Distributed Generation Pricing Principles

Issues paper

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ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

Distributed generation (DG) is essential to New Zealand's future electricity system. Whether the distributed generation is from large power plants, rooftop solar panels or household batteries, having more localised electricity sources directly connected to the network is a smart and effective way to reduce congestion, strengthen security of supply and lower prices for consumers.

The number of distributed generators is growing in New Zealand, as is their capacity. The Electricity Authority Te Mana Hiko (the Authority) wants to support more DG – where it is efficient – so all New Zealanders can reap the benefits it brings.

This issues paper reviews the regulatory arrangements for distribution price signals for DG. In our view, the distributed generation pricing principles (DGPPs) in Part 6 of the Electricity Industry Participation Code 2010 (Code) may no longer be fit for purpose, and it is timely we consider how the regulatory arrangements should be updated to drive more efficient investment in DG.

Under the current rules, distributors are prevented from recovering more than incremental costs from DG, which may prevent distributors from efficiently planning for future connections. This incremental cost limit may also be exacerbating 'first-mover disadvantage', where the first distributed generator to connect to a network faces significantly larger costs than those who follow. First-mover disadvantage may prevent efficient investment in DG from happening in the first place. This means consumers miss out on lower prices and strengthened security of supply that efficient DG can bring.

In this issues paper, we consider four possible options for addressing the incremental cost issue. The options are retaining the DGPPs (the status quo), making minor changes to the DGPPs, removing the DGPPs and relying entirely on market solutions, or a comprehensive overhaul of the DGPPs. Our current preferred approach is the latter, though we have not yet defined how the DGPPs would be revised, or whether they would remain part of the Code once revised. The key change would be that the revised DGPPs would be less prescriptive than the existing DGPPs and may involve including greater flexibility by removing the incremental cost rule.

We invite stakeholders to share their perspectives on which of the four options will best promote the long-term benefit of consumers.

This issues paper has been incorporated in a consultation package that includes the 'Requiring distributors to pay a rebate when consumers supply electricity at peak times' consultation paper. In this related consultation paper, the Authority proposes developing a principles-based approach for distributors to price injection from DG by customers on standard contracts (ie, mass-market customers). That proposal does not apply to non-standard customers, such as utility-scale generators and industrial customers with their own generation. While these two papers address slightly different issues, we have released them as part of a package to help submitters to understand our thinking on both issues, given they both relate to pricing for DG.

This paper also reviews whether distributed generators currently face efficient, cost-reflective price signals for transmission costs. We consider that they do. In our view, the Authority's wholesale market dispatch and price discovery mechanism efficiently rewards DG's contributions towards avoiding transmission costs, supporting grid reliability, and delaying or avoiding transmission investment – all of which helps keep power bills down. We have not identified any changes to the regulatory arrangements in relation to transmission costs that would be in the long-term interests of consumers, but we welcome your views on this.

Once all feedback has been analysed, and if we consider that change is required, we expect to develop a proposed Code amendment for consultation. The proposed Code amendment could be one of the options identified in this paper, or another option not yet identified. Your feedback will help determine which Code amendment we should propose, and inform our work to improve the regulatory framework, so it can better realise the potential of DG to operate for the long-term benefit of all New Zealanders.

1. The distributed generation pricing principles

1.1. The main regulatory mechanism affecting distribution prices for distributed generation (DG) is the distributed generation pricing principles (DGPPs) in Part 6 of the Electricity Industry Participation Code 2010 (see box below).

Box 1: Excerpt from DGPPs (clauses 2 of Schedule 6.4 of the Code), and clause 1.1(1) of the Code, definition of incremental costs)

> Charges to be based on recovery of reasonable costs incurred by distributor as a result of connecting the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs.
>
> … connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the **distributed generation** …
>
> **incremental costs**, for the purpose of Part 6, means:
>
> (a) the reasonable additional costs (which include any reasonable additional transmission costs) that an efficient **distributor** would incur in providing **electricity** distribution services to **distributed generation**; minus
>
> (b) the distribution costs (which do not include any transmission costs) that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**.
>
> See Appendix B for the full principles specifying calculations, costs and cost shares.

1.2. The DGPPs were first introduced in the Electricity Governance (Connection of Distributed Generation) Regulations 2007 to "facilitate the use of DG by ensuring that it does not face undue barriers in connecting to lines".[1] The Electricity Industry Act 2010 incorporated the regulations in the Code.

1.3. When the DGPPs were first introduced, the expectation was that DG would:[2]

(a) "play an increasingly important role in meeting electricity demand as the cost of smaller-scale and new renewable technologies continues to decline"

(b) "improve security of supply by creating diversity of fuel types, locations and technologies"

(c) "reduce the need for transmission and distribution upgrades".

1.4. The DGPPs, along with regulated terms of access, were intended to:

(a) overcome differences in bargaining power between distributors and investors in DG[3]

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[1] Government Policy Statement, 30 October 2006, paragraph 110. https://library.victoria.ac.nz/databases/nzgazettearchive/pubs/gazettes/2006/2006%20ISSUE%20123.pdf

[2] Government Policy Statement, 30 October 2006, paragraph 109.

(b) ensure a level playing field between investment in DG and investment in grid-connected generation.

1.5 In 2016, the Authority consulted on an option to remove the incremental cost limit because "while it may be efficient for owners of DG not to contribute to common costs in some situations, it is unclear why this would be efficient in all cases".[4]

1.5. At the time, the Authority decided against removing the incremental cost limit because of the risk that efficient investment and operation of DG could be impeded if:

(a) distributors increased charges to distributed generators

(b) grid-connected generation faced lower connection or use of system charges.[5]

The focus of this paper

1.6. This paper focuses on the requirement in the DGPPs that distributors are allowed to recover no more than incremental costs from DG (the incremental cost limit). This is discussed in section 2 of this paper.

1.7. Potential options for addressing this issue are discussed in section 3.

1.8. We also reviewed whether pricing arrangements are efficient with respect to signalling *transmission* costs to DG. This is discussed in section 4.

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4 Electricity Authority, Review of distributed generation pricing principles: Decision and reasons, 6 December 2016, p.18

5 At the time, the transmission pricing methodology was being reviewed but the status quo was that grid-connected generation in the North Island paid connection charges and South Island generation paid connection charges plus HVDC charges.

2. The incremental cost limit leads to poor outcomes for consumers

2.1. The DGPPs allow distributors to recover no more than incremental costs from DG (the incremental cost limit). In this section we consider issues with the incremental cost limit rule in the DGPPs. We discuss how the incremental cost limit may lead to several efficiency and network planning problems, including:

(a) increasing the risk of incentivising excessive investment in DG, which would raise consumers' costs of electricity supply by:

(i) favouring investment in DG over grid-connected generation

(ii) passing common costs of managing the distribution network on to consumers

(b) increasing the risk of impeding efficient investment in DG, because it dilutes incentives for distributors to dedicate resources to hosting DG by:

(i) imposing limits on cost-sharing that discourage the funding of efficiently sized investments

(ii) imposing limits on recovering common costs that reduce incentives on distributors to dedicate resources to planning for, and effectively managing, the costs of DG

(c) potentially limiting distributors' ability to use efficient prices to:

(i) broaden the base over which revenue is recovered and reduce distortions to network use

(ii) signal costs using pragmatic approaches involving approximations.

2.2. The incremental cost limit may be exacerbating 'first-mover disadvantage', where the first DG to connect to the network faces significantly larger costs. This is likely to lead to increased costs for consumers. Furthermore, if the incremental cost limit discourages effective investment in DG, it could also have a negative impact on the security of the energy supply.

The DGPPs restrict distributors from charging more than incremental cost

2.3. The charges distributed generators pay distributors for use of the distribution network are regulated (for those on regulated terms) by the DGPPs in Schedule 6.4 of the Code. The DGPPs came into effect in 2007, and later moved to Part 6 of the Code.

2.4. Amongst other things, the DGPPs stipulate that distributors may recover no more than incremental costs from DG (the "incremental cost limit"). Schedule 6.4 of the Code, principle 2 provides:

> Charges to be based on recovery of reasonable costs incurred by distributors to connect the generator and to comply with connection and operation standards within the network and must include consideration of any identifiable avoided or avoidable costs.

2.5. Schedule 6.4 of the Code, principle 2(a) provides:

> […] connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation:

2.6. Incremental costs are defined in clause 1.1(1) of the Code to mean:

> (a) the reasonable additional costs (which include any reasonable additional transmission costs) that an efficient distributor would incur in providing electricity distribution services to distributed generation; minus
>
> (b) the distribution costs (which do not include any transmission costs) that an efficient distributor would be able to avoid as a result of the electrical connection of the distributed generation

2.7. The DGPPs effectively place an upper limit on distribution charges paid by distributed generators. The DGPPs only apply to distributed generators on regulated terms, which generally means when the parties have not contracted out of these terms. Distributors may not charge a distributed generator for any costs not directly attributable to the activity of that distributed generator, so they cannot be charged for common costs unless the distributed generator agrees.

The incremental cost limit imposes a real constraint on costs recovered from DG

2.8. The DGPPs make it harder to host DG by limiting how distributors can recover costs related to DG.

2.9. Distributors may only charge a distributed generator for actual costs incurred to provide that generator with services. An Authority determination, applying the DGPPs, found that this:[6]

(a) "means a distributor cannot charge a distributed generator for any capital, operating, or maintenance costs the distributor is not reasonably likely to incur as a result of the connection of the distributed generator's distributed generation"

(b) "limits the connection charges a distributor may recover from a distributed generator for distinct capital expenditure by the extent to which the expenditure is attributable to the distributed generator's actions or proposals".

2.10. Other examples of costs that cannot be recovered under the incremental cost limit are:

(a) investment costs of any assets already in use, unless:

i. the existing user is a distributed generator and

ii. the assets are less than three years old[7]

6 Anonymised_determination_of_connection_charges_payable_under_schedule_6.3_of_the_Code.PDF

7 Schedule 6.4 of the Code, principle 2(m).

iii. cost incurred serving distributed generators as a group or class of customers, as opposed to individually.

(b) any other operating expenses incurred by distributors in providing lines services.

2.11. As described in paragraph 2.5, the incremental cost related to distribution refers to the costs that an efficient distributor can avoid due to the electrical connection of DG. The general nature of the incremental cost definition may lead to various interpretations and diverse examples of how distributors identify incremental costs. For example, while some distributors may limit their definition of incremental cost to network costs, other distributors may seek to include consequential costs relating to factors such as frequency keeping and voltage support within the definition of incremental cost. Some stakeholders consider this practice to be a barrier to timely investment in generation.

Q1. Do you have a view on the definition of incremental cost that is contained in the Code? Should it be more tightly defined to include only network costs and to exclude consequential costs relating to factors such as frequency keeping and voltage support? Would this lead to more timely generation build and lower energy costs?

Distributed generators pay for fewer costs than grid-connected generators

2.12. The incremental cost limit creates an artificial advantage for DG, compared to the allocation of transmission costs for grid-connected generators.

2.13. Under the incremental cost limit, distributed generators that connect to existing distribution network assets are only expected to pay for:

(a) their dedicated connection assets [8]

(b) costs of upgrading or adding other assets if those upgrades or additions are needed <u>because</u> of the new generator [9]

(c) a share of connection costs already funded by a distributed generator, that are refunded to the existing distributed generator[10]

(i) if those costs were incurred within 36 months from the initial connection of the existing distributed generator[11]

(ii) in proportion to the generator's share of maximum peak generation.[12]

2.14. Distributed generators on the regulated terms that require new connection assets will typically have to pay for those assets upfront, although there may be cost-sharing with distributors if there are mutual benefits from the connection.[13]

8 Schedule 6.4 of the Code, principle 2(a).
9 Schedule 6.4 of the Code, principle 2(a).
10 Part 6. Schedule 6.4, 2(k)(l)(m)
11 Part 6. Schedule 6.4, 2(m)
12 Part 6. Schedule 6.4, 2(i)(i) and(ii)
13 Powerco has a cost-sharing agreement with Lodestone Energy for a utility-scale solar project south of Whitianga (Lodestone Energy – Utility scale distributed generation (DG)).

2.15. Grid-connected generators, by comparison:

(a) pay for a portion of costs of interconnection assets through benefit-based charges

(b) pay for the full costs of connection assets through investment agreements with Transpower, and for the renewal of connection assets (including shared connection assets) through transmission charges

(c) to the extent they are also a load customer, a grid-connected customer pays for residual charges.

2.16. These costs are typically substantial for grid-connected generators. For example, Transpower's transmission pricing for the 2023/24 pricing year shows the major electricity generating customers were to pay $93.5 million in benefit-based charges, a form of use-of-system charges.[14]

2.17. In principle, we acknowledge that consumers may benefit from lower network charges for DG if new connections reduce the costs of supplying them with electricity. Alternative approaches that allow generators to be charged for a share of existing costs risk deterring the investment in the first place and making electricity more expensive than it needs to be.

2.18. However, the risk to consumers from the current arrangements is that electricity supply costs increase because:

(a) investors favour DG projects that have higher economic costs than grid-connected alternatives, whether in terms of scale or technology.

(b) investors favour connecting to distribution networks even if this means higher network costs on average, compared to if they had connected to the grid.

Investors in new assets are discouraged from accommodating future demand

2.19. Distributed generators who pay for new connection assets benefit from incremental cost pricing as their share of network costs are capped. However, limits on connection cost-sharing may subsequently disadvantage these first movers.

2.20. This disadvantage is partly distributional,[15] but it also has efficiency implications. First-mover disadvantage can cause inefficient outcomes if it means that, in the absence of cost-sharing, a party is unwilling to bear the cost of new assets that may otherwise make economic sense. In other words, where investment decisions are yet to be made, a cost-sharing provision can promote efficiency and security of supply by encouraging investment that would not otherwise occur.

