Assessment of the Electricity Authority's proposal to remove the distributed generation pricing principles

Response to the Electricity Authority's consultation paper

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Disclaimer

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1. Introduction and key findings

This report has been prepared by HoustonKemp at the request of Trustpower Limited (Trustpower) for public submission to the Electricity Authority (the EA). It responds to the EA's consultation paper on its review of the distributed generation pricing principles (DGPPs).[1]

The DGPPs are a set of principles set out in the *Electricity Industry Participation Code 2010* (the Code) that apply to determine the connection charges payable by owners of distributed generation in circumstances where they are unable to reach a negotiated agreement with a distribution business. The principles provide that connection charges must not exceed the incremental cost of providing connection services to a distributed generator, less the transmission and distribution costs that would be avoided as a result of connecting the generator. In practice, distribution businesses have applied these principles by making avoided cost of transmission (ACOT) payments to distributed generators based on the transmission charges the distributors avoid from having distributed generation operating in their network.

As part of its ongoing review of the transmission pricing methodology (TPM), in November 2013 the EA released a working paper ('the ACOT working paper') assessing the extent to which ACOT payments to distributed generators influence transmission and distribution investment, and whether ACOT payments provide other benefits.[2] The ACOT working paper concluded that ACOT payments, at least in their current form, do not promote efficient outcomes and, consequently, are inconsistent with the EA's statutory objective.

Following this, on 17 May 2016, the EA published a consultation paper on its review of the DGPPs. In this paper, the EA has proposed to remove the DGPPs from the Code. If this proposal is implemented, it would mean that incremental cost would no longer be the upper limit for charges paid by owners of distributed generation for connection services. Further, owners of distributed generation would be required to enter into commercial arrangements with Transpower and the distribution businesses to receive payments for any network benefits they provide, without having the current 'backstop' of the DGPPs to support those negotiations.

This report has been prepared jointly by Greg Houston, Ann Whitfield, Daniel Young and Ehson Shirazi.[3] We have been asked by Trustpower to assess the EA's proposal to remove the DGGPs and its supporting analysis, and to examine the implications of removing the DGPPs for efficient investment in distributed generation in New Zealand. In preparing this report the authors have read, and complied with, the Code of Conduct for Expert Witnesses as set out in Schedule 4 to the High Court Rules.

1.1 Key findings

The key findings of our review are as follows:

- The focus of the EA's analysis in both its earlier ACOT working paper and its current consultation paper is on payments to distributed generators for avoided transmission costs (ie, ACOT payments). However the current DGPPs require payments to distributed generators to reflect the benefits the generators provide in relation to both transmission and distribution networks.
- The EA appears to take the fact that payments to distributed generators to reflect the avoided costs of distribution (ie, ACOD payments) are currently the exception, as evidence that distributed generators provide very little benefit to distribution networks.

[1] Electricity Authority, *Review of distributed generation pricing principles - Consultation Paper*, 17 May 2016.

[2] Electricity Authority, *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation*, 19 November 2013.

[3] Greg, Ann, Daniel and Ehson are, respectively, Director, Director, Senior Economist and Economist at HoustonKemp. Details of our experience and qualifications are available on our website, www.houstonkemp.com.

  - At face value this does not appear to be a credible proposition. Evidence from other jurisdictions highlights that the benefits of distributed generation can be expected to accrue to distribution networks, as well as transmission networks. This is not something that has been explicitly investigated by the EA in either of its two papers to date.
  - A more compelling conclusion is that the absence of ACOD payments reflects the imbalance in the negotiating positions between distributed generators and network businesses. It is this imbalance that expressly motivated the introduction of the DGPPs.
- By focusing on ACOT payments only, the EA does not address the arrangements that cause ACOD payments to be significantly lower than the levels suggested by economic theory and international evidence. If current ACOD payments do not reflect the actual avoided costs of distribution, then the EA's proposal will not internalise the full value of the network benefits provided by distributed generation, and will not lead to efficient investment in distributed generation.
- The EA's conclusion that Transpower will have sufficient incentives to enter into commercial contracts with distributed generators where that is an efficient alternative to network investment is not supported by our assessment of the current institutional and regulatory framework. There are clear reasons to expect that Transpower will not always have sufficient incentive under the current framework to enter into agreements with distributed generators where it would be efficient to do so:
  - Under the current regulatory framework, Transpower's actual cost of capital may differ from the regulatory WACC determined by the Commerce Commission. This will lead to Transpower either over- or under- investing in non-network solutions, which are treated as operating expenditure under the regulatory framework, in preference to network solutions on which it will earn a regulated return;
  - The costs that Transpower faces in adopting network solutions are likely to be artificially lowered compared to the cost of non-network solutions, due to difference between Transpower's regulated cost of capital and a distributed generator's commercial cost of capital. This difference in costs can bias Transpower into selecting network solutions above non-network solutions, even where the resource cost to society is higher.
- In other jurisdictions, notably Australia, the incentives under the regulatory framework for network businesses to contract with non-network proponents where that represents an efficient solution are augmented by explicit obligations on the network business to provide information to the market on where those opportunities may exist, and to demonstrate that the expenditure it is proposing is the most efficient option, with explicit consideration of non-network alternatives. The regulatory arrangements in New Zealand do not provide similar complementary requirements to the same extent.
- The EA's proposal to remove the DGPPs would result in distributed generators again needing to negotiate commercial terms with both Transpower and the distribution business, without the 'backstop' that the DGPPs currently provide for those negotiations to counter-balance the information asymmetry that is otherwise recognised to exist in these negotiations.
- The removal of the DGPPs in this context represents a 'backwards step' in the provision of arrangements to facilitate efficient investment in distributed generation. The EA has failed to adequately investigate the rationale behind the introduction of the DGPPs, and as a consequence has not adequately considered the implications of the removal of the DGPPs on the efficient level of distributed generation investment.
- The EA's proposal to remove the incremental cost cap that is currently reflected in the DGPPs is inconsistent with the rationale that underpinned the introduction of the current cap, which was to ensure a level playing field between the network charges paid by transmission- and distribution- connected generation, so as not to adversely bias generation investment decisions.
  - The EA has not considered whether its proposed changes to the TPM and the likely changes to distribution pricing following changes to the distribution pricing methodology and the removal of the DGPPs will be likely to result in a level playing field, or will provide further disincentive for investment in efficient distributed generation;
  - It follows that the EA has not considered all of the implications of its proposal, and moreover, will not be in a position to properly do so until the TPM arrangements are specified in greater detail and consultation on the distribution pricing methodology has been completed. This suggests that the most appropriate course of action would be for the EA to cease its current consultation on proposed changes to the DGPPs until the proposals for changes to the TPM are further developed - and

Transpower has developed its methodology for implementing those proposals - and the EA has completed its consultation on the distribution pricing proposals.

- The EA's cost benefit analysis of the ACOT issue is not fit for purpose and does not establish that there will be a significant net benefit from the EA's proposal to remove the DGPPs.
  - The benefits estimated by the EA are exceedingly small, and, indeed, appear likely to be outweighed by the costs of EA staff in completing the current consultation;
  - The majority of the benefit categories have been 'estimated' and are not based on any empirical or principled finding;
  - The EA has assumed that there will be no costs associated with the proposed removal of the DGPPs, when in reality there can be expected to be costs in terms of both a reduction in efficient investment in distributed generation and resource costs associated with additional negotiations and disputes in order to determine appropriate connection charges, in the absence of the DGPPs.
- The EA's proposal is inconsistent with best practice principles for regulatory change since it will increase regulatory risk, and so the cost of capital, in the electricity market.
- Moreover, the EA has failed to consider alternative options for implementing its proposals. In particular, the extent of regulatory risk would be reduced where changes to regulatory settings are only made prospectively, for new investments, and are not imposed on existing investments, where they would represent a wealth transfer only.
  - Relevantly, such an approach would still promote the majority of benefits identified by the EA (77 per cent), as these benefits are associated with the impact of the EA's proposal on new investments only.

1.2 Structure of this report

The remainder of this report is structured as follows:

- section two provides an overview of the current network arrangements for distributed generation and the EA's proposal, as background to our assessment;
- section three identifies that the EA's analysis and discussion to date and its proposal to remove the DGPPs does not adequately recognise and support payments for avoided costs of distribution (ACOD);
- section four demonstrates why the EA's proposal to address the 'ACOT issue' is inconsistent with the efficient promotion of distributed generation, given the current regulatory and institutional arrangements for ACOD and ACOT payments, and contrasts these arrangements in New Zealand with the equivalent arrangements in Australia;
- section five discussed the 'connection services issue' and highlights that the EA's proposal is inconsistent with the rationale supporting the current incremental cost cap, and fails to consider the interaction with the EA's proposed changes to the TPM;
- section six explains why the EA's cost benefit analysis of the ACOT issue is not fit for purpose and does not establish that there will be a significant net benefit from the EA's proposal to remove the DGPPs; and
- section seven highlights that the EA's proposal is inconsistent with best practice principles for regulatory change since it will increase regulatory risk, and so the cost of capital, in the electricity market.

2. Overview of the EA's proposal

This section summarises the arrangements that currently apply to network connections for distributed generation in New Zealand, and the EA's proposal to remove the DGPPs currently in the Code. This provides relevant background for the analysis of these proposals in the following sections.

2.1 Network arrangements for distributed generation

Distributed generation is generation which is connected directly to an electricity distribution network. In New Zealand, there is around 950 MW of distributed generation.[4] Most of this capacity is provided by larger-scale facilities – the EA has noted that almost 600 MW is accounted for by power stations of 10 MW or more, while the ten largest distributed generators provide a combined total of 443 MW of capacity.[5] The generation mix is primarily comprised of hydro and wind facilities, with smaller amounts of geothermal, liquid fuel, natural gas facilities, biofuel, solar and other facilities.[6]

As well as being paid for the electricity they produce in the wholesale market, larger distributed generators are also remunerated for the services they provide to network businesses.

Under the Code, owners of distributed generation and distribution businesses may negotiate connection contracts for the services that each will provide, and the prices that will apply. If the parties fail to reach an agreement, or decide not to negotiate a connection contract, then a regulated set of terms will apply. The regulated terms require that prices are determined in accordance with the DGPPs in Schedule 6.4 of the Code. Amongst other things, these principles provide that:[7]

> connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation. To avoid doubt, incremental cost is net of transmission and distribution costs that an efficient distributor would be able to avoid as a result of the connection of the distributed generation

Where the resulting amount is negative, the distributed generator is deemed to be providing a network support service to the distributor and may invoice the distributor for this service. Costs that cannot be calculated, eg, avoidable costs, must be estimated. The estimate must be made with reference to reasonable estimates of how the distributor's capital decisions would differ, in the future, with and without the generation.

The DGPPs apply alongside the more general 'distribution pricing principles' developed by the EA's predecessor, the Electricity Commission, in October 2010. The distribution pricing principles are designed to guide distribution businesses in determining prices for all connections to a distribution network, including distributed generation. The principles state, amongst other things, that:[8]

> (a) Prices are to signal the economic costs of service provision by:
>
> (i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation
>
> [..]

[4] EA, *Review of distributed generation pricing principles – Consultation paper*, 17 May 2016, p.6.

[5] EA, *Review of distributed generation pricing principles – Consultation paper*, 17 May 2016, p.7.

[6] EA, *Review of distributed generation pricing principles – Consultation paper*, 17 May 2016, p.7.

[7] *Electricity Industry Participation Code 2010*, Schedule 6.2, Clause 2(a).

[8] EA, *Decision-making and economic framework for distribution pricing*, 5 March 2013, Appendix A, p.11.

(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:

[..]

(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (eg, distributed generation or demand response) and technology innovation.

Adoption of the distribution pricing principles is voluntary. However, the Commerce Commission information disclosure regime requires all distributors to disclose the extent to which their pricing methodologies are consistent with the distribution pricing principles. The EA also undertakes periodic reviews to evaluate how closely distributors' pricing methodologies align with the pricing principles.

2.2 The EA's proposal to remove the DGPPs

The EA has identified two issues with the DGPPs in its consultation paper. In the EA's view:

1. by making incremental cost, net of network benefits, an upper limit for charges paid by distributed generators for distribution services, the DGPPs mean that distributed generators do not contribute to the common costs of the distribution network (the '**connection services issue**'); and
2. by requiring distributors to pay to distributed generators the distribution and transmission cost savings resulting from their connection – and normal practice is for distribution businesses to pass through savings in transmission charges to distributed generators – the DGPPs typically do not reflect the actual transmission costs avoided (the '**ACOT issue**').

