentially outperforming benchmarks; and
- at the completion of the Commission’s current review of input methodologies it is likely that the DPP will switch from a weighted average price cap to a revenue cap, which may enhance incentives to pursue any cost reductions that can be obtained through the adoption of non-network options (under a price cap, mechanisms that reduce volume can reduce overall revenues).

Like Transpower, each EDB is also required to prepare a long-term planning document. Specifically, each EDB is required to publish a detailed ten-year asset management plan (AMP) that provides information on how it intends to manage its

<sup>93</sup> Note that where use of a transmission alternative avoids a transmission investment that would otherwise be major capex, the transmission alternative is called a ‘non-transmission solution’.

<sup>94</sup> Commerce Commission, *Setting Transpower’s individual price-quality path for 2015 – 2020*, [2014] NZCC 23, §5.183.



assets to meet consumer demands. This aids transparency and again, in principle, it might make it easier for prospective providers of non-network solutions – such as DGs – to offer alternatives to planned network investments.

Perhaps the most noticeable difference between the DPP and the arrangements applied to Transpower is the comparative regulatory scrutiny of capital expenditure (capex). Although the Commission certainly looks at EDBs' capex forecasts (and their historical spending) when determining the DPP, there is no explicit regulatory approval of capex above a certain threshold like there is for Transpower's 'major capex' projects. There is also no requirement for EDBs to undertake a cost benefit analysis of different options when investments are expected to exceed a certain threshold (which must be done in Australia – see below).

## A.2 Australia

In Australia, the role of non-network approaches – such as demand-side management and distributed generation – formed a key aspect of several of the recommendations set out in the Australian Energy Market Commission's (AEMC's) Power of Choice review.<sup>95</sup> The Australian National Electricity Rules (NERs) now contain a number of mechanisms to incentivise efficient use of non-network solutions. These were set out in some detail in the AEMC's December 2015 Consultation Paper on the 'Local Generation Network Credits' rule change proposal, discussed in section 6.<sup>96</sup> They include:<sup>97</sup>

- **Cost-reflective distribution network tariffs:**<sup>98</sup> This rule change requires EDBs to develop prices that better reflect the costs of providing services to individual consumers so that they can make more informed decisions about their electricity use. Cost-reflective network tariffs can incentivise investment in forms of distributed generation that result in increased on-site consumption and/or export during peak times.
- **Network support payments:**<sup>99</sup> Providers of non-network solutions – including DGs with can negotiate with an EDB or a transmission business to receive network support payments. These payments can be expected to reflect the economic benefits the DG is providing to the business by delaying or avoiding

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<sup>95</sup> Australian Energy Market Commission, *Power of choice review – giving consumers options in the way they use electricity, Final Report*, 30 November 2012, Sydney.

<sup>96</sup> AEMC, *Local Generation Network Credits, Consultation Paper*, 10 December 2015, Sydney, pp.6-8.

<sup>97</sup> Note that several, but not all, of these mechanisms were introduced following recommendations in the Power of Choice review. For example, the network support payment, RIT-D and RIT-T and distribution network planning and expansion arrangements were not Power of Choice recommendations.

<sup>98</sup> Australian Energy Market Commission, *Distribution Network Pricing Arrangements, Rule Determination*, 27 November 2014, Sydney.

<sup>99</sup> See: NER clause 5.4AA.



investment in the network. The way in which businesses recover the costs of network support can differ between transmission businesses and EDBs.<sup>100</sup>