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14 Customer prices for 2024/25 (as notified in December 2023), available at [Grid Prices | Transpower](). Sum of charges for Contact Energy, Genesis Energy, Manawa Energy, Mercury, and Meridian Energy.

15 The first mover would be better off if subsequent generators shared connection costs. But when the costs have already been incurred, there is nothing to be gained to anyone else from cost-sharing. Although perceptions of unfairness may mean difficult conversations for distributors, there is no direct consequences to consumers unless cost-sharing has some effect on efficiency or the reliability of supply of electricity.

2.21. To illustrate this point, an investor may consider funding an upgrade to a substation if there is immediate demand to accommodate a new generator. However, there will be efficiencies for the investor if more generators want to connect in the area in coming years. If the investor anticipates future demand and increases the upgrade to accommodate more generators in the future, then the costs per generator and over time will be lower than if the upgrade is made only for the immediate need.

2.22. If cost-sharing is permitted, the investor may be more incentivised to make the larger and lower average cost investment. In this scenario, the investor is incentivised to consider the costs and benefits of oversizing the upgrade.

2.23. The investor in this example, is also incentivised to weigh the costs of connection charges for any new distributed generators that want to connect in the future. If the charges are too high, they may not recover their costs.[16]

Current incremental cost limit stands in the way of efficient arrangements

2.24. The current incremental pricing limit discourages these sorts of arrangements. First-mover investors cannot recoup their costs except:

(a) if new distributed generators seek to connect within 36 months

(b) if the investor is a distributor and chooses to pass the costs onto load customers[17]

(c) if the investor is a distributed generator and can increase the size of their generating plant at a lower average cost.

2.25. If new DG connects to an investment paid for by a load customer, there is no basis for cost-sharing even if the DG connects within 36 months. This means charges to distributed generators cannot be used to reimburse the costs load customers incurred as first movers.

2.26. Future distributed generators and load customers are potentially disadvantaged by the current incremental cost limit as they may end up paying more to connect because lower-cost capacity was not built in advance.

2.27. The reason they are disadvantaged is because distributors may only charge incremental costs that are defined to be the ‘reasonable additional costs’ – which include any reasonable additional transmission costs – that an efficient distributor would incur in providing electricity distribution services to DG. These costs don’t include the distribution costs that an efficient distributor would be able to avoid as a result of the electrical connection of the DG.[18]

2.28. It is unclear whether reasonable additional costs would include distributors building extra capacity for future connections. This would mean distributors may be deterred from building capacity in advance if it cannot charge future DG for it.

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16 Notably, investors in DG have choices over which projects – on which distribution networks – they choose to invest in. This means there is limited capacity to charge inefficiently high prices.

17 This choice is not costless and for non-exempt distributors is disincentivised by price-quality regulation.

18 Clause 1.1(1) of the Code, definition of incremental cost.

The one-size-fits-all cost-sharing formula may discourage efficiency

2.29. Even when new distributed generators seek to connect within 36 months, the DGPPs prescribe cost-sharing based on shares of maximum generation.[19] This one-size-fits-all prescription may not suit all circumstances.

2.30. For example, capacity could be shared by two distributed generators of similar size with one injecting most of the time and another injecting when the other isn't. That would be an efficient use of capacity, but this arrangement could be discouraged by cost-sharing based on maximum generation.[20]

The incremental cost limit yields weak incentives to dedicate resources to DG

2.31. An increase in generation on distribution networks may add new demands on distributors' resources, other than capital expenditure. For example:

(a) people and processes to assess applications and options for connecting generation.

(b) new network monitoring and control systems.

2.32. Some of these costs can be recovered from distributed generators on an incremental cost basis because they relate to a particular project or plant, for example by recording time spent on processing or monitoring a particular project.

2.33. Some costs cannot be attributed to a particular generation project. This includes costs of network monitoring and control systems, time and money spent recruiting and training staff and developing strategies and processes to make best use of existing network – including developing pricing methodologies.

2.34. The incremental cost limit means costs not attributable to a particular distributed generator cannot be recovered from that one, even if those costs are attributable to DG in general, as a class of customer.

The incremental cost limit creates other impediments to efficient pricing

2.35. A strict incremental cost pricing rule may be inconsistent with efficient distribution pricing in two further respects:

(a) It precludes the option to broaden the general revenue base to include distributed generators.

(b) It makes cost-reflective pricing more difficult than it needs to be as distributors will be discouraged from using approximations, even when it is reasonable to do so.

2.36. It is unlikely there would be large gains from broadening the revenue base to include generators, however such gains cannot be discounted entirely. A broader revenue base could, for example, reduce charges faced by commercial customers considering

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19 Schedule 6.4 of the Code, principles 2(i)(i) and (ii).

20 If it suits both parties, an arrangement could be made, in principle, for cost-sharing on a basis other than maximum output shares. However, that would come with transaction costs that could be reduced if the distributor, as an intermediary, could make a judgement about reasonable cost sharing arrangements.

electrifying their energy supply. Given those customers are likely to be more price sensitive than most, a reduction in their charges could be a material consideration in constructing prices that least distort network use.[21]

2.37. Cost-reflective tariffs, such as critical peak tariffs, are only approximations to costs and are set in advance. Ideally, they would be dynamic, reflecting actual network conditions and costs. But this is currently impractical for most purposes – there is a trade-off between accuracy and simplicity.

2.38. Without the ability to set dynamic cost-reflective prices, pre-set administratively determined peak charges may be efficient – relative to not having any such charge.

2.39. The same can be true for peak charges on distributed generators in cases where these distributed generators are creating costs, for example by causing voltage instability. However, the use of such pricing could raise questions over consistency with the incremental cost pricing rule because the costs being reflected would be approximations of costs and not actual costs incurred.

Q2. Do you agree with the problems with the incremental cost limit identified in this section? Why or why not? Do you have a view on the relative importance of the problems identified?

Q3. Do you agree circumstances have changed significantly since the DGPPs were introduced, including that there are now far fewer impediments to DG than in the early 2000s?

Q4. Do you agree with the assessment of the current situation and implications of incremental cost pricing? If not, why not? What if any other significant factors should the Authority be considering?

[21] This example assumes there may be situations where sunk costs need to be recovered from an area without a large and comparatively price insensitive commercial and residential customer base.

3. We have identified options to address this issue

3.1. In this section we consider the following four options for addressing the issue identified in section 2:

(a) retain the existing DGPPs

(b) modify the DGPPs to address the identified issues

(c) remove the DGPPs and rely entirely on contracting

(d) comprehensive overhaul of the DGPPs (our current preferred option).

3.2. We invite stakeholders to share their perspectives on which of the four options will best promote the long-term benefit of consumers.

3.3. However, in this section we also set out our current, tentative view that there is a good case to overhaul the DGPPs comprehensively augmented by specific guidance for injection prices. Under this approach, the Authority would monitor distributors' progress towards more efficient pricing for DG, with a view to adopting a more prescriptive approach if we do not see rapid progress. We expect this approach would encourage distributors to move towards efficient price signals for DG over time and lead to reliable, secure supply that meets demand at lowest cost to consumers.

Option 1: Retain the existing DGPPs

Description of option

3.4. The first option is the status quo position: retaining the existing DGPPs in Schedule 6.4 of the Code and making no amendments.

Discussion

3.5. The status quo is not the Authority's preferred option, because the issue raised in section 2 appears significant and in our view needs to be addressed. As discussed earlier, the DGPPs may be preventing distributors from efficiently planning for future connections. Left unaddressed, these problems could negatively impact on security of supply and lead to higher charges for consumers.

Option 2: Limited modification of DGPPs to address the identified issues

Description of option

3.6. Under this option, the DGPPs would be retained in Schedule 6.4 of the Code, however, targeted amendments would be made, intended to address the issues with the incremental cost limit identified in section 2. At this stage we have not developed a comprehensive Code amendment package that would address all the issues identified. However, targeted amendments could include:

(a) an amendment to clarify the definition of incremental cost (for example, to clarify the treatment of consequential costs related to frequency or voltage) and/or

(b) adding a clause creating an exception to the incremental cost limit to allow for allocation of attributable costs to DG as a customer class, and/or

(c) deleting principle 2(m) to remove the time limit on recovery and refunding of connection costs by, and/or

(d) replacing the prescriptions for cost-sharing in principles 2(i)(i) and 2(i)(ii) with 'prices should account for differences in network services provided and be responsive to end users' circumstances and requirements' to allow discretion in how costs are recovered.

Discussion

3.7. The targeted Code amendments we have in mind under this option may be capable of addressing some of the issues with the incremental cost limit covered in section 2. For example, allowing for allocation of attributable costs to DG as a customer class could help to address the first mover disadvantage issue.

3.8. Further, retaining the DGPPs in an amended form might address an imbalance of bargaining power between distributors and distributed generators – which was a key concern when the DGPPs were first introduced. The DGPPs were intended to ensure that DG does not face undue barriers in connecting to lines and ensure a level playing field for investment in DG and in grid-connected generation. To the extent that an imbalance of bargaining power still exists, this would suggest that the DGPPs may still play a necessary role.

3.9. In December 2016, the Authority chose not to remove the DGPPs from the Code because it was aware of the risk that the proposal would have let distributors use monopoly power to overcharge owners of DG for connection services. The Authority considered at the time that this proposal might not promote competition as it might inefficiently tilt the playing field against DG, in favour of grid-connected generators.[22]

3.10. Since the introduction of the DGPPs, the installation of DG has increased markedly. This could be taken as evidence that the DGPPs have helped to eliminate barriers to investment in DG. (However, it might also be due to inefficient subsidies or to the reduction in the costs of some types of DG.)

3.11. Some other key advantages of this option are that, as it is a more limited change (compared with removing the DGPPs completely), it may involve lower costs to implement and may also have less scope for unintended consequences.

3.12. However, targeted Code amendments may be less effective than removing the DGPPs in addressing all of problems identified. For example, the amendments noted above would not appear to address the risk of incentivising excessive investment in DG (noted in section 2), which would raise consumers' costs of electricity supply. The DGPPs, even as amended, would still be highly prescriptive and challenging for distributors to implement accurately. So the risk of setting prices that do not reflect local network conditions would remain, leading to problems of DG being over- or

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22 Electricity Authority, Review of distributed generation pricing principles: Decision and reasons, 6 December 2016, p 9.

under-incentivised. This option could still lead to excessive costs for consumers and security of supply problems.

3.13. Taking a step back, it is possible that the advantages of retaining the DGPPs in some form are fewer than they used to be. Circumstances are different now compared to when the DGPPs were first introduced. This suggests that the underlying reasons for having separate pricing principles for DG may no longer apply.

3.14. The DGPPs were introduced at a time when the rate of connection of DG was much lower compared to today and the opportunities were location- and resource-specific. The purpose behind the principles envisaged a future with much greater penetration of DG and the policy intent was to safeguard this change.

3.15. Now, with the improved cost-effectiveness of technologies like solar and battery storage, DG is much more modular, less connected to location-specific resources and more cost-competitive with grid-connected generation. Accordingly, the issue may no longer be how to remove impediments to a change occurring, but how best to manage the impacts of a change that has begun and gathered momentum.

3.16. Distributors are facing a substantial increase in generation on their networks that requires decisions about how to allocate potentially scarce resources and recover costs. Regulatory measures that make it harder to allocate resources to host increased amounts of DG risk impeding efficient investment by distributors and distributed generators.[23]

3.17. Concept Consulting's 2023 survey of generation investment activity[24] reported on difficulties some distributors face managing new investment in DG:

> *(…)* The surge has driven sharp learning curves and resourcing constraints for impacted distributors, contributing to extended lead times. Engineering and commercial processes are more complex and iterative than smaller-scale DG and introduce technical challenges that are unique to utility-scale generation.

3.18. This suggests circumstances have changed significantly since the DGPPs were introduced in 2007. Learning and resource constraints may now be bigger impediments to investment in DG than asymmetries in bargaining power.

Option 3: Remove DGPPs and rely entirely on contracting

Description of option

3.19. This option involves the Authority removing the DGPPs from the Code entirely – and not replacing them with any alternative Code or principles. Under this option, we would rely on parties' commercial incentives to achieve our objectives. This would involve greater reliance on distributors contracting with DG directly or via aggregators or virtual power plans, as discussed in Appendix C (eg, Aurora

23 The Authority is addressing some of these issues through its Network Connection Project.

24 Generation investment survey, 2023

Energy's contract with SolarZero). Over time, new aggregators and business models may emerge which would help to address the issues we have identified.

Discussion

3.20. There are some arguments in favour of this approach. First, when contracting directly, distributors have an incentive under the Commerce Commission regime to fund injection out of operating expenditure, as they can retain savings on capital expenditure and share these with consumers. Further, the Commerce Commission's new Innovation and Non-Traditional Solutions Allowance (INTSA) might promote more such activity than has occurred in the past.

3.21. Second, this contractual approach helps uncover the efficient price, because:

(a) Competition among retailers[25] and aggregators for consumers with small-scale DG will drive the discovery of efficient injection prices for consumers.

(b) Distributors can run competitive procurement processes to get the best deal for non-network alternatives as those with a pool of small-scale DG compete with each other and other potential providers.

(c) Wholesale market prices provide a reference point for efficient prices. Further price signals (over above wholesale price signals) are only efficient if they reflect marginal costs of capacity or losses on distribution networks.

3.22. However, the Authority is not currently convinced that we can rely on contracting alone to solve the identified problems. Distributors are not required to contract with (or even to consider contracting with) DG as a non-network solution. The available evidence is that only a small number of distributors are engaging with DG in this way. The aggregator or virtual power plant model also appears to be under-utilised compared to the scale of problem.

