Consultation draft: cost-benefit analysis for multiple trading relationship and switching

Prepared for the Electricity Authority

Ashley Milkop, Angus White and Peggy Alivianur
23 January 2026

Contents

Appendices

Tables

Figures

Glossary

Abbreviation	Stands for
BSC	Balance and Settlement Code
CBA	Cost-benefit analysis
DER	Distributed energy resources
DNO	Distribution Network Operator
EV	Electric vehicle
ICP	Installation Control Point
MEP	Metering Equipment Provider
MTR	Multiple trading relationships
MW	Megawatts
PV	Present value
UK	United Kingdom

Executive summary

The Electricity Authority engaged us to provide cost-benefit analyses of its proposed changes to support multiple trading relationships (MTR) and switching, having adapted its proposals in light of feedback during consultation. The analysis included in this report draws on stakeholder inputs provided during the Electricity Authority's (the Authority) initial consultation as well as other sources.

With the change in design of the preferred proposal (in light of feedback received during consultation), it is intended that key (particularly cost) assumptions be further tested with stakeholders. This consultation draft is intended to support that process and elicit further information to inform assumptions, with a final report to pick up any adjustments required in light of feedback on the new Revised Proposal (and its expected impacts).

We estimate the breakeven benefits needed in the package components, noting synergies and unquantified benefits

The proposed changes are presented as a package, involving several shared costs and complementarities. There is conceptual logic and rationale for the proposed adjustments; however, given the limited information available to quantify the expected benefits, or range of benefits, from the proposals, we have adopted an approach that estimates the breakeven level of peak capacity required to justify the costs associated with MTR, as well as the level of savings needed from switching changes to justify their associated costs. It should be noted that there is some risk of double-counting costs between the MTR and switching proposals (though we have tried to minimise this risk). There are also likely synergies and additional unquantified benefits beyond those captured in the estimated breakeven analysis.

Benefits of at least $38 million are needed across MTR and switching proposals to match currently estimated costs

We estimate that if an additional 0.36 to 1.77 per cent (or more) of existing and planned residential battery installations are fully deployed in response to MTR incentives to reduce peak consumption, this component of the proposal would deliver benefits exceeding costs in present value terms. Furthermore, switching components are likely to break even for most participants; our estimates indicate that a reduction of approximately 20 to 44 per cent in the total cost of problematic switches would be required for these components to yield net benefits in present value terms.

Table 1: Summary present value of costs and breakeven levels of benefits

Costs and benefits	Value
MTR costs	$22.8 million - $25.4 million
Switching costs	$12.0 million - $12.7 million
Quantified switching benefits	$5.0 million - $ 5.1 million
MTR breakeven percentage of additional battery capacity responding to peak reduction incentives	0.36% - 1.77%
Switching breakeven reduction in total cost of problematic switches	20% - 44%

We note this assumes benefits are cumulative or coincidental and not mutually exclusive (i.e. reducing thermal peaking is not at the expense of reducing new lines and generation costs) and excludes any potential additional costs to develop algorithms to engage with the wholesale market. However, we have not quantified any potential benefits from electric vehicles (EV) or increased solar/battery uptake, any potential extensions of the Revised Proposal (such as extending to load management or peer-to-peer trading/community sharing), or any potential competition benefits from additional participants such as aggregators entering the market, although we have provided a description as to how some of these mechanisms may come into play.

Limitations

This analysis has been undertaken over a tight timeframe with limitations in the data available from which to estimate costs and benefits. Our approach has been tailored in light of this; however, these are limiting factors in terms of the analysis that is able to be taken and therefore confidence:

Some of the initiatives relate to an emerging space which makes it impossible to reference another real-life example. A number of the quantitative estimates/indicators we do have relate to a proposal that has since been amended, specifically to try to manage costs and involve divergent estimates (which may reflect variation in the level of impacts across participants, information availability, and/or levels of support). Further, how participants react in response to proposed changes is difficult to predict, making ongoing dynamic impacts difficult to estimate. There is also the potential for double-counting of certain costs and benefits. We note that the MTR benefits we have identified lie within a particular subset of the distributed generation space.

In light of this context, where there is insufficient basis to provide estimates, we note qualitative and uncertain impacts and apply breakeven analysis to aid overall consideration of the Revised Proposal.

1. Introduction

The Electricity Authority (the Authority) has engaged us to provide cost-benefit analyses of its proposed changes to support multiple trading relationships (MTR) and switching, which is the focus of this report.

1.1 This analysis builds on prior work and engagement by the Authority

In early 2025, the Authority consulted on proposals to enable MTR and improve switching. MTR enables consumers to contract with more than one retailer at the same property. For example, one retailer for electricity consumption and another for generation. The proposals are intended to improve consumer choice and may promote investment in and/or the deployment of distributed energy resources (DER), which may reduce peak consumption, strengthen regional resilience, and reduce reliance on the national grid. Alongside this, improvements to switching processes are intended to make it easier for customers to change retailers quickly and confidently.