In response to these observations, the EA is proposing to remove the DGPPs from the Code. If this occurs, pricing for distributed generation will continue to be subject to the (voluntary) distribution pricing principles, as described above.

The EA contends that removal of the DGPPs will address the connection services issue since it will allow distribution businesses to adopt service-based and cost-reflective charges across all users of the distribution network, including owners of distributed generation. Under the EA's proposal, incremental cost would no longer be the upper limit for charges to be paid by owners of distributed generation for connection services. Distribution businesses would be able to set prices that signal the economic costs of providing distribution services, and hence could require owners of distributed generation to pay a share of common network costs.

In addition, the EA has argued that removal of the DGPPs will address the ACOT issue because it would leave Transpower solely responsible for obtaining and paying for transmission-substitute services that distributed generation provides. Under the proposal, distributors would not have to consider the effect on transmission costs when setting connection charges for distributed generation. Instead, owners of distributed generation would need to enter into commercial arrangements with Transpower to receive payments for any transmission network benefits they provide. This is expected to promote efficiency since, in the EA's view, Transpower is incentivised under the regulatory arrangements to enter into agreements with owners of distributed generation whose operation could efficiently reduce or defer transmission network costs, and is best able to assess the value of those services.

3. The EA's analysis fails to consider and address efficient ACOD payments

As a matter of principle, distributed generators should be remunerated for both transmission and distribution costs that are avoided as a result of their generation. However, the current application of the DGPPs has resulted in very few ACOD payments being made by distribution businesses to distributed generators.

The issue of facilitating efficient ACOD payments is not one that has been discussed by the EA in its consultation to date, which has focused solely on ACOT payments. In this section, we explain that the EA's proposal to remove the DGPPs does not address the reasons that cause current ACOD payments to be too low. Moreover, the EA has failed to recognise that the current low level of ACOD payments is likely indicative of the outcomes that can also be expected for ACOT payments, in the absence of the DGPPs.

3.1 Payments to distributed generation should reflect both ACOD and ACOT

Distributed generation can provide network benefits to both distribution and transmission networks. The most significant benefit is the potential for distributed generation to reduce network costs by deferring the need for network augmentation that might otherwise have been required in circumstances of growing peak demand. These benefits are realised in circumstances where distributed generation reduces load at peak periods, thereby allowing networks to delay (or avoid entirely) costly network upgrades that would otherwise be required but for the existence of the distributed generator. In addition, to the extent that distributed generators reduce the need for transmitting power across parts of the network, distributed generation creates the opportunity to consider resizing parts of the network at the time of replacement. Distributed generation can also provide benefits in relation to maintaining power quality.

In practice, the quantum of these benefits will depend on the specific circumstances of the network, and particularly the extent to which distributed generation can be directed to parts of the network where its benefits can be maximised. Efficient generation and network investment decisions therefore require effective signalling of these network benefits through payments to distributed generation. If distributed generators are not able to internalise these benefits, then investments that collectively generate positive wholesale market and network returns may not go ahead if the return in the wholesale market alone does not justify the project. If such efficient projects do not proceed, other projects that generate fewer net benefits may instead proceed, at a cost to society.

In order to encourage efficient investment in distributed generation, payments made to owners of distributed generators should reflect the network benefits they create for both transmission and distribution networks. Put another way, the payments should reflect both the avoided cost of transmission (ACOT) and the avoided cost of distribution (ACOD) attributable to the distributed generation. A failure to internalise all of the network benefits created by distributed generation creates a risk that investment in efficient distributed generation will either not proceed, or not occur on an efficient scale.

3.2 Current ACOD payments do not reflect potential distribution benefits

The current DGPPs recognise the importance of a 'whole-of-network' analysis by noting that connection charges for distributed generation should be net of both 'transmission and distribution costs that an efficient distributor would be able to avoid as a result of the connection of the distributed generation.'[9] However, in practice, most distribution businesses have applied the DGPPs by making ACOT payments to distributed generation, where the value of those payments is determined on the basis of the transmission charges that

[9] *Electricity Industry Participation Code 2010*, Schedule 6.2, Clause 2(a).

the distribution business avoids on account of that generator connecting to the network and operating at times of peak demand. We understand that very few ACOD payments are made to distributed generators by distribution businesses in their own right.

In other words, the application of the DGPPs in practice has resulted in payments to distributed generators that predominately reflect the benefits that are created for the transmission network,[10] and do not adequately reflect the benefits that are created for the distribution network.

The EA has interpreted the dearth of ACOD payments as being consistent with a view that distributed generators create little or no benefits for distribution networks. However there is neither a principled nor empirical basis for this view.

International evidence suggests that distributed generation creates considerable benefits for distribution businesses, through avoiding or delaying a significant investment in distribution assets. For example, a number of distribution businesses in Australia have adopted solutions in which they have either contracted with third party distributed generation providers or invested in distribution generation solutions themselves, in preference to implementing network options for addressing particular constraints or other issues in their network. We provide some examples below, with further details in Appendix A1:

- in 2012, the country Queensland distributor, Ergon Energy conducted a tender for third party embedded generation to defer the development of a new substation in the Southern Atherton Tablelands until November 2019. The employment of embedded generation allowed a network augmentation of A$17.3 million to be deferred four years;[11]
- in 2010, the South Australian distributor, SA Power Networks (SAPN), identified that projected network limitations at Bordertown substation could be addressed by employing embedded generation. The non-network solution would defer network upgrades that were estimated to cost more than A$10 million over several years. SAPN engaged Vibe Energy to provide third party support through an embedded generator at Bordertown;[12]
- in 2010, the NSW distributor, Ausgrid, invested in diesel generation in the Pennant Hills area (total cost of A$650,000), which allowed it to avoid a A$3.75 million investment that involved laying a new 11kV cable from Pennant Hills zone substation to the north of Cherrybrook;[13] and
- in 2012, AusNet Services in Victoria negotiated with a non-network provider, NovaPower, to install 10MW of gas-fired embedded generation at Traralgon, which became operational in 2013. The embedded generation allowed deferral of a new 220/33 MVA zone substation transformer for at least five years.[14]

An alternate, and more likely, explanation for why payments to distributed generators in New Zealand do not adequately reflect the benefits they create for distribution networks is that the prevailing institutional arrangements and regulatory framework do not support or incentivise appropriate levels of ACOD payments – we discuss these issues further in section 4.

In addition, the current practice of only making ACOT payments to distributed generators is likely to have incentivised investment in distributed generation that maximises transmission network benefits alone. Put another way, since there has been little history of distribution businesses making ACOD payments to owners of distributed generation, it is likely that investors have been reluctant to invest in distributed generation that

[10] We note that there is a separate issue as to whether ACOT payments that are based on avoided transmission *charges* are an adequate proxy for avoided transmission *costs*. However this is not the issue that is identified above, which is that current practice under the DGPPs, and the discussion by the EA in its papers to date, is predominantly focused on avoided transmission costs rather than also recognising avoided distribution costs. The DGPPs themselves are clear that it is both avoided transmission and distribution costs that are relevant.

[11] Ergon Energy, *Regulatory test – Final recommendation report – Proposed deferral of a new 66/33kV substation at Malanda*, 2014.

[12] SA Power Networks, *RFP 002/10 – Overload of Bordertown substation*, 2013.

[13] Ausgrid, *Demand management investigation report: North western Pennant Hills zone 11kV*, 2010.

[14] AusNet Services, 2014, *Energy insights: Demand management and smart network technologies*; AusNet Services, 2015, *AusNet Electricity Services Pty Ltd: Electricity distribution price review 2016-20;*

produces distribution network benefits – they are more likely to invest in distributed generation that provides transmission network benefits in order to maximise the ACOT payment they will receive.

3.3 The EA's proposal does not support efficient ACOD payments

The EA's proposal to remove the DGPPs does not address this shortcoming of the current arrangements. In its consultation paper, the EA focuses only on ACOT payments. That is, the EA has sought to show that ACOT payments are higher than avoided transmission costs, and that removal of the DGPPs will help to ensure that these payments better reflect the actual transmission costs that are avoided. However, by focusing on ACOT payments, the EA does not address the arrangements that cause ACOD payments to be significantly lower than the levels suggested by economic theory and international evidence. If current ACOD payments do not reflect the actual avoided costs of distribution, then the EA's proposal will not internalise the full value of the network benefits provided by distributed generation, and will not lead to efficient investment in distributed generation.

The EA's failure to address the arrangements for ACOD payments stems from its improper framing of the issue. In particular, the EA has attempted to reform the payments made to distributed generation by considering ACOT payments in isolation. However, this is inconsistent with the notion that distributed generation has the potential to create benefits for the whole network, ie, for the functions performed by both transmission and distribution assets. The stated purpose of the EA's consultation is to ensure that ACOD and ACOT payments overall are consistent with the network costs that are avoided as a result of the distributed generators connecting to the network. Focusing on one element of the problem (ie, ensuring that ACOT payments properly reflect actual avoided transmission costs) cannot be sufficient to produce efficient outcomes and is also inconsistent with the stated reform objective.

4. The current framework is insufficient to ensure efficient ACOD and ACOT payments, in the absence of the DGPPs

In this section we explain why the EA's proposal to remove the DGPPs is inconsistent with the promotion of efficient investment in distributed generation, given the current regulatory and institutional arrangements for ACOD and ACOT payments in New Zealand.

4.1 A regulated framework for the connection of distributed generation removes barriers to investment

The EA in its consultation to date has failed to give adequate consideration to the reasoning that led to the introduction of the DGPPs. As a consequence, it has failed to recognise and adequately mitigate in its proposals the adverse consequences of now removing the DGPPs.

Underpinning the development of the DGPPs was recognition by the New Zealand government that a set of standardised principles for connecting distributed generation was needed to address existing barriers to investment.[15] These barriers arose from asymmetry of information between distributed generators and network businesses on the benefits and costs that the generation will create for a network, which affected contract negotiations and subsequent connection terms and conditions.

In its 2006 discussion paper, the government noted as follows:[16]

> Distributors will generally have more information than generators do about the specifics of their network and how the potential operations of a generator may affect it. This asymmetry of information may affect contract negotiation and subsequent connection terms and conditions.

Prior to the introduction of the DGPPs, distributed generators had to approach their local distributor to make arrangements for the connection of their generation to the distribution network. Most distribution companies did not have standard terms and conditions for connecting distributed generation, which meant that every proposed distributed generation scheme required an individually negotiated connection contract. Connection requirements were not clearly defined and varied across distributors, and there was no consistent approach on how generators should pay for their network connection, nor consistent rules around how distributors should consider applications. This created uncertainty for the investor about the likely terms of connection, especially cost, and gave rise to disputes about the terms and conditions for connection.

For instance, in its 2003 discussion paper, the government noted that there were several distributed generation projects that had not proceeded because of difficulties in obtaining interconnection agreements with the local lines network company.[17] It went on to say as follows:[18]

> Given that investment in new distributed generation appears to be increasingly cost viable and economically attractive, it is important that other barriers to investment are addressed. As industry has been unable to develop clear rules for interconnection of distributed generation to lines networks and for retailing small quantities of electricity produced by non-retailers, government regulation to reduce investment uncertainty in these areas is proposed.

[15] Ministry of Economic Development, *Facilitating Distributed Generation: Second Discussion Paper*, September 2006, para 17.

[16] Ministry of Economic Development, *Facilitating Distributed Generation: Second Discussion Paper*, September 2006, para 15.

[17] Ministry of Economic Development, *Facilitating Distributed Generation: A Discussion Paper*, September 2003, p.7.

[18] Ministry of Economic Development, *Facilitating Distributed Generation: A Discussion Paper*, September 2003, p.9.

Similar concerns were voiced in its 2006 discussion paper, where the government noted that:[19]

- the requirements for connecting distributed generation were not clearly defined and varied across distributors, creating barriers to the connection of distributed generation;
- these barriers can be sufficiently large to warrant government intervention through regulating the terms and conditions for the connection of distributed generation; and
- the objective for the regulations would be to provide greater certainty and clarity by specifying a process for obtaining approval for connection of distributed generation, including interconnection requirements, principles for determining charges and fees, and a dispute resolution process.