3.23. The under-utilisation might be because distributors may have a preference towards investing in poles and wires instead of seeking non-network solutions. Institutional drivers may cause network owners to prefer asset and ownership solutions over procuring network alternative services from third parties.[26]

3.24. If distributors adopt non-network alternatives, they do not relinquish responsibility and accountability for meeting regulatory and quality standards. As such, distributors will put a high value on reassurance that a non-network solution provided by a third party will be available when needed, so they can continue to meet regulatory and quality standards. This suggests networks may prefer to 'make' or 'own' the solution, in situations where there is a need to control performance, and it is difficult to anticipate the need for the service or to observe performance.

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25 Retailers offer electricity buy-back rates that are currently fixed between 8 and 17 cents per kWh, with Octopus Energy offering a higher peak rate (40 cents per kWh) and lower off-peak rates and Flick Electric has a buy-back rate that varies with the wholesale rate. See Solar buy-back rates — Powerswitch NZ .

26 These drivers are legitimate considerations in any business case for non-network solutions, as they reflect regulatory quality requirements or consumer preferences.

3.25. We note that in its recent review of this matter, the Commerce Commission considered investment in capital expenditure like poles and wires rather than non-network solutions.[27] The Commerce Commission considered that current regulatory settings appropriately incentivised non-network solutions.

Option 4: Comprehensive overhaul of DG pricing principles

Description of option

3.26. The Authority's current preferred option is for an overhaul of the pricing principles applying to DG. This revision would be more comprehensive than the limited modification of the DGPPs that would occur under Option 2. Under Option 4, the Authority would develop pricing guidance for distributors through a new set of pricing principles applicable to DG. The new principles could potentially draw on the pricing guidance for load customers that the Authority has already produced.[28]

3.27. The new principles could either be included within the Code or outside of it, as per the 2019 DGPPs. Under this option the Authority would consult at a later date on the content of any revised pricing principles for DG and on whether or not the principles should be included in the Code.

3.28. We envisage that this option would be relatively flexible. At least initially, the new principles would be less prescriptive than the existing DGPPs: the new principles would not restrict pricing to incremental cost. Distributors would be able to develop their own approach to pricing for DG, guided by the new principles. As with distribution pricing for load customers, the Authority would be able to observe the sector's responses and change its approach if necessary (for example, intervening to increase the level of prescription via a more prescriptive Code amendment at a later date). For instance, the Authority is currently presenting codified pricing principles as a preferred option applicable to standard (mass market) consumers with DG that export energy to the network, as discussed in the Consultation Paper "Requiring distributors to pay a rebate when consumers supply electricity at peak times".

Connection pricing for DG

3.29. Depending on the Authority's decision regarding its proposal released in November on connection pricing for load customers, the recommended approach for load customers could also be applicable to connection pricing for DG.

3.30. The distribution connection pricing consultation paper[29] proposes to introduce a package of fast-track measures to improve consistency, transparency and cost-

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[27] Commerce Commission (2023) 'Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final Decision', 13 December 2023, p.227.

[28] The Authority's approach to distribution pricing includes the distribution pricing principles, guidance, and the distribution pricing scorecards. Distribution pricing | Electricity Authority

[29] Electricity Authority. Distribution connection pricing proposed Code amendment, October 2025, Consultation paper

reflectivity for load seeking a new or enlarged connection. The fast-track measures proposed include five pricing methodologies, dispute resolution provisions, and an exemption process to facilitate price-quality path reviews. The consultation paper also provides an overview of the Authority's direction of travel for full reform. For full reform, our preference is to prescribe a formula-based approach to recognise the impact of new connections on the network (both incremental costs and revenues) and ensure connecting parties contribute towards shared network costs. This would provide cost-reflective pricing for connection applicants while ensuring the benefits of connection growth are shared between newcomers and existing users.

3.31. The Authority has not yet considered in any detail whether the current proposed approach to connection pricing for load customers should also be applicable to connection pricing for DG. It is noted here as a possible option to consider in the future.

Discussion

3.32. Option 4 may be less prescriptive than some of the other options: it allows distributors flexibility to apply the principles to their own particular network circumstances.

3.33. Under this principles-based approach we would envisage providing guidance that can be applied to local situations by distributors. For example, the problems of networks with irrigation load, which peaks in summer, will be different from the majority of networks, which peak in winter. The Authority has issued targeted guidance on distribution pricing for consumers over the last few years. These processes have been relatively successful in achieving pricing reform, and we have observed that most distributors comply with the issued guidance.

3.34. This option would require the Authority to issue specific guidance on the treatment of DG. Such guidance could either be codified or exist outside the Code, which is the case with the 2019 DGPPs..

3.35. The Authority’s existing DGPPs for load are of broad application and would appear to be well suited to application to DG. For example, the principle that distribution prices should reflect the impacts of network use on economic costs will promote efficient investment and use of DG. Similarly, the principles that distribution prices should reflect differences in network service provided *by consumers* and encourage efficient network alternatives are clearly applicable to DG.

3.36. Option 4 would solve many of the problems with the Part 6 incremental cost limit, as described in section 2. It would allow distributors to allocate costs to distributed generators beyond incremental costs. For example, the existing DGPPs for load state that where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use. This option would also allow distributors to appropriately handle first-mover disadvantage and spread the cost of shared DG assets between distributed generators in a way that appropriately reflects the cost the DG imposes on the network.

3.37. This option would allow distributors flexibility in how they approach signalling costs to DG (including the rate) and sharing common costs with DG. These matters are not straightforward, and the best approach may vary depending on the circumstances. Allowing flexibility for distributors to act, consistent with principles and guidance (as opposed to mandating particular actions in Code), will allow distributors to respond most effectively to the circumstances and adapt their approach over time, as more information (including more granular data on network cost) becomes available.

3.38. In the case where the principles sit outside the Code, there is a risk that distributors might choose not to comply with voluntary principles and guidance (and could fail to offer cost-reflective rebates to DG). However, the Authority will be monitoring outcomes, and always has the option of moving to a more prescriptive approach if it does not observe sufficient progress towards efficient pricing for DG.

3.39. On the other hand, if the pricing principles are mandated as a Code requirement, the Authority can enforce compliance while giving some degree of flexibility to distributors to apply them, which would result in a stronger and more urgent response from distributors. This approach is currently being proposed in relation to standard consumers with DG that export energy to the network as discussed in the Consultation Paper "Requiring distributors to pay a rebate when consumers supply electricity at peak times". In this case, the existing DGPPs would be removed from the Code and replaced with a new set of Codified pricing principles.

3.40. We have considered the risk that removing the DGPPs could result in reduced payments to DG that are important for reliability, and so potentially alter the availability of such DG, which could in turn present a risk to reliability. The existing DGPPs require distributors to make payments to DG for avoided cost of distribution (ACOD), so removing the DGPPs might result in fewer such payments. This risk appears to be low, given the following factors:

(a) Based on the available information, there appear to be only two distributors making ACOD payments to distributed generators: Top Energy and Eastland (First Light). Both of these distributors are (or were) making payments to related parties (generation owned by the distributor or by a related business).

(b) Existing DG to cease operation if ACOD payments cease, given ongoing revenue streams linked to nodal prices.

3.41. In any case, the Authority has not yet determined the content of any revised pricing principles for DG. A revised set of pricing principles might continue to encourage or require distributors to make payments for ACOD – depending on whether the Authority determined such a rule to be efficient.

Q5. Do you agree these are the appropriate options to consider?

Q6. Are there other options the Authority should consider for improving rules about costs that can be recovered from distributed generators?

Q7. Will new aggregator business models emerge to solve the problem?

Q8. Are distribution price signals alternative to, or complementary to, contracting?

Q9. Which, if any of the above options, do you consider would best support efficient pricing for recovery of distribution costs from DG?

Q10. Do you agree with the Authority's tentative view on a solution? In particular:

- Should efficient price signals be sent through a revised set of pricing principles?
- Would voluntary guidelines or mandating through the Code be the best approach?
- Should we rely on the distribution pricing principles outside the Code or codified new pricing principles for DG? Why?

Q11. Are there any unintended consequences from removing the existing DGPPs?

- Do you agree with the risks we have identified, and our assessment of them?
- Do you think there are any other risks we should consider associated with the removal of the DGPPs?
- Do you have any information that would allow the Authority to better assess such risks?

4. DG price signals are appropriate with respect to transmission costs

4.1. While this paper is focused in the DGPPs, as part of our consideration of the price signals to DG we also considered transmission cost signals.

4.2. In 2022, the Authority decided to remove certain Code provisions that required distributors to make payments for avoided cost of transmission (ACOT) to certain DG.[30] As part of this decision, the Authority committed to review whether the removal would reveal gaps in incentives for efficient investment in, and operation of, DG.

4.3. The Authority has carried out the first stage of that review. In doing so, we considered wholesale market incentives, as well as incentives and requirements on Transpower to consider and provide transmission alternatives. To illustrate existing incentives for DG, we examined case studies of three distributed generators that illustrate how the income from generation provides incentives to operate.[31]

4.4. Our main finding is the wholesale market dispatch and price discovery mechanism results in efficient rewards for DG's contributions to avoiding transmission costs, supporting grid reliability and delaying or avoiding transmission investment. The Authority has not identified market or regulatory gaps with respect to transmission costs that it considers would adversely affect incentives for the efficient investment in, and operation of DG. The reasons for these findings are outlined in more detail in this section of the paper and in case studies presented in Appendix D.

4.5. We invite feedback on this assessment and its implications.

Wholesale market prices provide efficient incentives for DG

4.6. The operation of the wholesale electricity market affects incentives for investment in, and operation of DG.

4.7. The wholesale market balances electricity supply and demand at least cost to consumers. The cheapest generation offered is dispatched ahead of more expensive generation to meet demand. This continues until the price that generation is offered at exceeds the price consumers are willing to pay.

4.8. This process happens for each trading period at each of 280 locations (nodes) around the country. In a competitive electricity market, this balancing process discovers the efficient price at each node. Nodal prices reflect local demand and supply conditions, as well as national grid or local network capacity and constraints.

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30 These requirements had only applied to certain named pre-2017 generators. [Avoided cost of transmission payments | Our projects | Electricity Authority]

31 The case studies of wholesale market effects on the operation of three distributed generators are set out at Appendix D.

4.9. Nodal prices reflect the incremental cost and value to consumers of changing electricity consumption at each location. This means they provide efficient locational investment and operating signals to both grid-connected and DG.

4.10. DG can offer to provide ancillary services to support the reliable operation of the power system. These services are bought either through fixed price-quantity contracts via a competitive procurement process, or through a half-hour market clearing process described above, which results in the least-cost allocation of resources to either ancillary services or generation.

4.11. Submissions to the Authority's 2022 consultation paper[32]on removing ACOT payments raised perceived issues with the effectiveness or sufficiency of nodal prices as an incentive for DG, which ACOT payments were expected to have addressed. [33]

4.12. The Authority re-considered these claims within the context of the present paper but has not identified deficiencies in market or regulatory settings. For example:

(a) Nodal prices do not "collapse" as soon as local generation comes on stream.

(b) Nodal prices may reduce if DG offers more supply or when there is new investment. But this is not the same as an incentive-destroying price collapse. It would only be rational for a generator to offer to supply if it expects prices to at least cover their incremental cost.

(c) Nodal prices can be volatile, but they do provide an efficient signal.[34] There are clear daily, weekly and seasonal patterns in demand around which DG can offer or schedule their outages. There is a positive correlation between demand and spot prices (see Figure 1 over page), meaning there is both information and an incentive to make DG available during periods of high demand with higher expected nodal prices.

(d) This is also likely to be the case when DG supplies under contract. Purchasers will likely want certainty of access to contracted generation at agreed prices, particularly when generation is scarce and prices high.

4.13. The Authority has not identified any indications that incentives or requirements on DG with respect to wholesale market participation, (including providing ancillary services), may be deficient or biased compared to grid-connected generation.[35] The Authority is interested in the sector's views on this conclusion, and in evidence that may indicate any issues.