The consultation paper outlined proposals for the first stage of enabling MTR. These changes focus on:

- allowing separate retailers for consumption and generation at a property
- aligned switching processes.

Most stakeholders who engaged in the Authority's consultation process agreed with the overall goals of the MTR and switching changes of more flexibility, competition, and innovation. However, many raised concerns about the original MTR proposal, saying it was too costly, complex, and would only benefit a small group of consumers. Following this, the Switch and Data Formats Group suggested an alternative approach (referred to here as the Revised Proposal) which uses the existing registry to manage MTR trades. This Revised Proposal would require fewer system changes, cost less, and could be implemented faster while still supporting future innovation.[1]

The Authority is now considering implementing this Revised Proposal which would involve investing in upgrading the registry to enable it to split out MTR flagged trades (generation) from installation control point (ICP) trades (consumption), and only customers that adopt MTR would see the changes in the registry. The implication would be minimal change to existing ICP-based trades (currently 97 per cent of the market), thus avoiding costly IT system changes for many participants.

The Authority expects these changes would deliver real benefits by lowering barriers to entry for new retailers and innovators, improving consumer experience through better switching processes and encouraging uptake of distributed generation, which enhances sustainability and resilience.

[1] The original Option 1 was to change systems from ICP-level data to meter-level data to enable two traders to be on the same meter. All participants would have needed to alter their systems to provide meter-level data.

1.2 Similar proposals have been explored internationally

MTR has been discussed in multiple jurisdictions to varying depths. New Zealand can draw several important lessons regarding the consideration/implementation of multiple trading schemes from experiences overseas. This is particularly true in relation to the cost of policy implementation, regulatory structure, and market incentives. We elaborate below on Australia and the United Kingdom (UK). We note that neither of these jurisdictions have opted to pursue MTR arrangements, but Australia revisited the idea through an MTR-like arrangement[2] (SEEK New Zealand, n.d.; World Salaries, n.d.), and we note other jurisdictions have implemented aspects similar to MTR (such as the United States and Canada).

Australia and the UK elected not to pursue MTR

In Australia, the initial proposal to enable MTR, allowing customers to engage multiple retailers without needing a second physical connection point, was ultimately rejected because the potential societal and economic benefits were deemed insufficient to justify the high cost (Australian Energy Market Commission, 2016). It was judged that implementing the proposed framework required retailers and distributors to undertake significant and complex modifications to their IT systems and operational processes, which were built around the existing one-to-one relationship between the connection point and the financially responsible market participant and would have been passed on to all electricity customers through increased retail prices (Australian Energy Market Commission, 2016).

In the UK, the energy market has traditionally been governed by the supplier hub model.[3] This model dictates that a domestic consumer's interaction with the entire energy system is mediated by a single licensed supplier (Watson, 2022).[4]

A proposal including MTR components in the UK, P379 'Multiple Suppliers through Meter Splitting' consultation opened by Elexon,[5] was ultimately withdrawn following feedback. An independent consultant report by CEPA as part of the P379 consultation found that enabling the proposed meter splitting would require large-scale, cross-industry system changes**,** affecting settlement systems, metering arrangements (this includes smart metering), registration systems, data flows, and supplier

[2] This arrangement introduces secondary settlement points (an additional metering and settlement arrangement behind a single physical connection point). Only certain loads (e.g., EV charging) or generation (e.g., solar) are allocated to the secondary point.

[3] In the UK energy retail, the Supplier Hub Principle means the energy supplier acts as the single point of contact for customers, managing billing, metering, and coordination with other market participants to simplify the customer experience and ensure accountability.

[4] Challenges have been suggested with this model in the UK in relation to market power and barriers to entry. The model has been suggested to lock in large energy suppliers as the central interface, leading to them maintaining an "enormous amount of market power," hence has been suggested to present a significant burden and financial risk for non-traditional suppliers (e.g., those with geographically limited or specialised markets) (Watson, 2022). Current multi-party supply arrangements must either contract through a licensed supplier (e.g., through white-label or sleeving agreements) or are subject to extremely high overhead costs, making them prohibitively expensive for domestic end-users (CEPA, 2020).

[5] Elexon administers the Balancing and Settlement Code (BSC): the rulebook for the wholesale electricity market under the New Electricity Trading Arrangements (NETA).

billing platforms. As noted, the proposal was eventually withdrawn after analysis indicated that implementation costs were expected to be significantly higher than originally expected and that many intended benefits were already being addressed through other reforms. Further background in relation to feedback received in the UK is set out in Appendix B.