The EA's proposal to remove the DGPPs will require distributed generators to negotiate privately in relation to the terms and conditions of connection with distribution networks, without the benefit of recourse to a regulated set of terms and conditions – in other words, the EA is proposing to revert back to the arrangements that were in place before the DGPPs were introduced. However, the EA has not demonstrated that the problems that were clearly identified by the government with this arrangement, being the considerations that the DGPPs were designed to address in the first place, are no longer applicable.

Indeed, the rationale underpinning the development of the DGPPs is as relevant today as it was when the principles were introduced. In particular, there is still asymmetry of information between distributed generators and network businesses, such that the network holds significantly more information than generators about the potential for distributed generation to affect their network. As a result, network businesses will have the 'upper hand' in any negotiation over connection terms and conditions. Similarly, the obligation to negotiate discrete agreements for each distributed generation project will create uncertainty for investors on the likely terms and conditions of connection, giving rise to disputes and the potential that efficient distributed generation projects will not proceed because of a failure to obtain a connection agreement. These factors suggest that the EA's proposal to remove the DGPPs will reintroduce the barriers to investment in distributed generation that the DGPPs were designed to remove.

4.2 Incentives to make ACOD and ACOT payments under the current regulatory arrangements are limited

The EA's assessment that its proposal to remove the DGPPs would still result in an efficient level of investment in distributed generation is predicated on its view that the regulatory incentives on transmission network service provider, Transpower, would ensure that it would:[20]

> … procure non-transmission solutions where it would be more efficient than investing in transmission assets.

In particular, the EA presupposes that Transpower would always implement the least cost option to alleviate a transmission constraint, whether that be:

- a transmission network investment option; or
- a distributed generation option; or
- a demand management option.

However, in the absence of the DGPPs, the incentives on Transpower to implement the least cost option depends crucially on the regulatory and institutional arrangements that apply to it. We explain below that the internal incentives on Transpower to maximise its profits may not necessarily align with the choice of the least cost option from a societal perspective. The consequence is that the EA is incorrect to conclude that removal of the DGPPs would result in an efficient level of investment in distributed generation.

[19] Ministry of Economic Development, *Facilitating Distributed Generation: Second Discussion Paper*, September 2006, para 17.

[20] EA, *Review of distributed generation pricing principles | Consultation Paper*, 17 May 2016, p. 13.

We have identified two distinct reasons why Transpower may not purchase an optimal level of distributed generation; these arise from:

- differences between the regulated weighted average cost of capital (WACC) and Transpower's actual cost of capital; and
- disparities between the internal cost to Transpower of pursuing network solutions and the costs Transpower faces in purchasing distributed generation, arising from differences in the WACC between a regulated and non-regulated business, which does not reflect differences in societal resource costs.

These reasons are discussed in turn below.

4.2.1 Transpower's regulated WACC

Transpower is regulated by the Commerce Commission (the Commission) under Part 4 of the Commerce Act 1986.

Network investments by Transpower represent new capital expenditure and so are added to Transpower's regulatory asset base (RAB). The regulatory framework allows Transpower to recover the costs of the network investment over the expected economic life of the assets by providing both:

- a return on capital at the regulated WACC, which compensates Transpower for the costs of equity and debt used to finance the investment; and
- a return of capital, which covers the cost of depreciating the network investment.

In contrast, if Transpower was to procure distributed generation services, the costs of these services would be recovered through the operating cost (or 'opex') element of its regulated revenue cap.

The regulated WACC is the expected benchmark rate of return that businesses require on their investments in order to compensate them for the risks they bear when investing in regulated activities. This is determined by the Commission as part of Transpower's Independent Price Path (IPP) decision. Transpower's current IPP allows it to earn 7.19 per cent on assets included in the RAB.[21]

Transpower's actual cost of capital may differ from the regulated WACC determined by the Commission, as the latter is intended to be a benchmark return, rather than an accurate estimate of Transpower's actual cost of capital. The implications of this potential difference are that:

- if the regulated WACC is greater than Transpower's cost of capital then the revenues generated from investing in network assets are greater than the cost of financing those assets; and
- if the regulated WACC is less than Transpower's cost of capital then the revenues generated from investing in network assets are less than the cost of financing those assets.

It follows that if the regulated WACC is above Transpower's actual cost of capital it will have an incentive to invest in network investments rather than purchase potentially more efficient distributed generation services. Alternatively, if the WACC is below Transpower's actual cost of capital then it will have an incentive to purchase distributed generation services rather than investing in more efficient network investments.

The EA's contention that the regulatory regime provides incentives for Transpower to make efficient choices as between non-transmission solutions and network augmentations is predicated on the assumption that the regulatory WACC matches Transpower's actual cost of capital. However, there are a number of reasons to suggest that this assumption may not necessary hold, including:

[21] Commerce Commission NZ, *Cost of capital determination for electricity distribution businesses' default price-quality paths and Transpower's individual price-quality path [2014] NZCC 28, 31 October 2014*, p. 2.

- the intrinsic difficultly of estimating elements of the WACC, especially the cost of equity, which has been explicitly acknowledged by the High Court of New Zealand:[22]

> Nevertheless, and as these appeals show, judgement and uncertainty is a feature of the estimation of all cost of capital parameter values.

- the Commission's practice of setting the WACC for Transpower at the 67th percentile of its WACC range, because:[23]

> The cost of capital [Input Methodologies] IMs currently specify a WACC above the mid-point estimate for price-quality paths because we expected the costs to consumers of under-estimating WACC to be greater than the costs to consumers of over-estimating WACC, given the uncertainty in estimating WACC. Our expert advisors at the time of the original IMs decision supported using a WACC above the mid-point.

- the Commission's practice of setting the WACC by reference to benchmark debt that may differ in terms of credit rating and term from Transpower's actual debt;[24] and
- our opinion that the Brennan-Lally capital asset pricing model (CAPM) used by the Commission underestimates the cost of equity for firms with low betas (such as Transpower), although we note that this view is not shared by the Commission.[25]

For these reasons, it is likely that the regulatory WACC may be higher or lower than Transpower's actual cost of capital. It follows that the Transpower cannot be presumed to purchase an efficient level of distributed generation but, rather, would harbour either:

- a bias against the purchase of distributed generation, ie, in favour of transmission assets, if the regulatory WACC is higher than its actual cost of capital; or
- a bias for the purchase of distributed generation, ie, against investing in efficient transmission assets, if the regulatory WACC is lower than its actual cost of capital.

4.2.2 Cost differences for Transpower between purchasing distributed generation and network augmentation

Setting to one side the question as to whether or not the regulatory WACC matches Transpower's actual cost of capital, there are other structural factors that strongly suggest that an insufficient level of distributed generation will be purchased by Transpower. Essentially, cost differences to purchase non-network services unrelated to differences in underlying resource costs means that Transpower will have an incentive to invest in network augmentations rather than purchase more efficient distributed generation services.

The principal reason that the cost of non-network services may result in an inefficient level of distributed generation being procured by Transpower is the likely difference between the distributed generator's private cost of capital and Transpower's regulatory WACC.

We illustrate this point below, drawing on an example of two equally efficient options for alleviating a network constraint. Suppose that a network constraint could be efficiently alleviated by means of an investment in either:

- a network augmentation at a capital cost of $10 million, which will alleviate the constraint for 10 years; or

[22] Wellington International Airport Ltd & ORS v Commerce Commission [2013] NZHC [11 December 2013], para. 1188.

[23] Commerce Commission NZ, *Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services | Reasons Paper*, 30 October 2014, p. 9.

[24] Commerce Commission NZ, *Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services | Reasons Paper*, 30 October 2014, p. 9.

[25] Commerce Commission NZ, *Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services | Reasons Paper*, 30 October 2014, p. 60.

- distributed generation that also addresses the constraint for 10 years, at a capital cost of $10 million and an annual operating cost of $2 million per annum, but which will also generate electricity sales of $2 million per annum.

Table 1 and Table 2 show a detailed breakdown of the costs to Transpower of these two options, under the assumptions that:

- the distributed generator's cost of capital equals the regulatory WACC;
- the distributed generator's costs are calculated on the basis of an indexed asset value; and
- there are no transaction costs in the purchase of non-network services.

Table 1 shows the capital-cost related increase in Transpower's revenues associated with a network investment under the following simplifying assumptions:

- initial capex of $10 million in an asset that has a 10 year economic life;
- no operating expenditure;
- a nominal WACC of 7 per cent;
- inflation of 2 per cent; and
- no company or personal income taxes.

Table 1: Illustration of regulated capital related revenues

Year	1	2	3	4	5	6	7	8	9	10
Opening RAB	10.00	9.18	8.32	7.43	6.49	5.52	4.50	3.45	2.34	1.20
Depreciation	-1.02	-1.04	-1.06	-1.08	-1.10	-1.13	-1.15	-1.17	-1.20	-1.22
Indexation	0.20	0.18	0.17	0.15	0.13	0.11	0.09	0.07	0.05	0.02
Closing RAB	9.18	8.32	7.43	6.49	5.52	4.50	3.45	2.34	1.20	0.00
Return on capital	0.70	0.64	0.58	0.52	0.45	0.39	0.32	0.24	0.16	0.08
Depreciation	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22
Indexation	-0.20	-0.18	-0.17	-0.15	-0.13	-0.11	-0.09	-0.07	-0.05	-0.02
Total revenues	**1.52**	**1.50**	**1.48**	**1.45**	**1.43**	**1.40**	**1.37**	**1.34**	**1.31**	**1.28**

In contrast, the cost associated with Transpower purchasing distributed generation will reflect the market price of these services. If we assume that such services are offered in a competitive market so that their price reflects the net costs of providing them, the price offered to Transpower will reflect the capital and operating costs of the distributed generator net of any revenues it expects to earn from selling generated electricity.

Table 2 shows the net cost of providing distributed generation services to Transpower under the following simplifying assumptions:

- initial capex of $10 million in an asset that has a 10 year economic life;
- operating expenditure $2 million per annum;
- $2 million in annual sales of electricity;
- a nominal WACC of 7 per cent;

- inflation of 2 per cent; and
- no company or personal income taxes.

Table 2: Illustration of net cost of distributed generation

Year	1	2	3	4	5	6	7	8	9	10
Opening asset value	10.00	9.18	8.32	7.43	6.49	5.52	4.50	3.45	2.34	1.20
Depreciation	-1.02	-1.04	-1.06	-1.08	-1.10	-1.13	-1.15	-1.17	-1.20	-1.22
Indexation	0.20	0.18	0.17	0.15	0.13	0.11	0.09	0.07	0.05	0.02
Closing asset value	9.18	8.32	7.43	6.49	5.52	4.50	3.45	2.34	1.20	0.00
Electricity sales	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Cost of capital	-0.70	-0.64	-0.58	-0.52	-0.45	-0.39	-0.32	-0.24	-0.16	-0.08
Depreciation costs	-1.02	-1.04	-1.06	-1.08	-1.10	-1.13	-1.15	-1.17	-1.20	-1.22
Indexation	0.20	0.18	0.17	0.15	0.13	0.11	0.09	0.07	0.05	0.02
Operating costs	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00
Net costs	**-1.52**	**-1.50**	**-1.48**	**-1.45**	**-1.43**	**-1.40**	**-1.37**	**-1.34**	**-1.31**	**-1.28**

In this scenario, Transpower is financially indifferent as between one option and another, since the costs to it of both the distributed generation and the network augmentation options are the same.

However, the scenario below shows the implications of relaxing the assumptions that underpin the above results and, in particular, the impact of differences between the distributed generator's cost of capital and the regulatory WACC applicable to network assets.

The cost of capital for a private distributed generator is unlikely to equal Transpower's regulated WACC. Rather, there are a number of factors that suggest that the regulated WACC will be lower than the return that a private business would require to invest in a distributed generator, including:

- Transpower owns the national transmission network which is a regulated monopoly while the distributed generation services are unregulated;
- the return on a distributed generation investment will partially depend on the revenues generated from the sale of electricity in the wholesale market, which are likely to be much riskier than Transpower's revenues; and
- a distributed generator is unlikely to achieve the same credit rating or debt gearing ratio as that assumed in the regulatory WACC.