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[32] Code change to remove avoided cost of transmission payments | Our consultations | Our projects | Electricity Authority

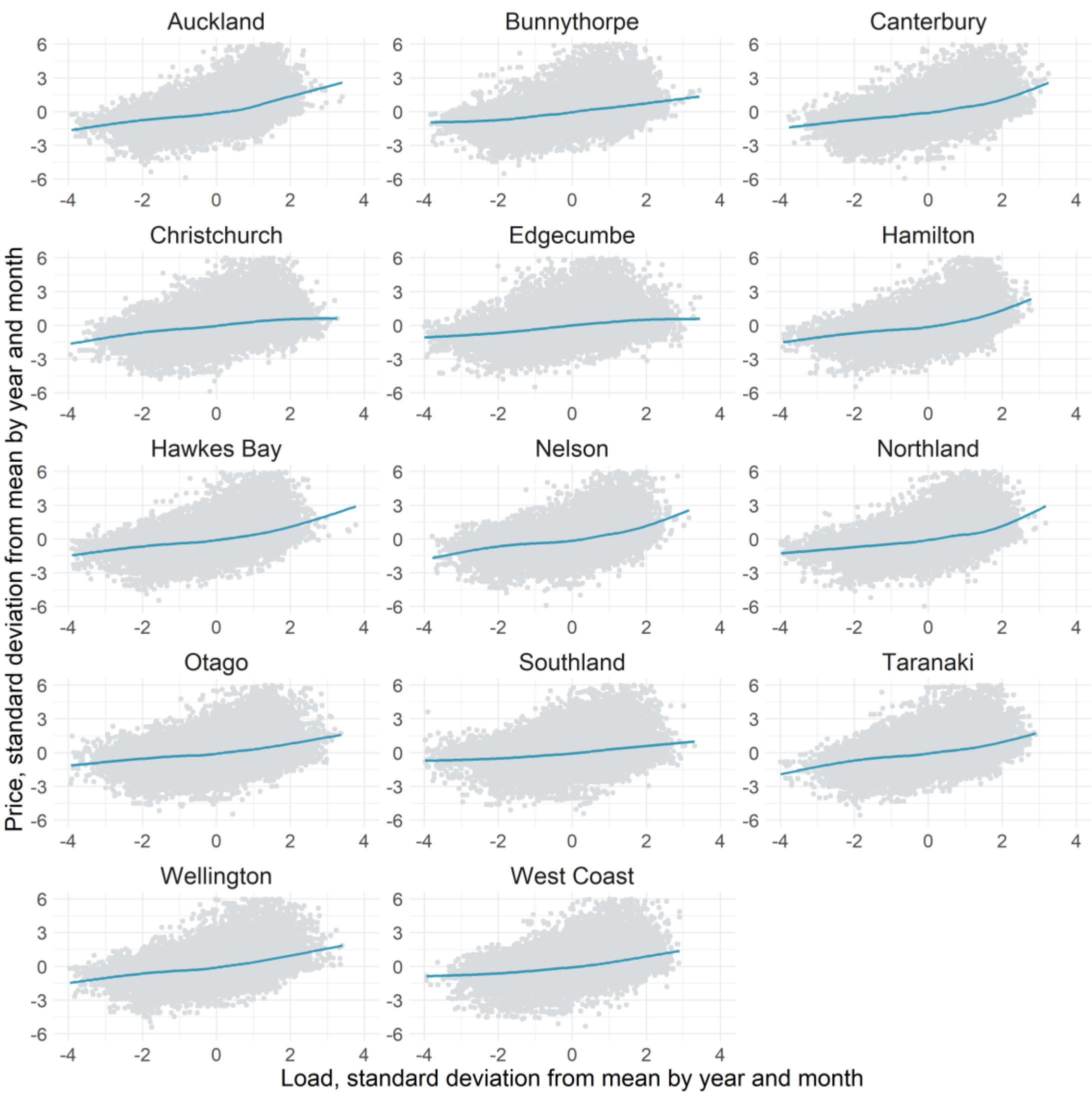
[33] For example, submissions from Vector (Vector-submission-consultation-on-ACOT-payments-to-DG.pdf) and Manawa Energy (Manawa-Energy-Submission-on-ACOT-Code-change-FINAL.pdf).

[34] Some participants considered that ACOT payments were important to overcome nodal prices being too unpredictable to ensure DG would supply (and avoid scheduling outages) at peak times.

[35] As noted above, the real-time pricing project advanced lower-cost ways for smaller-scale DG and flexible demand to participate in the dispatch process, and other work is underway to remove non-price barriers.

Figure 1 Positive relationship between demand and wholesale prices 2014–2020

Prices and load by trading period and system operation zone. Deviations around monthly average prices. Axes truncated.



DG is recognised for its role in lowering transport costs and grid investment

4.14. Some submissions to the Authority's 2022 consultation paper considered that removing ACOT payments would mean DG contribution to deferring or avoiding transmission cost is no longer being recognised.[36] As a consequence, these submissions considered removing ACOT payments would lead to underinvestment

36 For example, submissions from King Country Energy: (KCE-submission-on-ACOT-Final.pdf), Ngawha (20220120-Ngawha-Submission-on-ACOT.pdf) and Manawa Energy (Manawa-Energy-Submission-on-ACOT-Code-change-FINAL.pdf)

in and underutilisation of DG, and higher grid transport costs and investment in transmission infrastructure.

4.15. DG may lower transport cost and demand for grid assets, but there is some uncertainty around this.

4.16. The Authority agrees that when DG supplies local consumers, this can lower grid transport costs by reducing energy losses and grid congestion. But DG that exports electricity to the network and wider grid will use transmission assets. DG then contributes to grid transport costs and demand for grid assets. And if DG is intermittent, it may not affect the transmission capacity needed to meet grid service levels.

4.17. Nodal prices already capture grid transport costs – the losses of electricity that occur when it is transmitted across the country. DG dispatched to supply local consumers is paid this nodal price[37] yet does not incur grid transport costs. This gives DG a cost advantage over grid-supplied generation at the relevant node. It does not suggest the need for any further incentive for efficiency reasons.

4.18. Nodal prices also reward DG for providing an alternative to transmission investment. When demand for grid-supplied electricity is higher than transmission capacity at the node, causing congestion on the grid, nodal prices will rise to balance demand and supply.

4.19. This means DG may be dispatched at these higher prices when there is a grid constraint. That is, DG operating downstream of the constraint is being rewarded with a higher market price for being an alternative to transmission capacity.

4.20. This situation will persist until the expected frequency and duration of the higher nodal prices (due to congestion) attracts investment in more DG or justifies investment in more transmission capacity, for the long-term benefit of consumers.

4.21. Based on this assessment, the Authority does not currently consider there is an efficiency reason for any further incentive for DG's role in delaying or avoiding transmission investment. However, the Authority is interested in submissions with evidence of any gaps or issues on this point.

DG receives appropriate compensation for supporting grid reliability

4.22. DG can reduce the amount of local demand that must be supplied through the grid. This means it may reduce the grid capacity required for Transpower to meet N-1 reliability for the core grid or an economic level of reliability across the grid.[38]

4.23. Some submissions in 2022 considered that removing ACOT payments would mean DG is no longer fully compensated for contributing to grid reliability and security and

[37] Where DG is not directly exposed to spot prices, it is reasonable to assume contract prices reflect expectations of spot prices.

[38] See clause 2 of Schedule 12.2 of the Code. The core grid is defined in Schedule 12.3 of the Code.

is avoiding the cost of transmission investment that would otherwise be required to meet N-1 or economic level of reliability.[39]

4.24. This view implies that without some extra payment, DG would no longer supply to support grid reliability, meaning grid investment must be brought forward, with costs flowing through to consumers.

4.25. Investment in and operation of DG is primarily driven by expectations of profit from generating electricity (or other private purposes). Any contribution to grid reliability, therefore, is usually a secondary purpose or a co-incidence.

4.26. Even so, when Transpower considers reliability or economic transmission investments, it takes DG into account if it reliably offsets a GXP's peak demand. However, if the relevant DG supply is not controllable or reliable, then Transpower assumes it is not available at peak in its N-1 reliability assessments and investment cases.

4.27. Where grid assets are not core assets, the level of security is a matter for distributors, as transmission customers, in consultation with Transpower.

4.28. Therefore, DG's presence does contribute to grid reliability and supply security. In practice, this contribution is usually recognised by wholesale market revenues. DG would earn higher spot prices when:

(a) grid security constraints apply – these transmission constraints are reflected in the Scheduling Pricing and Dispatch model or applied manually.

(b) an outage or a fault interrupts grid supply to the area – this may include applying scarcity prices defined in the Code when demand must be constrained to available supply.

4.29. These higher prices, which reflect demand and supply conditions, signal the extent consumers are willing to pay for reliability. Therefore, they provide an efficient reward for DG supporting reliability. To the Authority, this suggests there is no efficiency reason for any further incentives.

4.30. The Authority is aware of an alternative view that argues spot prices would not be able to get high enough to appropriately compensate DG for avoiding transmission costs or supporting reliability.

4.31. The Authority has re-considered these claims within the context of this issues paper, but has not identified deficiencies in incentives that may have been masked by ACOT payments:

(a) One concern is that Transpower builds capacity ahead of constraints being reached, so nodal prices will never get high enough. This concern is not one about the efficiency of electricity prices, but the efficiency of grid and local network investments.

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[39] For example, see report by Calderwood Advisory in Appendix 1 to the submission by Manawa Energy (Manawa-Energy-Submission-on-ACOT-code-change--Appendix-1.pdf)

(b) These investments are subject to a clear regulatory framework, including the Grid Reliability Standard, Investment Test, and controls on allowable revenues for Transpower and price-quality regulation of distributors. This means investments should only go ahead if they are required and are the best option to meet regulatory requirements (core grid reliability), or pass an economic test, and fit regulated revenue.

(c) If grid or local network investments run ahead of constraints so high prices are rare, then in principle this is a positive long-term outcome for consumers.

4.32. While this is a possible outcome, Transpower's regular publications on the adequacy of the transmission network and investment opportunities and timelines indicate this is rare.[40]

4.33. Another potential issue raised is that the trading conduct rules restrict DG from pricing at levels that reflect economic costs, including opportunity costs at times of constraints.

4.34. The concern is this undermines incentives for generators to make energy available when it may be needed most. However, the Code does not restrict DG offering in a way that reflects their operating costs, including opportunity cost. And offering generation at zero does not mean nodal prices would be zero. Case studies in Appendix D present further analysis.

Transpower can contract DG as a transmission alternative

4.35. Transpower can also choose to use Grid Support Contracts to contract with DG to provide reliability services rather than investing in transmission assets.

4.36. Such contracts should entice additional investment in, or operation of DG capacity to be available as a contingency or defer investment in transmission, that would otherwise not be provided.

4.37. The contracts would need to avoid paying for generation that would or could provide profitably in response to wholesale market prices. The contracts would need to pay only what is necessary to secure the additional services, for example, through a competitive procurement process. Setting a price based on avoided costs or value of lost load will not result in a least-cost solution for consumers.[41]

4.38. Transpower's 2016 publication on Grid Support Contracts[42] sets out appropriate design features that address these types of considerations. Transmission alternatives would likely be smaller-scale projects that can be dispatched on demand to manage peaks, and for relatively small capital costs. Technologies that

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[40] See Transpower's Transmission Planning Reports at Transmission Planning | Transpower, and case studies in **Error! Reference source not found.**D.

[41] A key challenge is it is very difficult for a network owner or system operator to know if a side payment via a Grid Support Contract is necessary and will save consumers money. This problem is most acute for larger-scale capital-intensive generation because there is a greater risk of a side payment resulting in displacement of investment in other lower-cost generation longer term.

[42] See Transpower 2016, Grid Support Contracts GSC design features, at Grid Support Contracts

are currently suitable include grid-scale batteries and peaking thermal generation or demand response.

Q12. Do you agree market and regulatory settings provide efficient incentives for DG reducing or avoiding transmission costs? What, if any, other significant factors or options should the Authority consider?

Appendix A Format for submissions

Submitter	

Questions	Comments
Q1.Do you have a view on the definition of incremental cost that is contained in the Code? Should it be more tightly defined to include only network costs and to exclude consequential costs relating to factors such as frequency keeping and voltage support? Would this lead to more timely generation build and lower energy costs?	
Q2. Do you agree with the problems with the incremental cost limit identified in this section? Why or why not? Do you have a view on the relative importance of the problems identified?	
Q3 Do you agree circumstances have changed significantly since the DGPPs were introduced, including that there are now far fewer impediments to distributed generation than in the early 2000s?	
Q4 Do you agree with the assessment of the current situation and implications of incremental cost pricing? If not, why not? What if any other significant factors should the Authority be considering?	
Q5. Do you agree these are the appropriate options to consider?	
Q6. Are there other options the Authority should consider for improving rules about costs that can be recovered from distributed generators?	
Q7. Will new aggregator business models emerge to solve the problem?	

Q8. Are distribution price signals alternative to, or complementary to contracting?	
Q9. Which, if any of the above options, do you consider would best support efficient pricing for recovery of distribution costs from DG?	
Q10. Do you agree with the Authority's tentative view on a solution? In particular: • Should efficient price signals be sent through a revised set of pricing principles? • Would voluntary guidelines or mandating through the Code be the best approach? • Should we rely on the distribution pricing principles outside the Code or codified new pricing principles for DG? Why?	
Q11. Are there any unintended consequences from removing the existing DGPPs? • Do you agree with the risks we have identified, and our assessment of them? • Do you think there are any other risks we should consider associated with the removal of the DGPPs? • Do you have any information that would allow the Authority to better assess such risks?	
Q12. Do you agree market and regulatory settings provide efficient incentives for DG reducing or avoiding transmission costs? What, if any, other significant factors or options should the Authority consider?	

Appendix B Distributed generation pricing principles

Schedule 6.4: the DGPPs

B.1. Clause 2 of Schedule 6.4 of Part 6 of the Code sets out the pricing principles for Distributed Generation.

The pricing principles are as follows:

[…] Charges to be based on recovery of reasonable costs incurred by distributor as a result of connecting the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs.