The UK proposal was more complex than what the Authority proposes

Note that there is a fundamental difference in the design of how MTR was proposed to work in the UK. What is known as P379 aimed to let multiple suppliers serve a single meter point across different loads, appliances, or behind-the-meter generation, not just export vs. import. This means that the proposed arrangement by the Authority is much simpler and low-cost in nature compared with what was considered in the UK.

CEPA concluded that it may still be worthwhile to revisit the idea of meter splitting, particularly in about five years (CEPA, 2020). This is because the costs and benefits of P379 are highly sensitive to wider market developments, consumer readiness, future changes and the UK's comparatively slower progress in smart meter adoption. What this means for the UK market is that there may need to be additional time before the enabling infrastructure and consumer participation levels are sufficient to realise the full potential of such reforms.

Smart meter penetration is much higher in New Zealand

MTR arrangements are most beneficial when paired with smart meters. Without smart meters, MTR may become impractical because manual meter reading cannot deliver the frequency, precision, or cost-efficiency needed for multi-party settlement. Jurisdictions with near-universal smart meter coverage, like New Zealand, are well-positioned to implement MTR effectively, whereas regions with lower penetration face significant operational and cost barriers that could undermine the benefits of such arrangements.

In our research, we note that smart meter penetration varies across countries. In New Zealand, more than 80 per cent of households have smart meters installed, reflecting near-universal adoption in recent years (Styles, 2022). According to the Authority, this number has been higher in recent years climbing up to around 94 per cent.[6] By contrast, in 2020 Australia had achieved only around 17.4 per cent (Keen, 2024), increasing to 57 per cent, remote meter reading coverage across its national electricity market (AEMC, 2024). When making its decision on MTR, remote meter reading penetration would therefore have been expected to be less than 17.4 per cent. In the UK, approximately 67 per cent of meters are smart or advanced, with about 61 per cent operating in smart mode (Department for Energy Security and Net Zero, 2025). Aside from smart meter penetration, we note that discussions in other jurisdictions indicated that the most substantial components of costs typically stem from policy implementation and associated system upgrades.

[6] The Authority's consultation paper references 93 per cent penetration (Electricity Authority, 2025) and more recent EMI headline estimates (as at 31 December 2025) indicate 94 per cent penetration.

1.3 We estimate the benefits needed in light of estimated costs

This report provides a cost-benefit analysis of implementing MTR in retail electricity as well as the proposed switching processes. It examines the financial and non-financial impacts of the proposed changes, informed by stakeholder feedback on the original proposal during consultation, and assesses the scale of benefits where the MTR and switching changes would produce benefits that would exceed the identified (and more easily quantified) costs.

The remainder of this report covers:

- the methodology and options analysed (section 2)
- costs analysed (section 3)
- benefits analysed (section 4)
- impact assessment and conclusion (section 5).

These sections are followed by providing references and a full set of assumptions and their basis in Appendix A.

2. Methodology and option analysed

Here we discuss the method used in undertaking our modelling and the relevant options, before discussing the costs and benefits of the Revised Proposal relative to the counterfactual in the following sections.

2.1 Breakeven analysis is used consistent with the Treasury's CBA guidance

Our analytical framework considers impacts on stakeholders over a 15-year period. We follow a cost-benefit analysis (CBA) framework that applies scenario modelling, using economic modelling to analyse impacts under the Revised Proposal relative to a counterfactual base case (i.e. what would occur in the absence of intervention).

In line with the New Zealand Treasury's *Guide to Social Cost-Benefit Analysis* and CBA guidance, this approach ensures transparency and consistency by defining a clear "business as usual" baseline (or counterfactual), monetising costs and benefits where possible, applying the Treasury's recommended public sector discount rates, and testing assumptions through targeted sensitivity and scenario analysis. Table 2 sets out the key assumptions/parameters applied in our analysis with a more complete list included in the Appendix A.

Table 2: Key assumptions in our analysis

Assumption	Value	Description
Offset thermal peaking	$118 per kW per annum[7]	This value represents the thermal peaking cost avoided due per each kW of battery deployed.
Offset new lines and generation	$241 per kW per annum[8]	This value represents the avoided cost of building new infrastructure per each kW of battery deployed.
Discount rate	2% as default;[9] 8% sensitivity	The discount rate determines how future costs and benefits are valued in present terms. A higher discount rate makes future benefits and costs less significant.
Period of analysis	15 years 25 years	Sensitivity of 15 years per the Authority's approach.

Costs are informed by submissions, the Authority and relevant research

The cost component of our analysis is informed by submissions received by the Authority on its original proposal and subsequent discussions in relation to the Revised Proposal, and aligns with

[7] Cost-benefit analysis of distributed energy resources in New Zealand - A report for the Electricity Authority - David Reeve, Toby Stevenson, Corina Comendant, 7 July 2021, revised 13 September 2021.