We show the impact of a higher required return on capital for distributed generation in Table 3 below. This table adopts all the same values as those in Table 2 with the exception of a higher rate of return of 10 per cent.

Table 3: Illustration of net cost of distributed generation assuming a private rate of return of 10%

Year	1	2	3	4	5	6	7	8	9	10
Opening asset value	10.00	9.18	8.32	7.43	6.49	5.52	4.50	3.45	2.34	1.20
Depreciation	-1.02	-1.04	-1.06	-1.08	-1.10	-1.13	-1.15	-1.17	-1.20	-1.22
Indexation	0.20	0.18	0.17	0.15	0.13	0.11	0.09	0.07	0.05	0.02
Closing asset value	9.18	8.32	7.43	6.49	5.52	4.50	3.45	2.34	1.20	0.00
Electricity sales	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Cost of capital	-1.00	-0.92	-0.83	-0.74	-0.65	-0.55	-0.45	-0.34	-0.23	-0.12
Depreciation costs	-1.02	-1.04	-1.06	-1.08	-1.10	-1.13	-1.15	-1.17	-1.20	-1.22
Indexation	0.20	0.18	0.17	0.15	0.13	0.11	0.09	0.07	0.05	0.02
Operating costs	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00
Net costs	**-1.82**	**-1.77**	**-1.73**	**-1.68**	**-1.62**	**-1.57**	**-1.51**	**-1.45**	**-1.38**	**-1.31**

The higher cost of capital for a distributed generator would require Transpower to pay a higher price for distributed generation services, as compared with an equally efficient network solution. It follows that where the private rate of return for distributed generation is higher than the regulatory WACC, Transpower will purchase a sub-optimal level of distributed generation.

By way of reinforcement of this conclusion, we note that Australia's regulatory investment test for both transmission and distribution (the RIT-T and RIT-D) require a network business to apply a common commercial discount rate to all investment options (both network and non-network). This ensures that the choice of investment options is not biased on account of the differences between a commercial rate of return and the regulatory rate of return earned on network investments.

In our opinion, the above discussion highlights that Transpower is likely to have relatively low incentives to provide an efficient level of ACOT payments to distributed generators. Moreover, we note that the distribution businesses in New Zealand operate under a similar regulatory regime. The low level of ACOD payments currently made appears therefore to provide empirical confirmation of these low incentives. [26]

Concerns in relation to reliance on incentives under the regulatory regime alone to result in the efficient adoption of non-network alternatives have been recognised in other jurisdictions. For example, in Australia the regulator commented in a recent decision for one of the electricity distribution businesses that:[27]

> The current incentive frameworks and obligations in the [National Electricity Rules] are designed to encourage distributors to make efficient investment and expenditure decisions. However, the [National Electricity Rules] recognises that the planning and investment framework and the incentive regulation structure may not be sufficient by themselves to remove any bias towards network capital investment over non-network responses.

As a consequence, the National Electricity Rules (NER) in Australia include additional arrangements intended to ensure that network support payments to non-network providers are actively considered by the network businesses as part of its investment evaluation process (discussed further below).

[26] In the case of the distribution businesses, the Commission's policy of indexing the regulatory asset base for the distribution businesses provides a further reason why the costs to a distribution business of a network and non-network solution may differ, resulting in distribution businesses favouring network investment over payments to distributed generation.

[27] AER, *Endeavour Energy Final Decision 2015-19, Attachment 6 – Capital expenditure*, 30 April 2015, p.65.

The current DGPPs play a similar role in New Zealand, in terms of ensuring that there is active consideration of the potential benefit (or cost) that distributed generation provides to the network at the time of negotiating connection agreements. By proposing to remove the DGPPs, and rely only on the incentives in the regulatory framework to deliver efficient outcomes, the EA is taking a backwards-step compared to both the development of the current arrangements and the arrangements that have been adopted in comparable jurisdictions.

4.3 Institutional arrangements for ACOD and ACOT payments are weak

The DGPPs that the EA proposes to remove constitute an important component of the existing framework for promoting investment in distributed generation as an alternative to network investments. Other aspects of the institutional arrangements in New Zealand are not effective in promoting non-network alternatives to network investment.

4.3.1 Current arrangements for considering distributed generation are inadequate

In transmission, the capex input methodology (IM)[28] distinguishes between two types of capital expenditure, namely:

- ***base capex***, which covers capital expenditure incurred in relation to asset replacement or refurbishment, business support, and information system and technology assets, with an aggregate value less than the base capex threshold (NZ$20 million); and
- ***major capex***, which covers capital expenditure incurred to meet grid reliability standards or provide a net electricity market benefit, and is not base capex – this includes 'non-transmission' solutions, such as investment in electricity generation and demand-side response programs.

Base capex is subject to ex-ante approval. Transpower is required to submit a base capex proposal that details proposed base capex programmes and projects prior to the start of a regulatory period, and the Commission will determine a base capex allowance (together with various incentive adjustments) for each year of the regulatory period.

However, the capex IM does not explicitly require Transpower to consider distributed generation or any other non-network solutions as possible alternatives to undertaking that base capex when preparing its proposal. For example, Transpower is under no obligation to consider non-network options in determining whether to replace an existing transmission network asset, where the replacement does not materially improve the original service potential beyond that attributable to using modern equivalent assets, and the total value of the replacement capex is less than NZ$20 million.

In contrast, major capex is approved on a project-by-project basis at any time during a regulatory period. In short, Transpower will notify the Commission of its intention to plan a major capex project and, prior to submitting its proposal, consult with interested parties on its investment need and the potential investment options. Following this, Transpower will apply the 'investment test' to identify which of the possible options should be the proposed investment, and then submit its major capex proposal to the Commission for approval. As part of this process, Transpower is required to invite interested persons to provide views or information on possible non-transmission solutions, and to take those views and information into account when developing its list of potential investment options.

These provisions provide only very general requirements for Transpower to consider distributed generation solutions. In particular, the capex IM does not require Transpower to identify or set out information on the technical characteristics that non-transmission options would need to meet to address an investment need for stakeholders to consider (although it may do this of its own accord). In addition, there are no requirements that explicitly dictate the extent of consideration that Transpower should give to any non-transmission proposals that are received – for instance, the capex IM provides that Transpower should be

[28] Commerce Commission, *Consolidated Transpower Capital Expenditure Input Methodology Determination* as at 5 February 2015.

'pro-actively engaging with the parties' that have provided non-transmission proposals, without indicating what this engagement actually requires. The generality of these requirements gives rise to the potential for inconsistent consideration of non-transmission solutions as between different major capex proposals.

On the other hand, the capital expenditure planning and assessment obligations on distribution businesses are subject principally to information disclosure requirements. The current arrangements include a requirement for distribution businesses to provide information on non-network options that have been implemented, or that have been considered or proposed. However, given the light-handed nature of the regulatory framework, the ability to require robust assessment of such options is limited. There is no capacity for the Commerce Commission to require a distribution business to engage with stakeholders on potential non-network solutions, to investigate non-network solutions that have been proposed, or to implement a non-network solution in preference to a network alternative.

Finally, we note that the distribution pricing principles that would remain applicable to distributed generation do refer to prices 'where network economics warrant, and to the extent practicable, encouraging investment in transmission and distribution alternatives'. However these principles are voluntary, and do not have the same mandatory status as the current DGPPs.

By contrast, overseas regulators understand that networks may have limited incentives in seeking non-network alternatives, and so require explicit consideration of such options in all significant investment decision-making. In the following section, we consider the institutional arrangements in Australia that place explicit obligations on network businesses to assess non-network alternatives, including distributed generation, and which complement the incentive regime.

4.3.2 Australia has extensive arrangements for considering distributed generation

In Australia, the incentive-based regulatory framework established in the National Electricity Rules (NER) is designed to encourage networks to make efficient investment and expenditure decisions. However, there is recognition that this framework may not be sufficient by itself to remove any bias towards network capital investment over non-network options. As such, the NER include a number of mechanisms that explicitly incentivise network businesses to assess non-network alternatives. We describe the principal arrangements below.

The Regulatory Investment Tests for Transmission and Distribution

The NER require distributors to examine non-network alternatives when proposing major network investments, with such decisions being made by reference to either the regulatory investment test for distribution (RIT-D) or the regulatory investment test for transmission (RIT-T).[29] In general terms, the RIT-D and RIT-T are economic cost-benefit analyses that require network businesses to engage in an open process of assessing and ranking alternatives to major network investments, including transparent consideration of non-network alternatives.

The overarching purpose of these schemes is to identify the credible network or non-network option that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the market. Both schemes must be applied in all cases where the estimated capital cost of the most expensive credible option is over A$5 million.

Both the RIT-D and the RIT-T require network businesses to consider non-network options as part of this assessment framework, and establish an open and transparent process for engaging with stakeholders on credible non-network solutions. Specifically, network businesses are required to publish the technical characteristics that a non-network solution would be required to deliver to address an emerging investment need, such as the number of times a year that the non-network alternative would be expected to be called, the size and duration of the load reduction or additional supply required, the location, and so on.

[29] AER, *Regulatory Investment Test for Distribution*, 23 August 2013; AER, *Regulatory Investment test for Transmission,* June 2010.

Transmission businesses are required to publish this information for all investments subject to the RIT-T.[30] Distribution businesses are required to publish this information (in a 'non-network options report') for all investments subject to the RIT-D, and to provide it to non-network providers and (if relevant) persons registered on the distributor's demand side engagement register.[31] The exception is that if the distribution business determines 'on reasonable grounds' that there will not be a non-network option that is a potentially credible option, they are required to publish a notice setting out the reasons for reaching this view. A list of the information that is required to be included in a non-network options report is set out in Box 1 below.

Box 1: Information to be included in a non-network options report under the RIT-D

A non-network options report must include:

1. A description of the identified need;
2. The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);
3. If available, the relevant annual deferred augmentation charge associated with the identified need;
4. The technical characteristics of the identified need that a non-network option would be required to deliver, such as:
    i. the size of load reduction or additional supply;
    ii. location;
    iii. contribution to power system security or reliability;
    iv. contribution to power system fault levels; and
    v. the operating profile;
5. A summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options and non-network options;
6. For each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on:
    i. a technical definition or characteristics of the option;
    ii. the estimated construction timetable and commissioning date (where relevant); and
    iii. the total indicative cost (including capital and operating costs); and
7. Information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a non-network proposal for consideration by the RIT-D proponent.

Source: NER, clause 5.17.4(e).

Proponents of non-network options are then given at least 12 weeks to submit proposed solutions, which the network business is required to consider in its investment evaluation. In the initial consultation phase, the network is also required to consider indicative non-network options, even if there are no proponents for such options, in order to demonstrate whether a non-network solution is likely to be cost effective, and if so, potentially to elicit a proponent for that solution.[32]

[30] NER 5.16.4 (b)(3). This document is called the Project Specification Consultation Report.

[31] NER 5.17.4(b).

[32] Clause 5.15.2(d) of the NER states that the absence of a proponent does not exclude an option from being considered a credible option. However, for an option that is required to meet a reliability standard, the preferred option does need to have a proponent. (NER, clause 5.16.4(l)).

The Australian Energy Regulator (AER) has said of these arrangements:[33]

> The RIT-D requires distribution network businesses to consult with stakeholders on the need for new capex projects and consider all credible network and non-network options as part of their planning processes. Its aim is to create a level playing field for the assessment of non-network options, such as demand-side management, against network options.

The AER has also recently submitted a proposed change to the regulatory arrangements that would require network businesses to also apply the regulatory investment tests to all replacement expenditure, as well augmentation expenditure.[34]

> Under the proposal, network businesses would be required to signal early potential opportunities for new technologies or demand-side options which arise out of decisions to retire an asset. This is particularly important given that there are now potentially a range of alternatives to 'like for like' replacement of network assets, given the pace of technological change we are seeing in electricity markets.

The Capital Expenditure Criteria

Even where a network business is not formally required to undertake a RIT-T or RIT-D, a similar assessment of credible non-network options is required as part of the regulatory determination for network businesses.