(a) Subject to paragraph (i), connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the **distributed generation:**

(b) When calculating **incremental costs**, any costs that cannot be calculated must be estimated with reference to reasonable estimates of how the **distributor's capital** investment decisions and operating costs would differ, in the future, with and without the generation:

(c) Estimated costs may be adjusted ex post. Ex-post adjustment involves calculating, at the end of a period, the actual costs incurred by the **distributor** as a result of the **distributed generation** being **electrically connected** to the **distribution network**, and deducting the costs that would have been incurred had the generation not been **electrically connected**. In this case, if the costs differ from the charges to the **distributed generator**, the **distributor** must advise the distributed generator and recover or refund those costs after they are incurred (unless the **distributor** and the **distributed generator** agree otherwise):

Capital and operating expenses

(d) If costs include distinct capital expenditure, such as costs for a significant **asset** replacement or upgrade, the connection charge attributable to the **distributed generator's** actions or proposals is payable by the **distributed generator** before the **distributor** has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the **distributor** is not obliged to incur those costs until that payment has been received:

(e) If **incremental costs** are negative, the **distributed generator** is deemed to be providing network support services to the **distributor**, and may invoice the **distributor** for this service and, in that case, the **distributed generator** must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax):

(f) If costs relate to ongoing or periodic operating expenses, such as costs for routine **maintenance**, the connection charge attributable to the **distributed generator's** actions or proposals may take the form of a periodic charge:

(g) [Revoked]

(h) After the connection of the **distributed generation**, the **distributor** may review the connection charges payable by a **distributed generator** not more than once in any 12-month period. Following a review, the **distributor** must advise the **distributed generator** in writing of any change in the connection charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

Share of generation-driven costs

(i) If multiple **distributed generators** are sharing an investment, the portion of costs payable by any 1 **distributed generator**—

   (i) must be calculated so that the charges paid or payable by each **distributed generator** take into account the relative expected peak of each **distributed generator's** injected generation; and

   (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network:**

(j) in order to facilitate the calculation of equitable connection charges under paragraph (i), the **distributor** must make and retain adequate records of investments for a period of 60 months, provide the rationale for the investment in terms of facilitating **distributed generation**, and indicate the extent to which the associated costs have been or are to be recovered through generation connection charges:

Repayment of previously funded investment

(k) if a **distributed generator** has paid connection charges that include (in part) the cost of an investment that is subsequently shared by other **distributed generators**, the **distributor** must refund to the **distributed generator** all connection charges paid to the **distributor** under paragraph (i) by other **distributed generators** in respect of that investment:

(l) if there are multiple prior **distributed generators**, a refund to each **distributed generator** referred to in paragraph (k) must be provided in accordance with the expected peak of that **distributed generator's** injected generation over a period of time agreed between the **distributed generator** and the distributor. The refund—

   (i) must take into account the relative expected peak of each **distributed generator's** injected generation; and

   (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network:**

(m) no refund of previous payments from the **distributed generator** referred to in paragraph (k) is required after a period of 36 months from the initial connection of that **distributed generator:**

Non-firm connection service

(n) to avoid doubt, nothing in Part 6 of this Code creates any **distribution network capacity** or property rights in any part of the **distribution network** unless these are specifically contracted for. **Distributors** must **maintain** connection and **lines** services to **distributed generators** in accordance with their **connection and operation standards.**

B.2. Clause 1.1(1) of the Code sets out the definition of incremental cost:

incremental costs, for the purpose of Part 6, means:

(a) the reasonable additional costs (which include any reasonable additional transmission costs) that an efficient **distributor** would incur in providing **electricity** distribution services to **distributed generation**; minus

(b) the **distribution** costs (which do not include any transmission costs) that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**.

Appendix C Distributed generation plays a key role

C.1. DG is expanding rapidly and is playing an increasingly important role in the electrification of New Zealand's economy. In this appendix, we discuss the range of DG that exists, the services it provides and the sources of revenue available to owners of DG. There is scope for DG to play a larger role in reducing consumer costs. In the future, DG will also have the potential to increase costs in some areas. DG is already helping to address network capacity problems in some locations, and is being used to delay network investment, saving costs for consumers.

Investment in DG is expanding

C.2. DG is generally defined as any generation connected to a distribution network. It can vary in capacity, fuel type, capital and operating cost, age, operational flexibility, and distance to consumers, and includes batteries.[43] The Code definition specifically excludes any generating plant that is owned or operated by a distributor to maintain or restore electricity supply to part or all the distributor's network.

Table 1: Megawatts (MW) of DG by location and fuel type[44]

	Geo	Hydro	Solar	Thermal	Wind	Other	**Total**	%
Northland	57	5	58	25	0	0	**146**	7%
Auckland	0	1	89	149	3	6	**248**	12%
Waikato	80	99	58	108	64	11	**421**	20%
Bay of Plenty	28	41	59	22	0	4	**154**	7%
Gisborne	0	2	2	1	0	0	**5**	0%
Hawke's Bay	0	9	28	15	0	0	**52**	2%
Taranaki	0	11	15	14	0	6	**47**	2%
Manawatu-Wanganui	0	45	20	14	117	0	**195**	9%
Wellington	0	2	33	17	70	0	**123**	6%
Nelson	0	34	12	4	0	0	**50**	2%
Tasman	0	5	8	0	0	0	**14**	1%
Marlborough	0	3	11	8	2	2	**26**	1%

43 The Authority is proposing, as part of our Network Connections Project, to amend the definition of generating plant in the Code to explicitly refer to energy storage systems (as well as some other equipment that injects electricity into a distribution network)

44 As at 10 January 2025. Source data: https://www.emi.ea.govt.nz/

Canterbury	0	47	112	56	0	25	**240**	11%
West Coast	0	32	1	2	0	0	**35**	2%
Otago	0	46	26	8	8	120	**208**	10%
Southland	0	9	5	5	108	0	**127**	6%
Total	**165**	**391**	**537**	**449**	**371**	**176**	**2089**	100%
Percentage	8%	19%	26%	21%	18%	8%	100%	

C.3. The table above gives a high-level summary of the amount of DG generation capacity (MW) by fuel type and location. DG is concentrated in the North Island and in regions with substantial, but often dispersed, energy resources.

C.4. Approximately 60% of DG capacity basis is for energy cost management (eg, roof-top solar), reliability (back-up supply), or minor revenue streams (eg, landfill biogas) and tend to be smaller in scale and/or owned by industrial consumers. The other 40% is owned by electricity generation businesses for the express purpose of generating and selling electricity. Most DG is intermittent renewables: wind, solar and run-of-river hydro,[45] although increased use of batteries could change this.

C.5. A significant amount of investment in DG is expected to occur as the economy electrifies and technology evolves. The recent Generation Investment Survey notes there has been a "surge in utility-scale solar DG development over the past 12-18 months (and some wind)" and this could "more than double the capacity of utility-scale DG".[46] Although increasing, DG still only makes up about 13% of the pipeline of generation investment activity.

The characteristics of DG vary substantially

C.6. Key features of DG, from a regulatory and system operation perspective, include:

(a) DG is embedded within distribution networks and not directly connected to the grid. This can be an incidental reflection of institutional arrangements (who owns the network asset) rather than material, technical or economic differences in generation.

(b) Some DG is in areas that are experiencing transmission constraints and/or distribution network constraints, while other DG is not.

(c) While some DG operates mainly to supply local communities (reducing demand for network services), other DG exports the electricity it generates (increasing demand for network services).

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45 Run-of-river implies that plant must run when water is available and has limited ability to shift output between time periods. But there is a high degree of variation in controllability within the category ‘run-of-river’. Larger-sized distributed hydro generation that is often classified as run-of-river does in fact have intra-day or intra-week storage, which means output can be altered to meet peak demand.

46 Generation Investment Survey: 2023 Update. January 2024, https://www.ea.govt.nz/documents/4414/Generation_Investment_Survey_-_2023_update.pdf

(d) There is no single causal link between DG and network costs – the presence of DG may:

(i) cause additional costs – for example, connecting a hydro scheme in a remote location to the network or managing voltage stability issues caused by intermittent generation

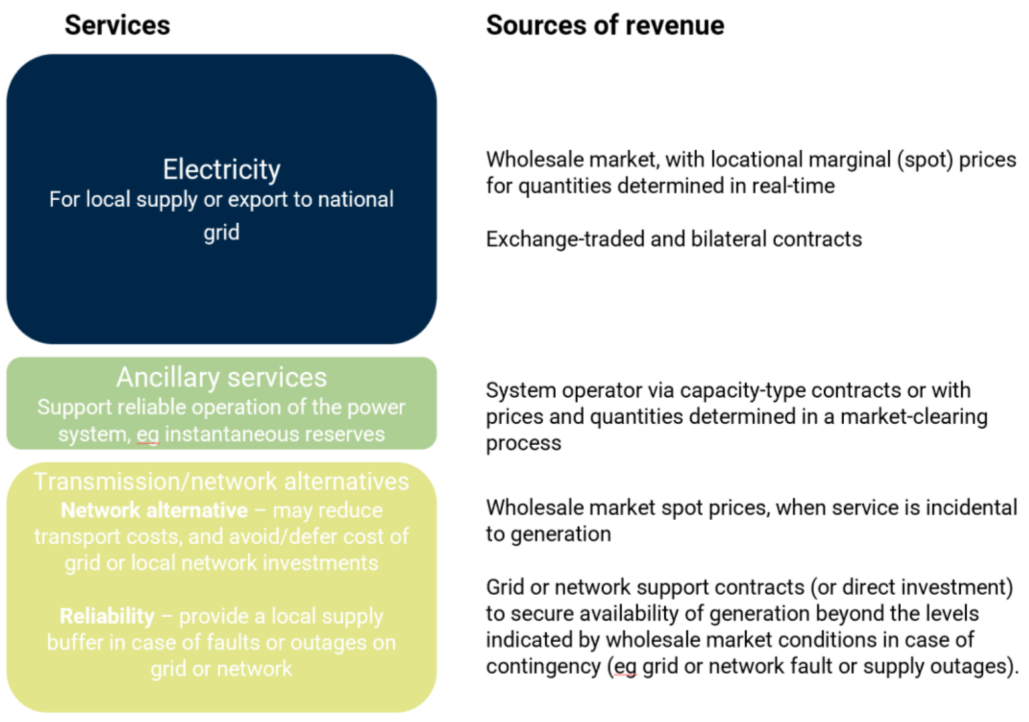
(ii) reduce costs – for example, as an alternative way to supply remote communities, as alternative supply or voltage support in case of a fault or outage on the network, or by reducing peak demand on an otherwise overloaded grid or distribution equipment.

C.7. The large diversity of DG's characteristics requires a system of regulations and incentives to capture these characteristics.

There are various revenue sources for the different services provided by DG

C.8. DG provides a range of services for which the owners may be remunerated through different income sources (**Error! Reference source not found.**C1).

Figure C1 Services provided by DG and sources of revenue



C.9. Large DG operations can access these revenue sources directly as market participants.

C.10. Transaction costs will tend to be too high for small-scale DG to directly access these revenue sources in a commercially viable way. Small-scale DG nevertheless can access these income sources through intermediaries such as retailers and aggregators. This access is increasingly possible with technological and policy innovations.[47]

DG can provide network benefits

C.11. Operating DG can reduce costs for distributors and therefore for other users of distribution networks. For instance, DG reduces the amount of energy that needs to be transported to a particular location via the distribution network – if this occurs at peak times, it can reduce or delay the need for building additional network capacity and so avoid future network costs. DG is already helping to address a range of distribution network issues by:

(e) deferring or avoiding network upgrades – eg, Powerco's solar and battery installations to provide power at peak times in Coromandel,[48]and SolarZero's partnership with Aurora Energy for the Upper Clutha[49] and a pilot scheme for commercial customers (discussed in more detail below)[50]

(a) supplying remote communities – eg., Powerco's 'Base Power' standalone power systems that uses solar, battery and diesel as back-up

(b) supporting reliability – eg, Top Energy's diesel generators in Kaitāia that provide 8MW of back-up supply as the area is supplied by a single line and vulnerable to outages

(c) helping stabilise local voltage – eg, the 7.7MW Amethyst Hydro Power Station on the West Coast that is majority-owned by Westpower.

C.12. However, injecting energy into the grid at peak times doesn't always avoid network costs. This will depend on whether there is a demand-driven capacity constraint (or other problem) on that part of the network and whether the injection would help to relieve it. If there are no such issues, there are no costs to avoid.

C.13. The benefits of DG will therefore depend on its location and the time it is injecting. The value of injection to the distribution network (through avoiding future investment) will tend to be higher when demand at that location is higher and injection from nearby DG is scarce.

Distributors can contract with DG to provide these services

C.14. By contracting with distributed generators, either directly or via aggregators, distributors can send price signals that reflect the value of the DG to the network.

C.15. An example of this is the tailored approach used by Aurora Energy.[51] Since 2020, Aurora Energy has been encouraging non-network alternatives to upgrading its two large (66kV) lines from Cromwell to Wānaka. Aurora Energy has procured support

47 Transpower, Demand Side participation, https://www.transpower.co.nz/system-operator/information-industry/electricity-market-operation/demand-side-participation

48 Powerco. Shoring up Coromandel's power. Shoring up Coromandel's power (powerco.co.nz)

49 In this project, Aurora Energy has paid SolarZero to include larger batteries in their customers installations to reduce peak load and delay a transmission upgrade.

50 ENA. Aurora's Upper Clutha project, https://www.ena.org.nz/resources/publications/document/825),

51 Aurora Energy's approach to injection incentives was also raised by Rewiring Aotearoa in its recent 'Electric Farms' report, https://www.rewiring.nz/electric-farms.

from customers with small-scale solar PV and batteries, via SolarZero,[52] and larger customers have been contracted directly.

C.16. Direct contracting may have the advantage of relatively low transaction costs and enable a distributor to obtain reassurance that the necessary support is available to deliver on regulatory requirements and quality standards.

C.17. Contracting through an intermediary or an aggregator is not new. Retailers and aggregators already buy and sell electricity in the wholesale market on behalf of consumers and small businesses with small-scale DG, and pass on this cost or revenue to these parties, usually in a repackaged way.

C.18. We note that mid-sized customers have been harder to reach, and a pilot scheme has been introduced to reach them. Under the pilot scheme, Aurora Energy offers a discount on peak charges to mid-sized generators for injecting during peak demand periods. The price incentive has initially been set at 50% of the peak charge.

C.19. Aurora Energy's pilot of a peak period discount for hard-to-reach customers provides an opportunity to uncover how cost-effective such price incentives can be. It also has a clearly identified location-specific need for peak charges and injection incentives.