- **Avoided Transmission Use of System (TUoS) charges:**<sup>101</sup> EDBs are required to make payments to embedded generators with a capacity of more than 5MW if the presence of those generators reduces the energy supplied to the distribution network from the transmission network. The avoided TUoS payment reflects transmission charges the EDB saves.
- **The Regulatory Investment Test for Distribution (RIT-D) and Transmission (RIT-T):**<sup>102</sup> The RIT-D and RIT-T require EDBs and transmission businesses, respectively, to consider the costs and benefits of all credible network and non-network solutions where an investment need is projected to cost \$5 million or more (in the case of EDBs) or \$6m or more (in the case of transmission businesses). In some circumstances, the benefits will be maximised, or the costs minimised, by procuring embedded generation capacity.
- **The distribution network planning and expansion framework:**<sup>103</sup> This rule change (which also introduced the RIT-D) introduced obligations on EDBs to annually plan and report on assets and activities that are expected to have a material impact on the network. The rule also includes a number of demand-side engagement obligations on EDBs. This provides transparency on EDBs' planning activities and decision-making, and better enables non-network providers to put forward options – including distributed generation – as credible alternatives to network investment.
- **The Capital Expenditure Sharing Scheme (CESS) and the Efficiency Benefit Sharing Scheme (EBSS):**<sup>104</sup> These schemes provide EDBs and transmission businesses with incentives to invest in and operate their networks efficiently by allowing them to retain a portion of any cost savings, and to share the remaining portion with customers. This incentivises an EDB or transmission business to substitute a non-network solution for a previously anticipated investment in the network, if the former is more efficient.

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<sup>100</sup> When a network support payment is being made by a transmission business to a registered generator (i.e., a transmission-connected and embedded generator larger than 5MW) providing network support services as an alternative to network augmentation, it is permitted to pass-through 100% of the costs – even if it has spent more than it forecast. In all other circumstances, (e.g., when a transmission business is procuring network support services from generators smaller than 5MW), the costs of procuring that network support would still potentially be recoverable under the business' revenue cap (subject to the usual efficiency tests), but there would be no automatic recovery (pass-through) of any over-spend. There is no equivalent pass-through provision for EDBs procuring network support – they must *always* recover the costs through their revenue caps. DNSPs have asked the AEMC to introduce an equivalent pass-through for them in the past, but this proposal has been rejected.

<sup>101</sup> NER clause 5.5(h).

<sup>102</sup> See: NER clauses 5.16 and 5.15, respectively.

<sup>103</sup> Australian Energy Market Commission, *Distribution Network Planning and Expansion Framework, Rule Determination*, 11 October 2012, Sydney.

<sup>104</sup> See: NER clauses 6.5.8A and 6.5.8, respectively.



- The **demand management incentive scheme (DMIS)**:<sup>105</sup> The Australian Energy Regulator (AER) is required to publish an incentive scheme for network businesses to implement non-network investments where it is efficient to do so.
- The **demand management innovation allowance (DMIA)**:<sup>106</sup> The DMIA provides DNSPs with funding to undertake research and development in demand management projects. The allowance is used to fund innovative projects that have the potential to deliver ongoing reductions in total demand or peak demand, which could include embedded generation initiatives.
- The **small generation aggregator framework**:<sup>107</sup> This rule change sought to reduce the barriers to small generators participating in the market by enabling them to aggregate and sell their output through a third party (a Market Small Generator Aggregator). This makes it easier for those parties to offer non-network solutions, and for EDBs to procure those options when it is efficient to do so.

The AEMC has also sought to streamline the process by which DGs connect to the grid. The 'Connecting Embedded Generators' rule seeks to achieve this through a more transparent connection process, with defined time-frames and requirements on the part of the EDBs to disclose relevant information.<sup>108</sup> In addition, the 'Connecting Embedded Generators Under Chapter 5A' rule provides proponents of smaller scale embedded generation with a choice of two frameworks (the DG connection process in Chapter 5 of the NER or the connection process in Chapter 5A of the NER) when negotiating connection to a distribution network.<sup>109</sup>

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<sup>105</sup> See: NER clause 6.6.3 as set out in: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015.

<sup>106</sup> See: NER clause 6.6.3A as set out in: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015.

<sup>107</sup> Australian Energy Market Commission, *National Electricity Amendment (Small Generator Aggregator Framework) Rule 2012, Rule Determination*, 29 November 2012, Sydney

<sup>108</sup> Australian Energy Market Commission, *Connecting Embedded Generators, Rule Determination*, 17 April 2014, Sydney.

<sup>109</sup> Australian Energy Market Commission, *Connecting Embedded Generators Under Chapter 5A, Rule Determination*, 13 November 2014, Sydney