Under the NER, the AER is required to determine the efficient and prudent capital expenditure that a network business will require over a forthcoming regulatory period in order to achieve particular objectives, including meeting or managing expected demand for network services, complying with all regulatory obligations, and maintaining the quality, reliability and security of the network. In undertaking this assessment, the NER explicitly requires the AER to consider the extent to which a network business has considered efficient and prudent non-network options.[35] This has led to the AER actively questioning network businesses on whether network investments can be delayed if alternative non-network solutions are pursued.

The Demand Management Incentive Scheme

The NER allows the AER to develop and publish a demand management incentive scheme (DMIS) to incentivise distribution businesses to undertake demand management projects as an alternative to building new network infrastructure.

The current version of the scheme consists of an ex-ante allowance (the demand management innovation allowance, or the DMIA) provided to distribution businesses at the commencement of each regulatory year to fund research and investigation into innovative demand management techniques, including connecting distributed generators to the network. In 2011, the AEMC made a change to the NER to specifically require the AER, in developing and implementing the DMIS, to consider improving the incentives for distribution businesses to consider ways of more efficiently connecting embedded generators. The AEMC justified this amendment by noting as follows:[36]

> DNSPs currently have weak incentives to minimise the connection costs of embedded generators due to their focus on ensuring connections meet the network security and reliability standards applicable to relevant DNSP. While maintaining these technical connection standards are important, if they are in excess of the necessary minimum requirements to maintain system security and reliability of supply, then the additional costs to meet those prescribed standards may discourage embedded generators from connecting to the distribution network

[33] AER, *Final Decision: Endeavour Energy Distribution Determination 2015–19 – Attachment 6: Capital Expenditure*, April 2015, p.65.

[34] http://www.aer.gov.au/news-release/energy-regulator-proposes-network-planning-reforms, 14 July 2016.

[35] NER, clause 6A.6.6 (e)(12); NER, clause 6.5.7(e)(10).

[36] AEMC, *Rule Determination – National Electricity Amendment (Inclusion of Embedded Generation Research into Demand Management Incentive Scheme) Rule 2011*, 22 December 2011, p.i.

On August 2015, the AEMC introduced rules providing for the development of a new DMIS. [37]

The amendment followed a rule change request from the COAG Energy Council and the Total Environment Centre to address concerns that the regulatory framework created a bias towards expenditure on network investment over non-network options, and provided limited incentives to consider new non-network options. Both proponents noted that there are greater uncertainties and risks associated with demand management options compared with traditional network investment and that the stable returns generally associated with capital expenditure meant the businesses were likely to favour capital investment as the means for addressing network limitations and demand growth. In this context, the proponents did not consider that the existing DMIS was providing sufficient incentive or certainty for distribution businesses to explore and develop efficient demand management options as an alternative to network investment.

The new rules separate the current scheme into two distinct parts – the DMIS and the DMIA – and provides greater clarity to the AER and stakeholders in respect of how a mechanism to encourage efficient demand management should be designed and applied. The AER is currently in the process of developing the new scheme. Once developed, the new scheme is expected to strengthen the incentives for DNSPs to invest in demand management options, including distributed generation.

The Demand Side Engagement Strategy

Each distribution business is required to develop and publish a *Demand Side Engagement Strategy* as part of the distribution annual planning review requirements set out in Chapter 5 of the NER.

This requires distribution businesses to:

- prepare and publish a ***demand side engagement document*** that sets out its process and procedures for engaging with non-network providers and assessing non-network options as alternatives to network investment;
- establish, maintain and publish a ***demand side engagement database*** of non-network proposals and/or case studies that demonstrate assessments it has undertaken in considering non-network proposals; and
- establish and maintain a ***demand side engagement register*** for parties wishing to be advised of relevant developments related to a distribution business' planning activities.

The Demand Side Engagement Strategy was developed in light of concerns raised by stakeholders that it was difficult for non-network providers to engage with distribution businesses at an appropriate stage of the planning process, and that there was limited transparency on how distribution businesses considered non-network proposals. The strategy is designed to address these issues by providing transparency and clarity around the processes adopted by distribution businesses to assess non-network options, promoting the engagement of non-network providers, and providing improved opportunities for non-network providers and distribution businesses to interact productively.

The Australian Energy Market Commission (AEMC) has said of these arrangements:[38]

> [The Demand Side Engagement Strategy] recognises the importance of proactive engagement by both DNSPs and non-network providers in the development of potential solutions to address system limitations.
>
> The Demand Side Engagement Strategy would be a key component of the national framework. It builds on current industry practice, and promotes a constructive working relationship between the distribution businesses and non-network providers. The strategy would work together with the

[37] The AEMC has amended the NER to address certain shortcomings in the current incentive scheme, and strengthen the incentives to distribution businesses to investigate demand management options. These amendments are due to commence on 1 December 2016. (see: AEMC, *Rule Determination – National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, 20 August 2015).

[38] AEMC, *Final Report – Review of National Framework for Electricity Distribution Network Planning and Expansion*, 23 September 2009, p.viii.

Distribution Annual Planning Report and RIT-D to address a perceived failure by DNSPs to assess non-network alternatives in a neutral manner.

Local generation network credits

The AEMC is currently considering a rule change request from the City of Sydney, Total Environment Centre and Property Council of Australia that would introduce a payment from distribution networks to embedded generators in the form of local generation network credits (LGNC) for benefits that embedded generators provide to the network.[39] In particular, the proposed rule change would require distribution businesses:

- to calculate the long term benefits that embedded generators provide in terms of deferring or downsizing network investment or reducing operating costs; and
- to pay all types of embedded generators a LGNC that reflects those estimated long term benefits (netting off any additional costs).

The proponents of the rule change argue that existing mechanisms for the consideration of non-network options are insufficient. Specifically, barriers exist for smaller scale embedded generation since:

- the cost of negotiating arrangements between the network and embedded generator will almost always outweigh the potential benefits on offer from a single small sale embedded generation; and
- network businesses generally require provision of firm capacity, which is difficult for individual small scale embedded generators to offer.

The proponents argue that this gap in the NER for small scale embedded generation leads to insufficient small scale embedded generation investment, too much network investment, and small scale embedded generation being utilised in inefficient ways (eg, overconsumption by embedded generators, under provision of network support). Ultimately, consumers will be worse off from higher costs in the short and long term.

The proposed rule change aims to address a perceived inefficiency in investment and use of aggregated small scale embedded generation by providing for the payment of an LGNC, or a negative network tariff that reflects the long term benefits that embedded generators provide to distribution businesses. The amount of credits paid would reflect the benefit from deferring or down-sizing network investment, and any reductions in operating and maintenance costs. The LGNC would also be net of any increases in capital or operating costs that might arise from the distributor needing to cater for bi-directional/localised energy flow from embedded generators.

4.3.3 Summary

Networks may have limited incentives in seeking non-network alternatives. As a result, regulators must ensure that the overall institutional and regulatory framework also provides sufficient obligations and transparency requirements to engender adequate and effective consideration of non-network options in all significant investment decision-making.

In Australia, there are arrangements that place specific obligations and incentives on network businesses to assess non-network alternatives, including distributed generation. There is also an ongoing drive to actively consider the adequacy of the current arrangements, as evident from a recent rule change to strengthen the incentives under the DMIS, and the AEMC's ongoing consideration of a rule change request to introduce local generation network credits. Both the AEMC and the AER have noted that the current arrangements are necessary to create a level playing field for the assessment of non-network options as alternatives to network solutions.

In New Zealand, the DGPPs are an important component of the existing framework for promoting investment in distributed generation. In the absence of the DGPPs, existing regulatory arrangements alone cannot be

[39] AEMC, *Consultation paper: National Electricity Amendment (Local Generation Network Credits) Rule 2015*, 10 December 2015.

expected to be effective at promoting non-network alternatives to network investment. In particular, the capex IM provides only very general requirements for Transpower to consider non-transmission options for major capex projects, while the light-handed regulatory regime applying to distribution businesses' capex decisions does not oblige distributors to consult on, or consider, non-network options. In addition, the distribution pricing principles that would remain applicable if the DGPPs are removed are only voluntary rather than mandatory requirements on distributors.

In the absence of an extensive and multifaceted framework for considering non-network options, removal of the DGPPs will only serve to undermine investment in distributed generation. Moreover, given that the EA has identified that the bulk of the benefits it estimates from removal of the DGPPs occur in the first two years,[40] prior to the full implementation of the changes in TPM, it is improbable that such an alternate framework could be introduced and functioning within this period.

4.4 Bargaining power for ACOD and ACOT payments is asymmetric

Under the EA's proposal to remove the DGPPs, owners of distributed generation will be required to negotiate with Transpower and distribution businesses on the value of any ACOT and ACOD payments, respectively. However, the bargaining power in these negotiations is asymmetric, putting the owners of distributed generation at a natural disadvantage, and undermining their capacity to negotiate fair and efficient terms.

The asymmetry in bargaining power arises from two main sources, namely:

- *Asymmetry of information* – as noted in section 4.1, a network business will always have more information than generators about the potential for distributed generation to affect their network. In addition, the obligation to negotiate discrete agreements for each distributed generation project will create further uncertainty for investors on the likely terms and conditions of connection. This information asymmetry will undermine negotiated outcomes by preventing distributed generators from negotiating on an equal footing with network businesses, potentially leading to inefficient outcomes. In the absence of full and frank disclosure of relevant information, network businesses will have the 'upper hand' in any negotiation over connection terms and conditions, including the appropriate value of ACOT and ACOD payments.
- *Asymmetry of options* – existing distributed generators, who have already made investments, will have little ability to negotiate effectively with Transpower or distribution businesses. These generators have little alternative but to reach a deal with the network – the sunk nature of their investments, and their relative inability to relocate, means that failure to reach an agreement may result in significant financial impacts. In contrast, network businesses may pursue different options, including dealing with existing distributed generation, dealing with new distributed generation, or even building network assets. This creates an imbalance of power that network businesses can leverage to set ACOT and ACOD payments below a level that reflects the true benefits that existing distributed generation creates for the network.

The DGPPs recognise this asymmetry by setting out minimum requirements for a connection agreement, which apply if the parties cannot themselves reach agreement. This provides a reason for Transpower and the distribution businesses 'to come to the table'.

If the DGPPs were removed, the imbalance of bargaining power between network businesses and owners of distributed generation would affect the likely outcome of any negotiations for connection agreements. In particular, network businesses will be better placed to negotiate connection terms and conditions that will advantage them, giving rise to a transfer of wealth from distributed generators to network businesses, and increasing the likelihood of inefficient outcomes.

[40] See discussion in section 6.2 of this report.

5. The 'connection services' issue

The previous two sections have discussed the 'ACOT issue', identified by the EA.

The EA has also identified what it has termed the 'connection services' issue. Under the EA's proposal, incremental cost would no longer be the upper limit for charges paid by owners of distributed generation for connection services. As such, owners of distributed generation could be required to pay a share of common network costs, as is presently the case for other network users. However, this outcome is inconsistent with the rationale which underpinned the introduction of the incremental cost cap, and does not take into account the impact of the EA's proposed changes to the TPM.

5.1 The EA's proposal is inconsistent with the rationale for the incremental cost cap in the DGGPs

The incremental cost cap for distributed generation was introduced to place distributed generators on an equal footing with generation connected to the transmission network, and thereby promote investment in distributed generation.

5.1.1 Rationale for the incremental cost cap

Under the current TPM, generators connected to the transmission network are not required to contribute to the common costs of the transmission or distribution network. These generators are only required to pay the incremental costs associated with connecting to the network – see Box 2 below

Box 2 – Current charging arrangements for transmission connected generators

The current TPM comprises three charges, namely:

1. the **connection charge**, which recovers the cost of assets connecting transmission customers to the transmission grid. Connection charges are paid by customers (both load and generation) who use the connection assets;
2. the **HVDC charge**, which recovers the cost of the high voltage direct current (HVDC) link between the North Island and the South Island. HVDC charges are paid by South Island generators on the basis of their share of historical anytime maximum injections (HAMI) in the South Island. This is being replaced over a four-year transition period by a charge based on South Island generators' mean injections (SIMI) averaged over a five-year period; and
3. the **interconnection charge**, which recovers the remainder of Transpower's revenue relating to the regulated parts of the grid. This charge is paid by distributors and direct consumers. The interconnection charge is a 'postage stamp' charge based on a customer's contribution to demand at peak times, ie, using a 'postage stamp' rate of NZ$110.35 per kW of regional coincident peak demand per annum.