DG can also create network costs

C.20. When injection occurs at times that demand is low, it can cause the network to incur additional costs, rather than avoid them. Too much injection at these times can cause export congestion, where future network capacity upgrades are driven by increases in peak supply, rather than peak demand. This also risks causing problems for security of supply and could mean new equipment may be needed to manage voltage stability if networks have been built to serve consumers at lower voltages and with one-way power flows. This has been a substantial problem for Australian distribution networks. While not a widely spread problem in New Zealand so far, some networks have reported issues, and the risk is likely to grow as more consumers install solar PV systems.

C.21. Generally, flexible generation such as solar with batteries is less likely to cause these issues, as its generation can generally be controlled to avoid injecting at times when demand and supply from other DG is high (for example, in the middle of the day). However, flexible DG can still cause local network constraints through 'herding' behaviour, where multiple DER is switched on or off at the same time in response to price signals that do not reflect localised network constraints. Such signals could include:

(a) wholesale market price signals, which reflect generation and transmission constraints, but not distribution constraints

(b) distribution price signals that are not granular enough to reflect localised network constraints.

[52] See Aurora, Non-network capacity solutions, https://www.auroraenergy.co.nz/how-we-manage-the-network/sustainability/non-network-capacity-solutions

C.22. The herding issue is being separately considered by the Authority as part of the ‘Updating regulatory settings for distribution networks’ workstream, but it is also relevant to how price signals for DG are set generally.

The Commerce Commission regime is relevant to distributors’ incentives

C.23. Under Commerce Commission regulation of distribution lines services, regulated distributors have financial incentives to make efficiency gains, which can be made via non-network solutions such as contracting with DG operators. Distributors subject to price-quality regulation can make higher profits if they reduce total expenditure by increasing their opex and reducing capex by a larger amount. Consumers share in this efficiency gain.

C.24. In November 2024, the Commission implemented a new Innovation and Non-Traditional Solutions Allowance (INTSA) for regulated distributors. This is intended to mitigate the risk of using non-traditional solutions to deal with network constraints. INTSA allows distributors to recover the costs for innovative projects and non-traditional solutions for projects where one or both of the following applies:

a) The benefits are sufficiently uncertain that the project wouldn’t happen without recovery of some or all of the forecast costs.

b) The project or programme is unlikely to otherwise result in any financial benefits to the EDB in the five years following the forecast completion date of the project. This is because there are no explicit financial incentives for distributors if the benefits accrue entirely to third parties or are not realised because of a change in regulatory period.

C.25. The projects encompassed by (a) above can be funded up to 75% of their project costs; projects encompassed by (b) above can be funded up to 100% of their project costs.

Appendix D Transmission cost case studies

D.1. To illustrate existing incentives for DG, this appendix presents three case studies of wholesale market effects on the operation of:

- the Kaimai hydro scheme in Tauranga in the Bay of Plenty
- the Ngāwhā geothermal scheme near Kaikohe in the Far North
- the Mangahao hydro scheme near Shannon in Horowhenua.

D.2. These case studies were selected because they were raised in submissions on the Authority's proposal to remove ACOT. We have engaged with Transpower and with the owner/operator of each of the three schemes to give them the opportunity to review this information. The Authority acknowledges and thanks their active engagement.

D.3. These power schemes differ in how they function and in their local supply and demand environments, but all three support local or regional security of supply. In all three cases, a sustained reduction in local generation would raise questions about how to maintain local security levels. Options for new transmission investments would be assessed according to economic costs and benefits. But, as the case studies illustrate, income from generation provides all three power schemes incentives to operate, making sustained reductions in generation unlikely.

D.4. In each of the case studies we use N-1 security as a reference point for reliability. This is for illustrative purposes only. The desirability of N-1 security depends on the economic costs of achieving it.

Kaimai power scheme

D.5. The Kaimai power scheme is a 42MW run-of-river hydro generation scheme with daily storage connected to Powerco's Tauranga network.[53] It is a useful case study for understanding whether wholesale market pricing provides sufficient incentives for generators to support grid reliability.

D.6. If Kaimai did not exist[54] Transpower would have had to make a substantial transmission investment to supply Tauranga long before now. However, evidence shows Kaimai has reduced and has delayed transmission investment, while the owner of the Kaimai power scheme has:

- profited from transmission investment being delayed via higher local wholesale prices
- not needed an additional incentive to operate as a transmission alternative, beyond the incentives provided by higher wholesale prices.[55]

Kaimai supports N-1 security

D.7. There are three main points of electricity supply into Tauranga (see Figure D1):

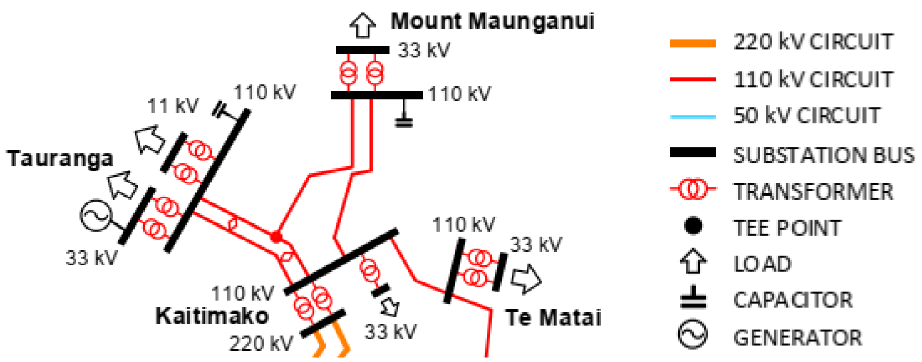
53 Manawa, Kaimai Power Scheme, https://www.manawaenergy.co.nz/kaimai-power-scheme
54 And no other generation took its place.
55 At least in 2022. Given the age and nature of the scheme, this conclusion may hold more generally.

- two transmission circuits from Kaitimako
- the Kaimai power scheme.

D.8. Kaimai is often essential for meeting an N-1 security standard. When Tauranga's demand is peaking, the two transmission circuits currently provide N-1 security only when Kaimai is generating at sufficient capacity to avoid overloading.

D.9. Load on the two transmission circuits typically exceeds N-1 capacity when Kaimai is generating at the low end of its typical range, eg, at 14MW of 39MW of maximum operating capacity. If one of the circuits trips there would be only one circuit supplying Tauranga, increasing the risk of outages.[56] Transpower and Powerco (the transmission customer) have to weigh the costs and benefits of new investments or operational changes to reduce this risk.

Figure D1: Tauranga transmission schematic[57]



Kaimai is saving consumers millions of dollars

D.10. Transpower is planning to spend an estimated $70 million between 2030 and 2035 to resolve this reliability problem.[58]

D.11. If Kaimai had indicated it was closing down or substantially reducing production below current ranges, and Transpower had to commission the new assets in 2023, it would cost Tauranga consumers $3.6 million in 2023 alone, relative to the cost of deferring commissioning until 2035.

D.12. Over the life of the asset, $36 million (value in 2022 dollars) has been saved from deferred transmission investment.[59] The cost savings would likely be higher still if the

56 This is true for all parts of the country where N-1 security levels are in operation. In places with N security this is the status quo.

57 Transpower (2023) Transmission planning report, [Transmission Planning Report 2023]

58 Transpower (2023) Transmission planning report, p.177. A smaller $500,000 investment is planned for 2025 to manage shorter-term reliability issues.

59 Approximation based on revenue requirement of 12%, split between WACC of 4.6%, depreciation of 6%, and impact on operating costs equal to 1% of the investment value. Assuming a 40-year asset life, for illustrative purposes only.

counterfactual was Kaimai closing and Transpower having to choose a substantially higher cost option to ensure reliable supply to Tauranga.[60]

D.13. Increasing Tauranga's transmission capacity today would most likely reduce Tauranga's nodal prices (which were the highest in the region on average in 2022). So, there would be some benefit from lower prices if the investment was brought forward. There would also be a benefit from improved reliability of supply.

D.14. The scale of benefits would depend on interactions with other decisions to address issues in the wider Western Bay of Plenty. Transpower's 2023 planning report notes

> *An investment to address one issue may assist in mitigating other issues or may make other issues worse. Many of the interacting issues also occur only a few years apart, especially for the Western Bay of Plenty area (Kaitemako, Tauranga, Mount Maunganui and Te Matai).*

D.15. But, by way of example, if Tauranga's nodal prices fell to the level observed at Kaitimako (0.3 percentage points lower) Tauranga consumers would save an estimated $400,000 in 2023 if the investment had proceeded today.[61] Over the life of the project, the saving would be $2.3 million.[62]

D.16. In this example, Kaimai saved Tauranga's consumers $3.2 million in 2023. This saving is what Kaimai's owners appear to be suggesting should be shared with them as it is a benefit provided by Kaimai.[63]

But Kaimai does not need an additional incentive to operate

D.17. There is no doubt consumers have benefitted from the cost savings provided by Kaimai. But it does not follow that additional compensation is required to keep Kaimai delivering those benefits.

D.18. The Kaimai scheme receives a premium on its output via wholesale electricity prices for operating in an area where transmission is constrained. Put another way, Kaimai's owners profit from any delay in transmission investment.

D.19. The size of Kaimai's premium for operating in a constrained area is not large relative to consumers' savings from deferred transmission investment. As shown in Table D1, Kaimai earned around $600,000 from losses and constraints in 2022.[64] However, it is a 3.5% premium over revenue earned purely for energy (the Energy component of

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60 There are additional hypothetical cost savings, for example, the counterfactual to Kaimai operating could be Kaimai shutting down suddenly and sustained load shedding because the grid owner had not anticipated the closure. Such a sudden shutdown scenario is extreme and could equally be applied to any number of grid-connected generation, especially in the current environment. So we do not consider that to be a bona fide benefit (avoided cost) in this scenario.

61 A 4% price fall is required to offset the costs of bringing forward the investment. This would require Tauranga's location factor to fall to the level observed at Kawerau, which is very unlikely given the Tauranga investment is addressing a localised constraint and Kawerau is somewhat unique in having a large generation surplus and grid injection constraints.

62 Assuming national wholesale prices remain at 2022 levels and Tauranga's demand rises at 1% per annum. In 2022 expenditure on energy at the Tauranga GXP was approximately $100 million.

63 Calderwood Advisory Ltd 2022, p5: "to be compensated for providing support services from KMI".

64 The loss and constraint value includes constrained-on payments.

revenue in Table D1) at the reference energy price.[65] It is also a premium that generally rises with demand (in dollar terms), therefore incentivising generation at times of high demand.

D.20. Indeed, Kaimai does tend to offer to generate more during periods of high demand. As shown in Table D1, its output offered jumps from 64% of maximum in the 9th decile of demand to 81% of maximum in the 10th decile of demand. To do otherwise would reduce profits, not least because prices paid for generation located at Tauranga (the Nodal price in Table D1) are, on average, at their highest during the highest deciles of demand.

Table D1: Wholesale generation revenue for Kaimai DG in 2022, by decile of demand at the Tauranga GXP[66]

Decile of demand	Generation (MWh)	Nodal price ($/MWh)	Cost of offers ($)	% of max output offered	Revenue ($)	Energy +	Losses and constraints
1	4,900	12	0	13%	55,800	57,500	-1,700
2	5,700	29	100	14%	158,200	163,500	-5,300
3	8,100	36	2,100	22%	302,600	306,900	-4,300
4	14,500	38	24,200	43%	554,000	549,600	4,400
5	19,000	53	78,900	55%	1,060,600	1,026,400	34,200
6	20,200	84	106,500	60%	1,745,300	1,668,400	76,900
7	18,800	109	162,400	57%	2,110,100	2,049,500	60,600
8	20,600	155	350,100	61%	3,166,300	3,065,600	100,700
9	21,900	176	299,000	64%	3,875,900	3,751,300	124,600
10	27,000	208	388,900	81%	5,506,200	5,277,100	229,100
Total	160,700	115	1,412,200	57%	18,535,000	17,915,800	619,200

D.21. Kaimai has, at least since 2019, offered small tranches of its generation (eg 7MW of a maximum of 40MW) at values in the hundreds of dollars per MWh – signalling scarcity value of its generation especially during peak demand periods. While this shows sometimes its generation is not dispatched (eg 4% of the time during the top decile of local demand), it also means the scheme gets an additional premium if it is

65 The reference energy price used here is the price at Haywards. This is a proxy for the cost of energy in the absence of all losses and constraints. The premium calculated here therefore reflects a counterfactual of no losses or constraints across the entire grid. If this premium is calculated based only on a counterfactual of reduced local losses between Tauranga and Kaitimako, the value would be $60,000. If the premium is calculated based on a counterfactual of reduced losses and constraints within the wider Western Bay of Plenty the value would be in $230,000 (based on prices at Tarukenga).

66 Values in the table have been rounded to the nearest 100MWh and the nearest $1000.

constrained. This sort of offer strategy is likely efficient if it is signalling an opportunity cost, for example, if generating in the morning peak would reduce capacity available for the evening demand peak. Note, the 'cost of offers' column in the table above is equal to the offer price multiplied by dispatched generation.

D.22. Notably, there will be minimal or no cost to generate at any particular time, but there may be some cost associated with paying close attention to trading conditions. Regardless, generating during peak times, when prices are likely to be higher, offers the prospect of substantially higher operating profit.

D.23. Strategically, if Kaimai fails to generate during peaks, it will increase the likelihood of new transmission investments that will result in lower nodal prices and lower profits. This strategy is likely to be considered by those planning maintenance outages of the generator.

D.24. There also seems little prospect of the plant not making a reasonable return on capital that may cause it to close. Operating and maintenance costs are likely to be in the range of $1.5 million to $3.5 million dollars per year,[67] which is well covered by revenue.

Kaimai's contributions are partly coincidental

D.25. Incentives to generate at peak times, or at least for local peaks, are not as sharp as they might be if nodal pricing was based solely on local conditions, instead of reflecting total system costs and demand and generating capacity across the national network. But it is unclear if sharper incentives would lead to higher probabilities of maximum generation at peak times, at least in the case of Kaimai. It would be highly inefficient if stronger price signals meant higher profits for actions that would be taken anyway.