Transmission connected generators in New Zealand are only required to pay the 'connection charge' – apart from South Island generators, which are also required to pay the HVDC charge. This charge covers the incremental costs of connecting to the transmission network. These generators are not required to pay the common costs of the transmission or distribution network, which is recovered from load customers through the interconnection charge.

In developing the DGPPs, the Ministry of Economic Development recognised the importance of ensuring that the charges paid by distributed generators were substantially similar to those paid by generators connected to the transmission network.

For instance, in its 2003 discussion paper, the Ministry considered two alternative approaches to allocating costs associated with distributed generation, ie:

- a 'deep connection charging' option, where the distributed generator would pay up-front the full incremental costs that will be incurred by a lines network as a result of interconnection; and
- a 'shallow connection charging' option, where the distributed generator paid for the full costs of specific connection assets, and made an ongoing contribution towards the cost of the network.

In the context of comparing the two charging options, the Ministry noted that:[41]

> With shallow connection charging, purpose built generation would have to pay ongoing connection charges and, therefore, would be disadvantaged compared to generation connecting to the transmission network.

The Ministry went on to state that in order for distributed generation to be competitive against transmission-connected generators, owners of distributed generation should pay any reasonable incremental costs arising from their connection to the distribution network, but not a full use-of-system fee. It noted as follows:[42]

> For a small hydro, geothermal, wind or other generation plant purpose built to compete with other generation facilities, to be competitive there needs to be network connection charges that are not significantly different from those charges other new generation connecting to the transmission grid might face. All new transmission grid connected power stations are required to pay for any dedicated lines to connect to the transmission grid. If the desired point of connection with the transmission grid is constrained (at near to or maximum load or the line is of insufficient capacity) the new generation will also be charged for upgrading the constrained portion of the grid.
>
> Given this situation, for new purpose built distributed generation there should be no question that payment is required for any dedicated lines to connect to the lines network and for the extent of network line that needs upgrading for the capacity of the new plant to enter the network system.
>
> …
>
> Once a new generator has paid the costs of connection to the Transpower transmission grid, there are few ongoing charges payable. Rather the costs for maintenance of the transmission grid are payable by lines network companies based on the electricity off-take at grid exit points (the average of the 12 highest peak consumption times over the previous 12 months). In turn, these costs are paid by electricity consumers.
>
> It should be possible similarly not to charge or to have very low charges for the ongoing costs of purpose built distributed generation using the lines network.

In other words, a key principle underpinning the development of the DGPPs was to promote investment in distributed generation through maintaining consistency in the charging arrangements between distributed generation and generators connected to the transmission network. By placing distribution and transmission-connected generation on an equal footing, decisions around the type of generation investment will be more aligned with the relative benefits of each generation option.

5.1.2 The EA's proposal is inconsistent with this rationale

Under the current TPM, removing the DGPPs would lead to a disparity in charging arrangements as between distributed generation and transmission-connected generation. This is because:

- a *transmission-connected generator* would only be required to pay the incremental costs associated with connected to the transmission network (with the exception of South Island generators, which would also be required to pay the HVDC charge); while

[41] Ministry of Economic Development, *Facilitating Distributed Generation: A Discussion Paper*, September 2003, p.20.

[42] Ministry of Economic Development, *Facilitating Distributed Generation: A Discussion Paper*, September 2003, p.20.

- a *distributed generator* would be required to pay the incremental costs associated with connecting to the distribution network, and may also be required to contribute towards the common costs of the distribution network.

In other words, distributed generators would be required to contribute to the common costs of the network, while transmission-connected generators would not.

This outcome would place distributed generation at a competitive disadvantage. Stakeholders may be less inclined to invest in distributed generation if the additional charges lead to a return on investment that is lower than the return on an equivalent generator connected to the transmission network. This would dis-incentivise investment in distributed generation (in favour of transmission-connected generation), and reduce the potential to gain the benefits that distributed generation may provide – an outcome that is inconsistent with the statutory objective of promoting competition for the long-term interests of customers.

The proposed removal of the incremental cost cap also has the potential to exacerbate the impact of the proposal to remove the DGPPs relating to payment of the network benefits associated with the distributed generation. Where there is greater uncertainty that the distributed generator will be paid for the benefits it provides, a simultaneous increase in the costs of connecting to the distribution network rather than the transmission network will further disincentivise the efficient connection of distributed generation.

5.2 The EA's proposal does not account for proposed changes to TPM

As discussed above, the EA's proposal to remove the incremental cost cap under the DGPPs would result in differential cost treatment between transmission- and distribution-connected generation, under the current TPM.

Further, it is not the case that the EA's proposed changes to the TPM will necessarily result in the same charges applying between transmission- and distribution-connected generation, if the DGPPs are removed.

5.2.1 Proposed changes to the TPM

The EA is currently consulting on proposed changes to the TPM. In particular, the EA is proposing to replace the HVDC and interconnection charges with two new charges – an area-of-benefit charge on generation and load, and a capacity-based 'postage stamp' residual charge on load customers only. The connection charge will continue to operate on the same basis as under the current TPM.

If the EA is successful in making these changes, then it will alter the charges that generators connected to the transmission network will pay. In particular, a generator will be required to pay the cost of connecting to the transmission network (an existing charge under the current TPM), as well as an area-of-benefit charge that reflects the benefit the generator receives from certain transmission network assets (a new charge).

However, the EA has provided only scant detail as to how the area-of-benefit charge will be implemented. For instance, the EA has not specified how to identify the areas of benefit, or to determine the extent of the benefit received by market participants including distributed generation, preferring instead to leave these methodological decisions for Transpower to develop. The EA does set out a number of proposals for how benefits can be assessed, but these have the potential to give rise to different outcomes, and may differ from the approach that is ultimately adopted by Transpower.

In the absence of further information on how the area-of-benefit charge will be implemented, and in particular on how the benefits of a transmission asset will be identified and allocated, it is not possible to assess the impact that the proposed changes to the TPM will have on the charges paid by generators connected to the transmission network.

5.2.2 The EA's proposal cannot not take these changes into account

The EA has not demonstrated how its proposal to remove the DGPPs will retain distributed generation and transmission-connected generation on a level playing field, in light of proposed changes to the TPM that will affect the charging arrangements for the latter. For instance, it is not clear that the EA's proposal to remove the DGPPs will lead to an 'area-of-benefit' like charge for distributed generation – given the effort required to develop such a charge, it seems highly unlikely to eventuate in the absence of a clear obligation on distribution businesses to set charges in this manner, and guidance as to how this should be achieved. The EA's current review of the implications of new technologies for distribution pricing methodologies can also be expected to have an impact on the outcome for distribution connection charges, compounding this uncertainty.

Indeed, the EA has sought to amend the DGPPs without fully understanding the arrangements that will apply to transmission-connected generators (given the current uncertainty around how the area-of-benefit charge will be set). This suggests that the EA has not, and further, cannot, assess the implications of its proposal to remove the DGPPs in terms of its impact on the competitiveness of distributed generation (vis-à-vis transmission connected generators). It follows that the EA has not considered all of the implications of its proposal, and moreover, will not be in a position to properly do so until the TPM arrangements are specified in greater detail (including the approach Transpower intends to take in implementing those arrangements) and until the EA has completed its review of the distribution pricing methodology. This suggests that the most appropriate course of action would be for the EA to cease its current consultation on proposed changes to the DGPPs until the proposals for changes to the TPM are further developed and the EA's review of distribution pricing methodology has been completed.

6. The EA's cost benefit analysis

In this section we show that the EA's cost benefit analysis of the ACOT issue is not fit for purpose and does not establish that there will be a significant net benefit from its proposal to remove the DGPPs.

6.1 Overview of the EA's cost benefit analysis

The EA has estimated the economic benefits of its proposal to remove the DGPPs in terms of its ability to address the ACOT issue. In particular, the EA identified and separately modelled four benefits that it expects to arise from its proposal to remove the DGPPs, namely:

1. reducing inefficient, out-of-merit operation of distributed generation and notionally embedded generation that does not reduce or defer transmission investment costs;
2. reducing the scope for retention of distributed generation and notionally embedded generation that does not reduce or defer transmission investment costs and whose retention is not justified by other benefits;
3. reducing inefficient, out-of-merit investment in new distributed generation or notionally embedded generation that does not reduce or defer transmission investment costs; and
4. reducing the allocative efficiency losses associated with consumers paying electricity prices that are higher than is necessary, and altering their consumption decisions as a result.

The EA evaluated these benefits under two different future TPM options, ie:

1. *current TPM*, in which the current TPM remains in force; and
2. *area-of-benefit-based TPM*, in which the current TPM applies for two years, but from April 2019 a new TPM incorporating an area of benefit charge and a capacity-based residual charge is introduced.

We summarise the results of the EA's benefit analysis below:

Table 4: Summary of the EA's analysis of the economic benefits resulting from removing the DGPPs

	Current TPM	Area-of-benefit based TPM
Annual benefits ($million per year)		
Avoiding inefficient, out of-merit operation of distributed generation	0.02 – 0.08	~0
Bringing forward closure of uneconomic distributed generation	0 – 0 .45	~0
Avoiding inefficient, out-of-merit investment in new distributed generation	0.18 – 1.8	~0
Avoiding allocative loss	0.01 – 0.02	0.01 – 0.02
Combined annual benefits	0.22 – 2.37	0.01 – 0.02
NPV of benefits over 15 years ($million over 15 years, in present value terms)		
Expected economic benefits	2.0 – 21.7	0.5 – 4.2
Gross benefit to consumers	232 – 325	46 – 64 (Excludes benefits after April 2019 since EA was not able to quantify this)

Source: EA, Review of distributed generation pricing principles – Consultation paper, 17 May 2016, p.44.

The EA states that its proposal to remove the DGPPs will not result in any economic costs. In particular, it contends that its proposal:

- will not reduce dynamic efficiency, since it will not undermine investor confidence in the stability of the regulatory arrangements, or otherwise have an adverse impact on investor certainty;
- will not change transaction costs, since Transpower already has the capability to assess transmission alternatives, any additional Transpower resourcing would be offset by a reduction in resourcing by the distribution businesses as they will no longer be required to assess and make ACOT payments, and owners of distributed generation will not have additional resource requirements; and
- will not reduce productive efficiency, since Transpower would be expected to contract with owners of distributed generation to defer or reduce transmission investment costs where it is efficient to do so.

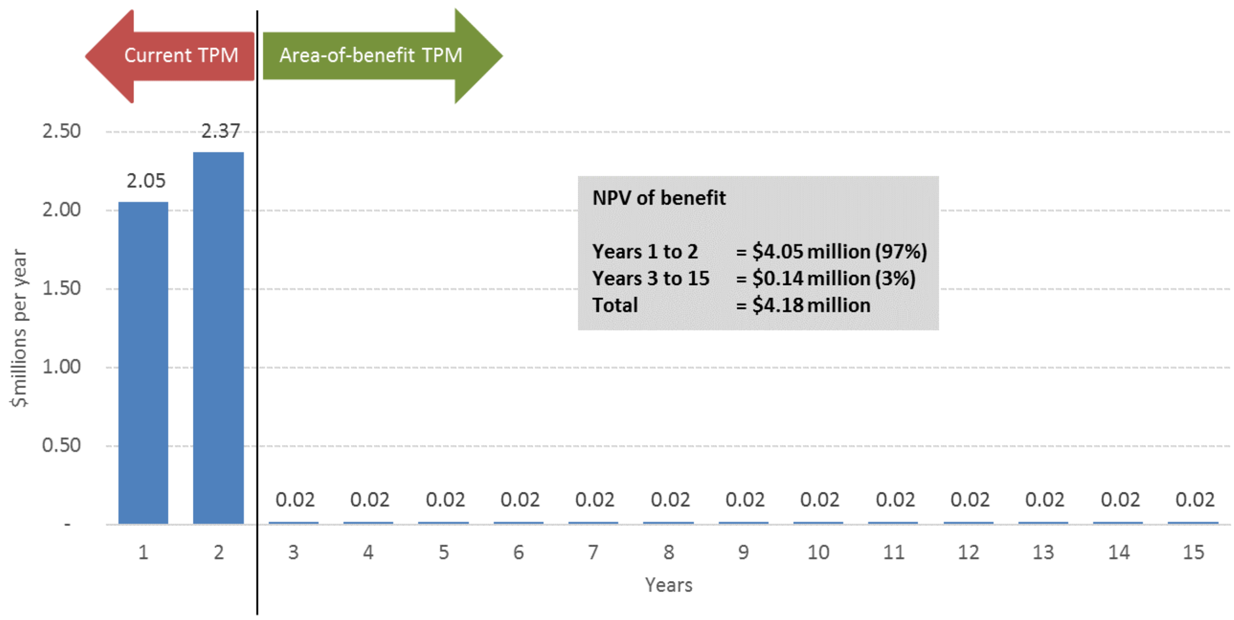
6.2 The benefits estimated by the EA are small

Our summary at Table 4 highlights that the benefits estimated by the EA are very small. At their greatest, they range from $2.0 million to $21.7 million in present value terms over 15 years, ie, around $220,000 to $2,370,000 on average per year.

However, these benefits assume that the current TPM will remain in force, when the EA is also proposing very substantial changes to the TPM. In particular, if the EA is successful in implementing changes to the TPM, the benefits of the proposed removal of the DGPPs are considerably lower, at between $0.5 million and $4.2 million in present value terms over 15 years. Put another way, 80 per cent of the estimated benefit from the proposed changes to the DGPPs are expected to be achieved under the proposed changes to the TPM.

Further, almost all of the benefit calculated under the 'area-of-benefit based TPM' scenario is attributable to the application of the current TPM in the first two years of the analysis, where the EA has assumed that the current TPM will apply – see Figure 1. Specifically, of the $4.2 million benefit that the EA has estimated for this scenario, a total of $4.0 million (or 97 per cent) arises in the first two years under the current TPM, and only $0.14 million (or 3 per cent) arises in years 3 to 15 under area-of-benefit TPM. Put another way, if the EA's area-of-benefit TPM proposal is introduced, the economic benefit expected to be achieved from removing the DGPPs is exceedingly small.

Figure 1: Estimated annual benefit under the area-of-benefit-based TPM scenario



In our opinion, if these estimates do indeed reflect the extent of the benefit that the EA believes will come out of its proposal following completion of the consultation process for distributed generation, the EA should consider halting the process altogether. By the EA's own analysis, the vast majority of the expected benefits from the EA's proposal will be achieved if the EA is successful in adopting its area-of-benefit TPM. Of the remaining estimated benefit, the cost of EA staff time spent in the process of consulting on the proposal seems likely to exceed the lower bound of the range of expected benefits – even before the costs incurred by all relevant non-EA participants are taken into account. This would suggest that the *net* benefit of the proposal (ie, expected benefits *less* expected costs, including costs associated with developing the proposal) would be negative.

6.3 The EA's method for estimating benefits is not fit for purpose

The EA's approach to quantifying the benefits of its proposal to remove the DGPPs includes a large number of variables for which the value is unknown and so has been established only by means of an EA assumption. These are set out in the table below with the EA's assumed value or range of values.

Table 5: Summary of assumptions adopted by the EA in quantifying benefits

Parameter	EA's assumption
Avoiding inefficient, out of-merit operation of distributed generation	
The proportion of liquid-fuelled investment that is inefficient, in that it does not defer or reduce network costs	30% - 70%
The percentage reduction in inefficient liquid-fuelled investment due to the EA's proposal	50% - 80%
Bringing forward closure of uneconomic distributed generation	
The proportion of current distributed generation receiving ACOT payments that is inefficient, in that it does not defer or reduce network costs	70%
The proportion of inefficient current distributed generation that is only economic due to ACOT payments	0% - 10%
The percentage reduction in uneconomic current distributed generation retained under the EA's proposal	80%
Avoiding inefficient, out-of-merit investment in new distributed generation	
The proportion of future investment in distributed generation that is inefficient, in that it does not reduce network costs	30% - 70%
The proportion of inefficient future distributed generation that is less cost-effective than the best grid-connected alternative	30% - 80%
The percentage reduction in cost-ineffective future distributed generation as a result of the EA's proposal	40% - 65%
Avoiding allocative loss	
The price elasticity of demand	-0.26
The additional cost to consumers per annum to fund ACOT payments without receiving an associated benefit	$25 - $35 million

In the absence of an analytical or empirical basis for estimating these variables, there is no factual or empirical support for the benefits estimated by the EA. In other words, the size of the benefits ascribed to the EA's proposal are simply guesses, and should be treated with great caution in terms of justifying a case for change. A more robust process is necessary to motivate changes to the existing regulatory framework.

In addition there appear to be some inconsistencies with the assumptions that the EA has made in relation to the cost benefit analysis for its DGPP proposal and the cost benefit analysis undertaken for the changes proposed to the TPM. The EA's cost benefit analysis of its proposed changes to the DGPPs assumes that benefits will arise from discontinuing operation of embedded diesel generators. This appears to conflict with the cost benefit analysis that Oakley Greenwood conducts of the TPM, which calculates net benefits from continuing to operate the existing fleet of distributed generation. Specifically, Oakley Greenwood estimates that the unit costs of continuing to operate distributed generation amount to $32,632 per MW, which is less than its estimate of network LRMC for load of $34,611 per MW. The difference between these costs gives rise to a net benefit of continuing to operate distributed generation of $18.5 million over 20 years.

6.4 The EA has not accurately estimated costs

The EA concludes that the economic costs of its proposal to remove the DGPPs are zero because its proposal will not result in any material inefficiencies, or in any additional transaction costs.

In our opinion, this statement is at odds with any reasonable analysis. We explain in sections 3 and 4 that the proposed arrangements are likely to result in lower than efficient levels of distributed generation on account of the difficulties in obtaining ACOD and ACOT payments. In particular, it is expected that the proposal:

- will lead to the closure of some existing distributed generators – existing generators will need to negotiate new connection agreements with Transpower and the distribution networks for the benefits they provide. However, network businesses have limited incentives to negotiate ACOD and ACOT payments, and the asymmetry of information and bargaining power between the distributed generator and the network will likely mean that any negotiated connection agreement will favour the network and not accurately reflect the size of the avoided network costs attributable to the generator. If this results in ACOD and ACOT payments that are substantially lower than the level of current payments, some distributed generators would be expected to leave the market; and
- will deter efficient investment in new distributed generation – the obligation to negotiate discrete connection agreements for each distributed generation project will create uncertainty for investors on the likely terms and conditions of connection, giving rise to disputes and also the potential that efficient distributed generation projects will not proceed because of a failure to obtain a connection agreement. The absence of a robust institutional framework for considering non-network alternatives to network investment will exacerbate this problem, since it may mean that efficient distributed generation projects may not be fully explored by network businesses when making network planning decisions.

Further, it is likely that the resource requirements for the network businesses and distributed generators will increase as a result of the EA's proposal. At present, resourcing requirements are expected to be low since normal practice has been for distribution businesses simply to pass through savings in transmission charges to distributed generators. However, removing the DGPPs and requiring distributed generators to negotiate the terms and conditions of their connection agreement with Transpower and the relevant distribution business will increase the amount of time and effort required to reach an agreement, while also increasing the prospect of dispute. These factors will likely increase resourcing requirements vis-à-vis current levels. In addition, the removal of the DGPPs will result in an additional requirement to renegotiate current contractual arrangements for existing distributed generators, resulting in additional resources for no apparent benefit, given that the investments themselves have already been made.

It follows that the EA's proposal will lead to additional resource costs being incurred. These costs arise from lower than efficient levels of distributed generation, and higher resource requirements for network businesses and distributed generators. Once these costs are factored in, the net benefit of the EA's proposal would almost certainly fall to become negative.

7. Best practice principles for regulatory change

The EA's proposal will lead to an ex-post adjustment to the returns that can be expected by owners of existing distributed generation. This is inconsistent with best practice principles for regulatory change. It will increase the perception of regulatory risk, and hence the cost of capital, in the electricity market.

7.1 Regulatory risk

Regulatory arrangements are critical to determining the basis for cost recovery and the risk of not recovering the cost of an investment. Changes in regulatory rules that substantially affect the basis of, and prospects for, investor cost recovery need to be handled with a great deal of care and sensitivity to avoid a significant reduction in investor confidence. This includes changes that result in a transfer of wealth between participants in the electricity sector.

Certain decisions can reduce the prospect of investors' ability to fully recover their costs, including the return on and of capital for a particular project. This could involve, for example:

- an unanticipated change in the application of existing regulatory rules, processes or criteria for assessing a regulated firm's cost recovery opportunities; or
- the introduction of new or different rules that affect the prospects for cost recovery of existing investments.

Unexpected significant changes in regulatory arrangements will reduce investor confidence in the stability of future arrangements. This is a form of regulatory risk, since it reflects the risk of the regulator reneging on an implicit agreement with investors. Ultimately, a reduction in investor confidence in the stability of regulatory arrangements will increase the cost of raising capital for deployment in the electricity sector.

The need to ensure that changes in regulatory arrangements minimise the perception of risks arising is a core principle of best practice economic regulation.

7.2 Effects of regulatory risk

The long term interests of customers will best be served by regulators acting so as to minimise the uncertainty associated with the returns to capital. Investing in infrastructure involves substantial upfront investments and uncertain future revenues. Regulatory authorities with a track-record of making substantial and/or ex-post adjustments that affect investors' returns will increase the level of unpredictability in the regulatory environment and, in so doing, substantially increase the perceived risk of investing.

This is an impact which is well recognised by the EA:[43]

> Regulators are always able to transfer wealth, but if they do so it has to recognise there will be a cost. The cost will be in the willingness and terms on which parties will invest in generation capacity in the future and in other sectors of the economy.

An increase in perceived downside risk will increase the cost of capital because investors will require a higher rate of return to compensate them for the increased risk. This, in turn, affects the entry decisions of potential investors, since capital investment in the electricity sector (and potentially other regulated industries) will not be so readily forthcoming unless investors expect to derive a return at least sufficient to recover the cost of capital. It follows that an unnecessary increase in regulatory risk may deter or delay investment.

[43] Electricity Authority, *The Economics of Electricity*, 4 June 2013, para 63.

7.3 Relevance to the EA's proposal

The EA's proposal to remove the DGPPs would have the effect of reducing the return on investments for existing distributed generation. This would result in a substantial, ex-post transfer of wealth from existing investors in distributed generation to other industry participants, thereby increasing regulatory uncertainty, and correspondingly raising the level of risk perceived by investors.

An increase in regulatory risk will increase the cost of capital in the New Zealand electricity industry because investors will require a higher rate of return to compensate them for the increased level of risk borne. This will, in turn:

- increase the cost of operation in the electricity industry;
- increase electricity prices;
- result in under-investment; and
- dampen the effectiveness of price signals.

An increase in the cost of capital reduces efficiency since the provision of future electricity services becomes more expensive. It may also reduce or delay efficient investment, since capital investment in the electricity sector may be less forthcoming if investors do not expect to derive a return at least sufficient to recover the higher cost of capital. This neither promotes the reliable supply of electricity nor the long-term benefit of consumers.

The EA has previously recognised the effect of ex post wealth transfers – such as those arising from removing the DGPPs – on investment and, ultimately, the welfare of consumers. It stated that:

> Ex post transfers of wealth… in the case of transfers to consumers, is likely to have an undesirable chilling effect on the willingness of parties to invest. This is definitely not a long-term benefit to consumers.[44]

The EA will best promote the long term interests of customers by acting so as to minimise the regulatory risk and uncertainty associated with the returns to capital. Amending the payment arrangements to existing distributed generation in a way that increases regulatory risk in the New Zealand electricity industry will not promote the efficient operation of, or reliable supply by, the electricity industry and will ultimately not benefit consumers. It follows that, contrary to the EA's analysis, unexpected changes to the payment arrangements for existing distributed generators will not promote its statutory objective.

The EA points out that the level and basis of ACOT payments has not been a 'settled' area of policy. It notes that the arrangements between distributors and distributed generation owners have been affected by several regulatory changes in recent years, and that transmission pricing structures (which have affected some forms of ACOT payment) have been under continuous change or review for more than two decades. In its assessment of the context for its proposals, the EA characterises its proposal as but one more step in an area that has already been subject to extensive review and change.