D.26. Kaimai is effective at targeting the highest peak periods. Though it is described as run-of-river, Kaimai does have sufficient storage and controllability to shift some of its generation within the day.[68] This can be clearly seen in Figure D2[69] below where generation from the scheme broadly tracks intra-day demand patterns at Tauranga, particularly during the high demand winter months. Kaimai also has reliable base flows, with relatively consistent year-round rainfall in its catchment and a broad catchment area.

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67 Based on a range of $40/kW and $70/kW.

68 Lilley, P 2018, Statement of Evidence of Peter Lilley https://www.boprc.govt.nz/media/723890/trustpower-soe-peter-lilley.pdf

69 This was a relatively wet year, with above average rainfall in the second half of the year when the scheme regularly ran near capacity in the middle of the day. In drier months output was lower.

Figure D2: Kaimai power scheme, intra-day generation – 2022 data
Blue lines are fitted trend lines, grey dots are half-hourly observations

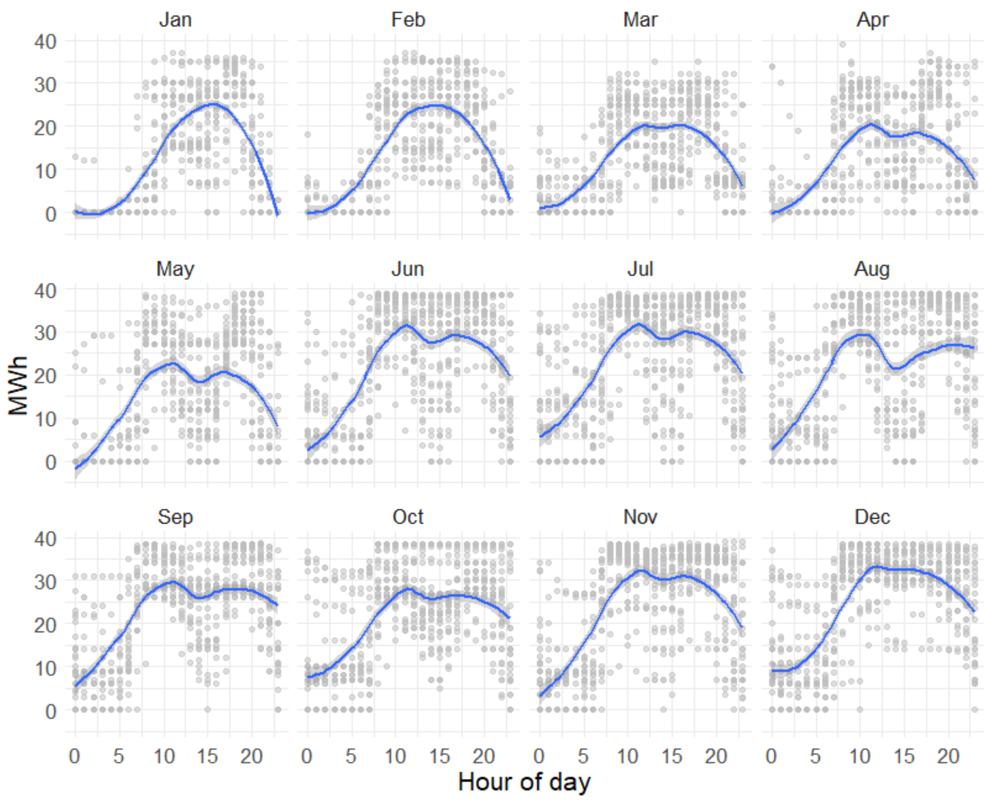
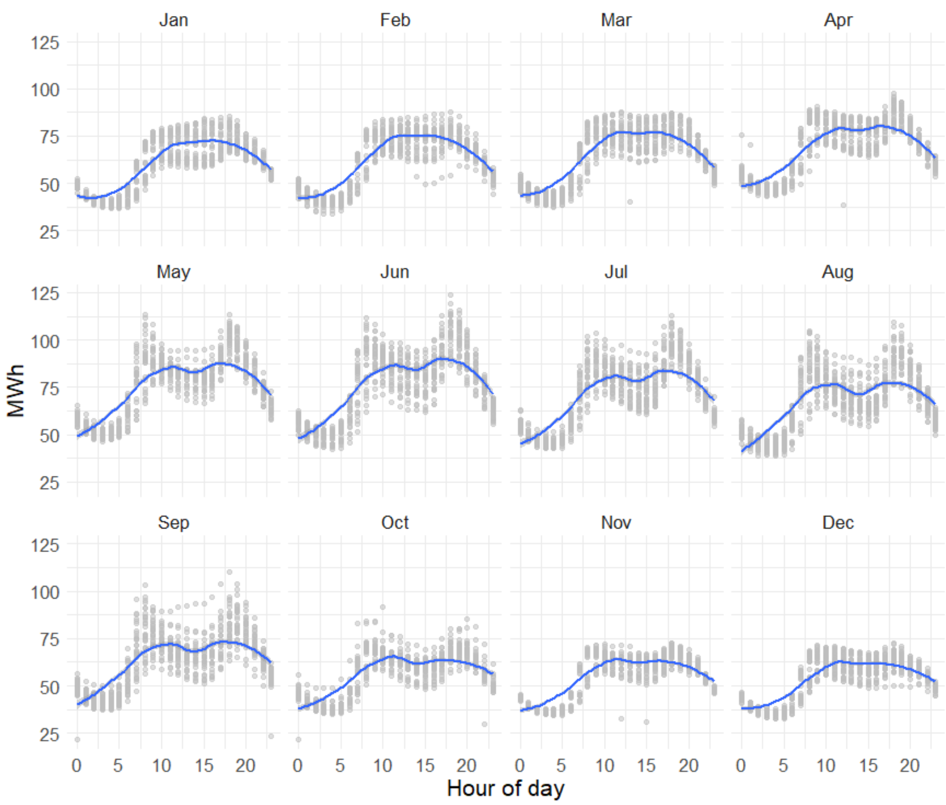


Figure D3: Tauranga grid exit point, intra-day load – 2022 data
Blue lines are fitted trend lines, grey dots are half=hourly observations



D.27. However, there appear to be limits to Kaimai's capacity utilisation during high demand periods in that there are limits in its ability to generate near capacity consistently for several hours. This can be seen by the number of periods where the power scheme is operating well below maximum capacity, but demand is high. See the middle row of Figure D2, for the colder months when demand is high (see D3). Where there is a close alignment between the trends in generation (Figure D2) and trends in load (Figure D3) the generation pattern has much higher variance.

D.28. In this respect, Kaimai generating at maximum when demand is high and support for grid reliability may be needed is at least partly a coincidence.

An imperfect transmission alternative

D.29. Kaimai's variable output makes it an imperfect transmission alternative because it cannot be relied upon to generate predictable as and when required.

D.30. If the scheme could be expanded or a similar scheme installed, this would have the benefit of further deferring transmission investment.

D.31. That might be a situation that could prompt demands for a side-payment, such as a Grid Support Contract by Transpower to expand the plant or install a similar scheme. However, the business case for the generation plant would primarily rest on the wholesale market revenue obtained from what would be a very substantial capital-intensive project. Therefore, a side-payment from Transpower would likely be a minor consideration, at least in this case study.

D.32. If additional generation (equivalent to a new Kaimai scheme was likely to be profitable, a payment for deferring transmission would do little to entice investors. This is analogous to the supply of inertia by thermal plant. It is not the primary purpose of the plant, nor does the additional service add additional costs. Therefore, compensation is unnecessary and would only add costs to consumers.

Ngāwhā power scheme

D.33. Ngāwhā is a 57MW geothermal generation scheme located near Kaikohe in the Far North, in Top Energy's network.

D.34. This scheme is considered DG by virtue only of its connection to a transformer owned by Top Energy – with Transpower owning only the transmission lines into Kaikohe. This illustrates the difference between distributed and grid-connected generation is often an incidental reflection of institutional arrangements of ownership, rather than a description of a materially, technically, or economically different type of generation.

Ngāwhā provides local N-1 security

D.35. Transpower's 2022 transmission planning report[70] says peak demand at Kaikohe is not expected to exceed N-1 security of supply standards for the foreseeable future. However, that would not be the case if Ngāwhā closed.

70 Transpower, Transmission Planning Report, 2022, 2022 Transmission Planning Report.pdf

D.36. Ngāwhā supports wider region's reliability by reducing growth in grid demand. Transpower takes account of this when it considers risks to regional reliability and investment options.

D.37. Transpower also takes account of the potential need for new transmission investment to enable large amounts of new generation to be located in Northland, such as if there was an expansion of geothermal generation at Kaikohe.

Ngāwhā does not need incentives to provide local N-1 security

D.38. Ngāwhā does not need additional incentives to generate at or near capacity during peak demand periods.

D.39. Ngāwhā is baseload plant, suited to running continuously near capacity most of the time. Figure D4 below shows the flat generation profile through the year contrasted against revenue, which is much higher during peak demand periods when prices rise.

D.40. It also seems implausible that Ngāwhā would close if it were not rewarded for providing N-1 security:

D.41. The newest plant at Ngāwhā is only three years old and its capacity is sufficient for N-1 security, according to Transpower[71]

D.42. The plant is unlikely to become uneconomic due to deficits in operating revenue because it has relatively low annual operating costs – many times smaller than annual average revenue is ever likely to be.[72]

D.43. Hypothetically, there might be a case for financial incentives beyond the standard wholesale or contract market mechanisms to keep Ngāwhā's older (OCE 1,2,3, 27 MW) units operating, if the units required major refurbishment and that investment was not commercially viable.[73]

D.44. Closure of the older generation units at Ngāwhā would likely bring forward transmission investments. However it is unclear what these investments would be. Transpower would need to investigate the implications for the wider region and consider the scale and timing of any new investments.

D.45. But, by way of illustration, Transpower's 2022 planning report indicated that $3.5 million of transmission investment planned for 2025 to 2030 could be brought forward if Ngāwhā's capacity was reduced.[74] The cost of bringing forward that investment will likely be about $900,000.

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71 Therefore the closure of the older 27MW of generation at Ngāwhā would not pose reliability risks at Kaikohe.

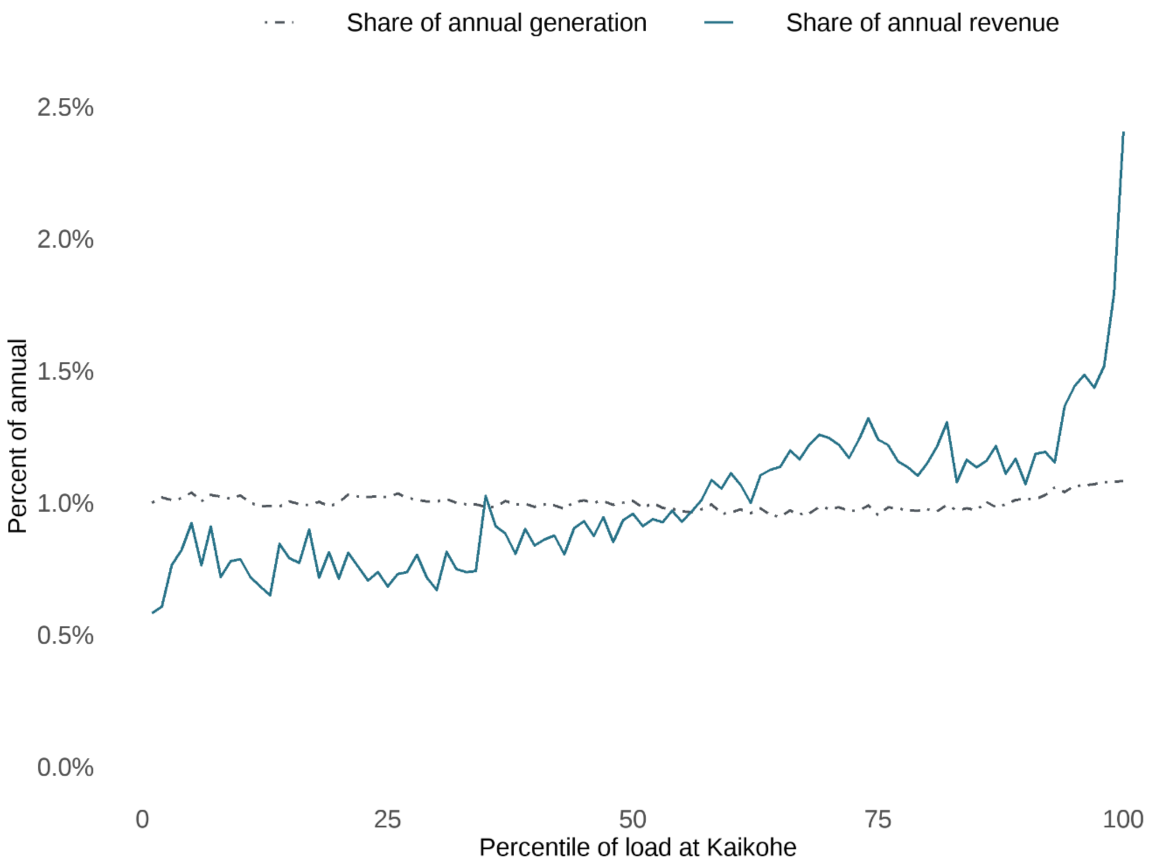
72 Based on annual operating and maintenance costs of $5.6 million (cost per kW from https://www.mbie.govt.nz/assets/future-geothermal-generation-stack.pdf), which amounts to around $30/MWh. Ngāwhā does produce higher greenhouse gas emissions than other geothermal plants in New Zealand, and while that would imply higher than average operating costs, those gasses are reinjected so they do not attract emissions costs.