These contentions are at odds with recorded history.[45] Although first legislated in 2007 in the *Electricity Governance (Connection of Distributed Generation) Regulations 2007*, the remuneration of distributed generators on the basis of reduced transmission charges (ie, by reference to ACOT payments) has been in place for decades and is a longstanding element of the regulated environment for electricity in New Zealand. Further, signals to reduce peak demand via distributed generation date back to the 1950s, when the bulk supply tariff was levied on local power boards on the basis of peak demand.

In any case, a contention that regulation is not settled because it has been under review for two decades is not a stance that is likely to promote confidence in any (existing or proposed) regulatory approach. Rather,

[44] Electricity Authority, *The Economics of Electricity*, 4 June 2013, para 43.

[45] Strata Energy Consulting, *Report on the history of the Bulk Supply Tariff and Transmission Pricing in New Zealand*, January 2014.

such statements increase the perception of regulatory risk, and so are likely to lead to sub-optimal investment outcomes – an adverse impact on dynamic efficiency.

If the EA were to conclude that the DGPPs should be amended, then it will be critical to take account of the financial interests of existing investors in distributed generation. In order to minimise the adverse effect of increased regulatory risk, the government should ensure that existing investors are sufficiently compensated for departures from the returns they would reasonably have anticipated under the existing, long-standing regulatory arrangements. The cost of any such compensation should also be taken into account in the analysis underpinning any decision to amend the scheme.

7.4 Change management measures

Reforms that affect the returns received by an investment will generally alter future investment decisions but have a much lesser effect on the behaviour of existing stakeholders. For example, regulatory reforms that reduce the returns earned by a particular type of investment will discourage new investment, but generally do not result in the infrastructure facilities operated by existing participants shutting down. Such reforms therefore give rise to greater regulatory risk by imposing an ex-post windfall loss on existing investments.

The adverse effects of regulatory risk mean that best-practice regulators generally seek to minimise risk through the inclusion of 'change management' arrangements as part of a package of measures that are likely to have an adverse effect on the financial position of existing parties operating within and subject to a particular regulatory framework.

The principal objective of such arrangements is to minimise the effect of the changes to existing investors, without compromising the long-term efficiency benefits of the reforms. In other words, change management arrangements seek to minimise the financial impact of the reforms on existing investments while still ensuring that the amended price signals are able to guide new investments. The inclusion of effective change management arrangements enhance the stability and predictability of the returns of investors, and so foster an environment conducive to investment in long lived assets.

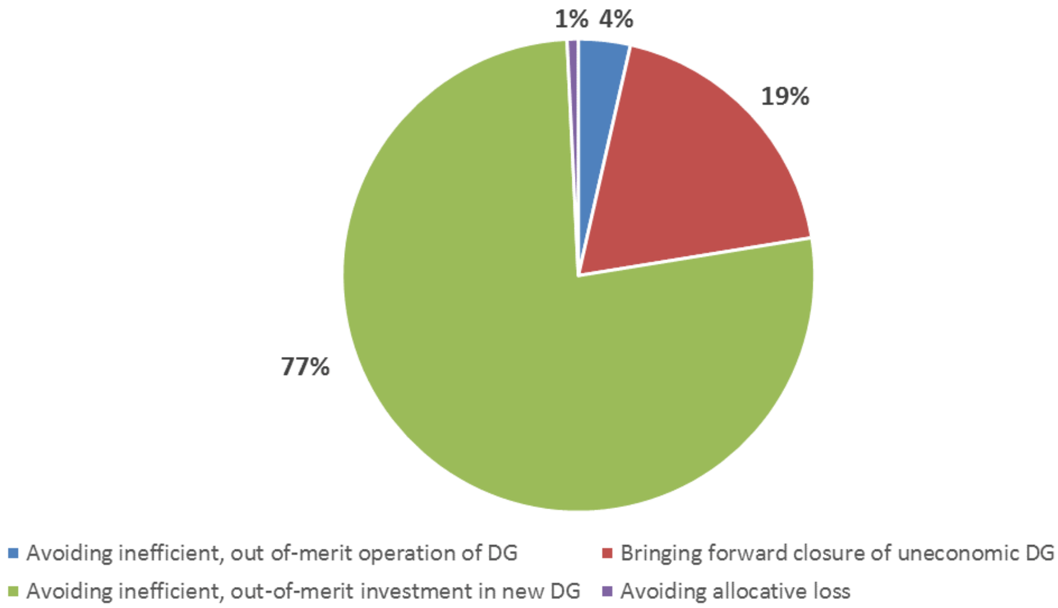
On this basis, where the EA adopts a position that the current regulatory settings no longer promote the principles of dynamic efficiency, an appropriate response is to change those settings for new investments only. The EA should be extremely cautious in adopting an approach that effectively reverses the regulatory settings for sunk investments.

Alternative approaches that have a less adverse impact on dynamic efficiency may involve:

- applying any proposed changes to new investments in distributed generation only; or
- adopting a grandfathered or phased transition for existing distributed generation.

Relevantly, these alternative approaches would still promote the majority of the benefits identified by the EA as arising from the removal of the DGPPs. In particular, Figure 2 below shows that 77 per cent of the annual benefit estimated by the EA under the best case scenario is attributable to avoided inefficient *new* distributed investment. An alternative approach that applies only to future distributed generation would still capture these benefits. In addition, such an approach would lower the costs associated with the EA's proposals, by avoiding the resource costs associated with the re-negotiation of existing contracts.

Figure 2: Proportion of annual benefits from removing DGPPs estimated by EA, best case scenario



7.5 Summary

Removing the DGPPs for existing distributed generators will increase regulatory risk and, in turn, the cost of capital in the New Zealand electricity industry. Since the EA has not taken into account this 'cost,' it has fundamentally overestimated the net benefits of the proposal.

Further, since the EA did not consider alternative options that will not result in regulatory risk – such as applying the new arrangements to new investments alone, or establishing a phase-in for existing distributed generation – it did not have regard to the full range of relevant factors in formulating its proposal.

A1. Investment in distributed generation in Australia

In this appendix, we provide further detail on circumstances where distribution businesses in Australia have adopted distributed generation solutions in preference to implemented network options to address particular constraints or issues in their network.

Table 6: Examples of distributed generation investment in Australia

Project	Project description
SA Power Networks, South Australia	
Bordertown Substation (south east region of SA)	• In 2010, SA Power Networks identified projected network limitations at Bordertown substation. Bordertown substation transformers were forecast to be overloaded at peak times by summer 2013/14, voltages under peak condition were expected to be inadequate in 2015/16, and the capacity of a connection was forecast to be exceeded in 2017/18. • Through a Request for Proposals process, SA Power Networks established that a non-network solution may be a viable alternative to network augmentations • SA Power Networks determined that the most economic option was the option that had the highest 'total combined value' – the summation of direct costs associated with the augmentation and the benefits associated with reduction in losses or improved customer reliability • Under this criteria, SA Power Network determined the preferred option would be to employ embedded generation for peak lopping, in order to delay system upgrades, which they estimated would cost more than A$10 million over several years • SAPN engaged Vibe Energy to provide third party support through an embedded generator at Bordertown
Ausgrid, New South Wales	
Arncliffe Zone	• In 2012, Ausgrid identified a capacity constraint was expected to occur in summer 2013/14 at Arncliffe zone substation while conducting an area study • Ausgrid concluded that it may be cost effective to postpone a supply-side solution by implementing demand management strategies and invited responses from interested parties • Ausgrid carried out an investigation of non-network options and found that the first year of required demand reduction has already been achieved through changes in business activity in the area • The most cost effective solution for load reduction was found to be relocatable leased diesel generators, which can reduce peak demand in Arncliffe area in 2014/15 and 2015/16, allowing for a one to three-year deferral • The estimated project cost ($2013) to Ausgrid would be approximately A$368,000 for one summer season (ie, summer 2014/15) and A$694,000 for two (ie, summer 2014/15 and 2015/16), while the demand reduction value for this period was A$710,000
North Western Pennant Hills Zone	• In 2010, Ausgrid identified a need for a A$3.75 million investment that involved laying a new 11kV cable from Pennant Hills zone substation to the north of Cherrybrook while maintaining required network performance from summer 2011/12 to summer 2012/13 • Ausgrid identified that it would be possible to defer the investment until after summer 2012/13 by implementing demand reductions of 0.55MVA in summer, or until after summer 2013/14 by implementing demand reductions of 0.82MVA in summer • Ausgrid determined that a relocatable generator would achieve a sufficient demand reduction to defer the proposed investment • A 500kVA generator was commissioned for summer 2010/11 and summer 2011/12, and a 8000kVA generator was commissioned for summer 2012/13

	• A full feeder compliance review was completed for the Pennant Hills zone substation in December 2012, and found that a new 11kV cable was no longer necessary and the relocatable generator was subsequently decommissioned • The implementation of a demand management project, which cost A$650,000, allowed Ausgrid to avoid a A$3.75 million supply side investment
AusNet Services, Victoria	
Euroa - BN1 22kV feeder	• In 2013, AusNet Services identified the need to reduce load at Euroa by 1.56 MW • AustNet Services established a fleet of four mobile diesel generators (1MW each, with support to the grid of 800kW) that can be connected to the distribution network to reduce network loads, and alleviate constraints at times of peak demand • The deployment of two mobile generators to support the Euroa BN1 22kV feeder in 2013/14 allowed A$8.2 million of capex to be deferred
Traralgon	• In 2012, AusNet Services negotiated with a non-network provider, NovaPower, to install 10MW of gas-fired embedded generation at Traralgon, which became operational in 2013 • The embedded generation allowed deferral of the augmentation of a new 220/33 MVA Zone substation transformer for at least five years • The advantages of deferral of such high cost projects identified by AusNet Services are that additional time allows more accurate consumption forecasts and as a result, better planning decisions • This was among the demand management solutions that allowed AusNet Services to defer A$11 million of capital augmentation expenditure (as at 30 April 2015)
Ergon Energy, Queensland	
Southern Atherton Tablelands	• In 2012, Ergon Energy supplied the Southern Atherton Tablelands via three 22kV feeders from the Atherton 66/22kV substation, and identified emerging limitations in the electricity distribution network • Ongoing customer load growth resulted in an aggregate customer load that exceeded the capacity that could be supplied by two 22kV feeders, if one feeder experienced an outage • Ergon Energy identified that at a minimum additional 4.9MVA capacity at 22kV was necessary to maintain acceptable reliability for supply to the area • Ergon Energy published a Request for Information relating to the anticipated network constraint, and received two external and one internal submission • Ergon Energy decided to implement a customer embedded generation (at the Milanda Dairy Centre) to defer the establishment of a new 66/22kV substation until November 2019, as it was found to be the least cost solution over the 15-year period of analysis in all scenarios considered • The employment of embedded generation allowed a network augmentation of A$17.3 million to be deferred four years
St George Area	• Ergon Energy is responsible for electricity supply to the St George area in Southwest Queensland via a single 194 km 66kV sub-transmission feeder from the Roma Bulk Supply Point • It identified emerging limitations in the electricity distribution network supplying the St. George area – the peak load on the Roma-St. George 66kV lines was above a regulatory threshold of 15MVA, which triggered work to enhance security of supply • In 2012, Ergon Energy published a Request for Information for this constraint and received 11 submissions • Ergon Energy undertook an economic analysis to find the present value cost of the alternative options over 20 years (2013-2033) under eight different scenarios • The economic analysis revealed that the option with the lowest net present cost under all scenarios would be embedded diesel generation • As a consequence, Ergon Energy decided to implement a tender for third parties to provide network support via an embedded generator.

Sources: SA Power Networks, 2013, RFP 002/10 – Overload of Bordertown substation; Ausgrid, 2010, Demand management investigation report: North western Pennant Hills zone 11kV; Ausgrid, 2013, Demand management investigation report: Arncliffe; Ausgrid website: https://www.ausgrid.com.au/Common/Industry/Demand-management/Demand-Management-Projects/Projects-to-have-DM-potential.aspx; AusNet Services, 2014, Energy insights: Demand management and smart network technologies; AusNet

Services, 2015, AusNet Electricity Services Pty Ltd: Electricity distribution price review 2016-20; Ergon Energy, 2013, Regulatory test – Final recommendation report – Emerging distribution network limitations in the St George Area; Ergon Energy, 2014, Regulatory test – Final recommendation report – Proposed deferral of a new 66/33kV substation at Malanda.

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