73 This issue has been raised by Ngāwhā Generation Limited in its 'Submission on ACOT – proposed TPM-related amendments' October 2022.

74 One of the planned investments, an upgrade of thermal circuits planned for 2034, is not yet costed. And in any case, upgrading transmission lines north of Henderson may yet occur to support increased generation in Northland rather than manage the consequences of increased load at Kaikohe if part of Ngāwhā shut down. That being so, we focus here on the more imminent investments.

D.46. In addition, if Ngāwhā's capacity is reduced, Top Energy would need to decide whether to increase the security level of its connection to the grid. Top Energy owns some of those connection assets, so it could consider the option of paying Ngāwhā to keep running at current capacity to avoid the costs of upgrades, and pass payment costs to Ngāwhā on to distribution customers.

Figure D4: Ngāwhā generation and revenue by demand percentile, 2022



High standard of evidence required for any payments for avoided transmission

D.47. The case for pursuing payments to avoid the costs of asset upgrades would need to:

(c) demonstrate the need for such a payment, for example, by establishing a credible risk of closure

(a) identify the minimum value of a payment that would keep the plant in operation

(b) show there is not a cheaper alternative, whether network investments or alternative energy generation investments or demand response

(c) demonstrate investment in new generation or load would not eliminate the benefits of keeping the plant in operation

D.48. Transpower has said increased generation investment in Northland could cause injection constraints

D.49. Top Energy has commenced planning for a possible 25MW expansion of Ngāwhā's capacity in 2028 that would eliminate any case for payments to keep the older generating units in operation

D.50. A substantial amount of new generation, including grid-scale batteries, is consented or being planned in the Far North and may similarly eliminate any case.

Mangahao power scheme

D.51. Mangahao is a 38MW hydro generation scheme notionally embedded in Electra's distribution network with a direct connection to Transpower's network via the 33kV bus near Shannon in Horowhenua.

Mangahao supports N-1 security

D.52. Transpower's 2023 transmission planning report[75] says: "Peak load at Mangahao already exceeds the n-1 capacity of [the grid] supply transformers" if the Mangahao hydro scheme is not generating.

D.53. Transpower will discuss with Electra augmenting the capacity of the supply transformers when they are considered for replacement around 2026-2028.

Mangahao provides substantially less security than the grid

D.54. Mangahao is an imperfect substitute for reliability provided by the transmission grid because its generation is more intermittent than grid supply. While it may assist with N-1 security a lot of the time, and can be used to target pre-specified periods of peak load, the intermittency of its output suggests it cannot be fully relied upon to operate as a transmission alternative.

D.55. Figure D5 illustrates the intermittency of Mangahao. The graph shows trading periods in 2022 where load is above 30MW and security falls below the N-1 standard unless Mangahao is generating enough to reduce net load below 30MW. During those periods, in 2022, generation and offers from Mangahao were not providing N-1 security as they were zero around 7% of the time. This means Mangahao is not as reliable a source of security as transmission assets, for which failure rates are substantially lower than 7%.[76]

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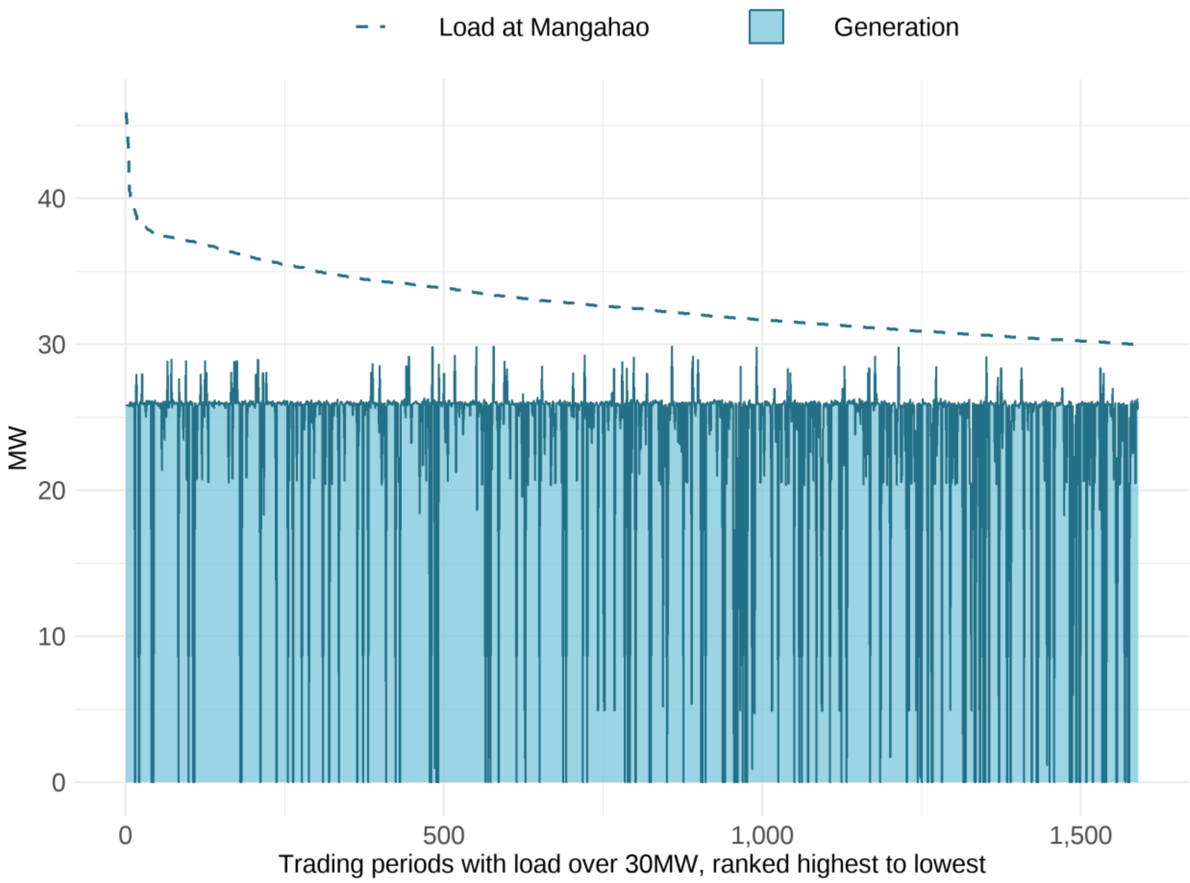
75 Transpower, Transmission Planning Report 2023

76 Synergies, ndependent Verifier's review of Transpower's RCP3 expenditure proposal, https://comcom.govt.nz/__data/assets/pdf_file/0019/123490/Supplementary-information-in-support-of-the-Independent-verification-report-February-2019.PDF

Figure D5: Mangahao generation – 1590 highest demand periods during 2022



D.56. There have been periods where Mangahao has been more effective in providing reliable supply during peak periods of high demand. For example, in 2017 Mangahao generation provided security of supply in 97% of periods where load was 30MW or higher.[77]

D.57. But there have been periods where Mangahao performed substantially less effectively. In 2020, Mangahao did not provide N-1 support in 14% (169) of trading periods when load was above 30MW (1,201 trading periods).

Avoided cost of transmission payments reduced reliability at Mangahao

D.58. Historic observations do need to be considered cautiously however, as ACOT payments skewed Mangahao generation towards supply during the top 100 lower North Island peaks rather than local demand peaks and Mangahao. Between 2007 and 2022 Mangahao generated:

- below 1MW in 5% of the top 100 local demand peaks, but only in 0.6% of the top 100 regional coincident demand peaks

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77 This may be why Transpower's 2018 transmission planning report in the following year noted that "Mangahao generation is usually available during peak load periods so the probability of constraint is very low" (p. 73).

- at an average of 26.5MW during the 35% of top 100 local peaks that coincided with the top 100 regional coincident peak periods, but at an average of 24.5MW during the 65% of top 100 local peaks that did not coincide with the top 100 regional coincident peak periods.

Other incentives would do little to improve reliability

D.59. We might have expected higher average generation during local demand peaks if ACOT payments had been tailored to local grid constraints, with incentives matched to the timing of local grid constraints and local demand rather than lower North Island coincident peak demand.

D.60. However, the Mangahao scheme does not appear capable of operating at high capacity for long periods to consistently provide N-1 security. While Mangahao is a scheme with some storage and capability of moving capacity between time periods, data on generation over a year shows there are limits to this capacity. This can be seen in Table D2, which shows Mangahao would generate more revenue if it could shift its generation into periods with higher prices, yet its generation is lower on average during higher priced periods, indicating material operational constraints shifting generation into high priced periods.

D.61. In 2022 an above average share of Mangahao's generation was in the third decile of prices, when demand was relatively low. In those periods, generation was being offered at material volumes (greater than 1MW) 65% of the time. This contrasts with the highest priced and highest demand periods where Mangahao offers were larger than 1MW only 50% of the time.

Table D2: Mangahao generation by decile of final price, 2022

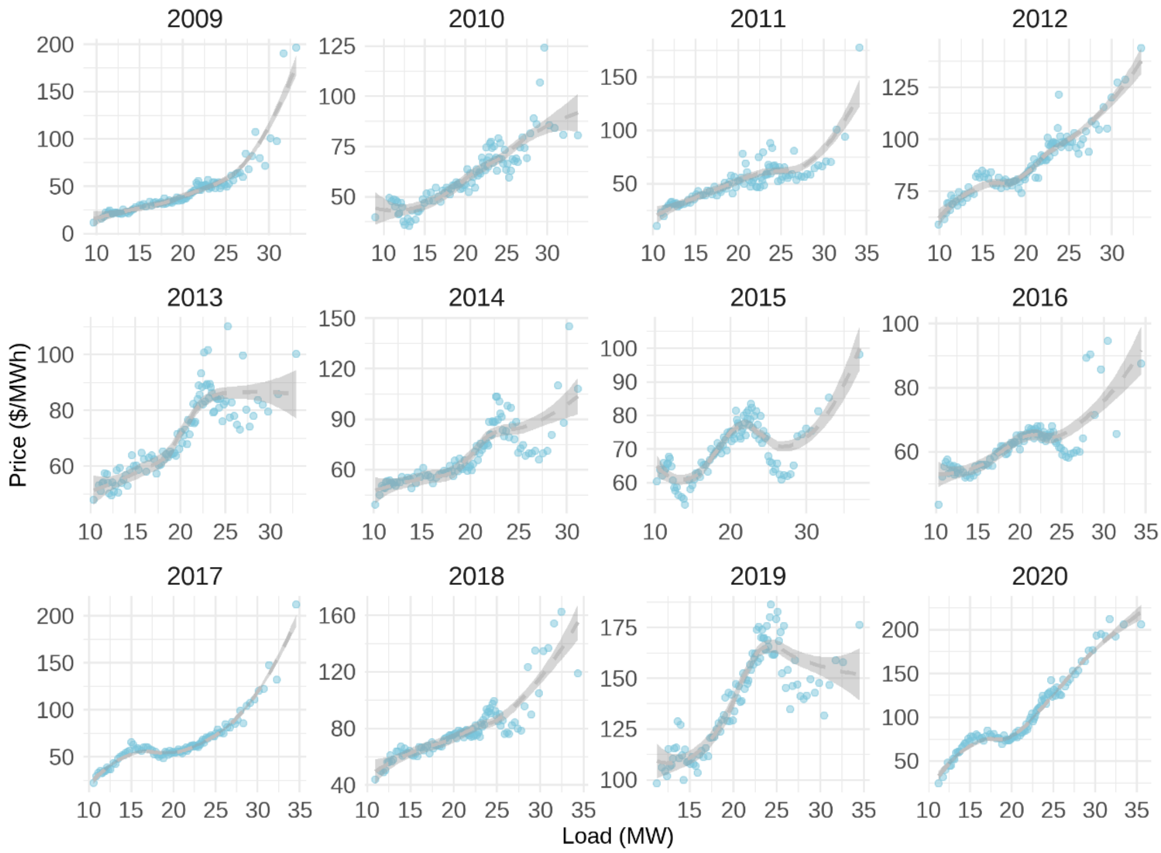
Price decile	Price (average $/MWh)	Offers of less than 1 MW (% of offers in decile)	Generation (% of annual)	Local demand (MWh)
1	0.04	60%	7.2%	33,310
2	4	44%	10.5%	36,488
3	13	35%	13.2%	38,684
4	58	36%	13.1%	38,208
5	95	46%	11.1%	39,596
6	140	45%	11.4%	40,632
7	170	57%	7.8%	37,125
8	189	65%	6.7%	35,820
9	207	51%	9.0%	40,721
10	284	50%	10.0%	45,444

D.62. The relatively low generation we observe during high priced periods may be partly a result of difficulties predicting prices. But that does not explain the substantially lower generation across periods where prices are consistently higher.

D.63. It is possible to identify periods where prices are likely to be higher than average is not so difficult (see for example Figure D6 showing a consistent if imperfect positive relationship between demand and prices). There are certainly sufficient commercial incentives to generate more during high demand periods.

Figure D6: Prices and load at Mangahao

Observations in dots are means per percentile of load. Panels are split into transmission pricing capacity measurement years ending 31 August. Gray shaded areas are standard errors around a smoothed trend.



D.64. There may be other commercial reasons for low generation in some high-priced periods, but overall, the relatively low amount of generation offered from Mangahao during periods of high prices and high demand (Table D2), suggests the scheme is not capable of consistently responding to existing incentives to act as an appropriate substitute for transmission. This suggests the support it does provide is at least partly coincidental, and other incentives would do little to change that.