[8] Ibid.

[9] The New Zealand Treasury CBA guidelines specify two per cent (real, pre-tax) for the first 30 years of projects or policies that are not primarily aimed at generating financial returns. Instead, they focus on delivering social, or public benefits.

discussions in other jurisdictions, where the most substantial components of costs typically stem from policy implementation and the associated system upgrades.

As outlined in Section 3, we have separated costs for MTR and switching proposals. However, we acknowledge synergies between these changes and, where appropriate, apply cost reductions to reflect these overlaps, ensuring we do not overestimate the overall impact.

This report focuses on comparing counterfactual (baseline) and factual (proposed change) scenarios. Where relevant, we have incorporated sensitivity tests into the factual scenario.

We employ a breakeven approach given the information gaps for assumptions on the scale of certain drivers of benefits

We also recognise that there are several approaches to concluding a CBA or ranking options, including breakeven analysis, net benefits, and benefit–cost ratios. For the MTR and switching proposals, we consider breakeven analysis to be the most appropriate method. Breakeven analysis identifies the point at which benefits equal costs, offering a clear and practical benchmark for decision-making. This approach is particularly valuable where benefits are uncertain or vary significantly across scenarios, as it helps stakeholders understand the minimum level of uptake or performance required for the proposals to be economically viable.

2.2 The Revised Proposal (factual) is compared to the counterfactual

We examine the package of changes under the Revised Proposal relative to the counterfactual of what would occur without these changes. While the changes are analysed in two parts as the drivers for each to break even is different, these parts form one combined package of changes. Below we set out the counterfactual and factual (Revised Proposal).

2.2.1 Counterfactual

> Not adopting the MTR and switching policy means customers' meters are connecting at the ICP level using existing processes. One premises connects to one retailer for both import and export.

In this scenario, the consumer will continue to have very limited ability to contract separately for components of their electricity retailing (requiring separate metering and incurring separate distribution charges). While this reflects the current status quo, other factors are expected to change over time. For example, the uptake of DER such as solar panels and battery storage is projected to increase, potentially influencing household electricity consumption patterns and reducing reliance on traditional supply. In addition, price structures may evolve due to regulatory changes, technology adoption, and shifts in wholesale energy costs.

For consumers at present there is limited ability to shop around for better export rates or tailored services, effectively limiting their choices and flexibility. Consumers would continue to have limited access to innovative offerings like dynamic pricing, demand-response programmes, or virtual power plant participation and would not be able to optimise their energy use or monetise their generation/capacity effectively under the current model/counterfactual.

The process of switching from one retailer to another will continue to require a request of change via the Code and followed through by the traders, Metering Equipment Provider (MEP) and distributor in coordination. The counterfactual scenario assumes no change to the current practice. The key features of this switching process are (and will continue to be):

- ICP-level switching only
- data requirements must follow the current Electricity Industry Participation Code (e.g., estimated "average daily consumption" during switching is codified in Part 11)
- initiation by retailer.

The operational review in 2019 found inefficiencies in this process such as delays, metering coordination issues and inconsistent timelines (Electricity Authority, 2019).

2.2.2 Factual (Revised Proposal)

> Establishing MTR as an OFF/ON switch in registry so only those that want to be MTR traders must change systems.

In this scenario, consumers can purchase electricity from one retailer and sell generation (e.g., surplus solar) to a different retailer. In other words, the Authority would adopt the Revised Proposal, enabling MTR for participating customers. This means that there will be an upgrade to the registry to flag customers that opt-in.

In the factual scenario, the multiple trading relationships is equipped with an improved switching process. The key features under this scenario are:[10]

MTR-related (Revised Proposal):

1. Consumers can have multiple retailers for the same ICP, e.g., one for import (consumption) and another for export (solar generation).
2. Registry supports split ICP functionality.

Switching-related (taking what is proposed in the Authority's consultation document):

3. New processes from traders such that they simplify systems, improve system and process efficiency, reduce manual interventions and workarounds, and reduce exceptions to manage and reduce compliance costs.
4. New processes for distributors:
    a. include a new distributor switching process that uses the registry as a central hub for transactions between the relevant participants

[10] The points below are taken from the Authority consultation paper, with some modification to the MTR-component to reflect changes under the Revised Proposal (Electricity Authority, 2025).

b. require distributors to allocate a reconciliation type in the registry to ICP identifiers, when the ICP is connected to a network extension

c. move to intra-day status changes which would require distributor events to have a time stamp for the event in addition to the date stamp

d. require distributors to record the decommissioned date in the registry as the first full day that the ICP is decommissioned (that is, the day after the physical work was performed to decommission the ICP).

5. New processes for MEPs:

    a. Allow both gaining and losing MEPs to create separate meter events on the same day, provided each event includes a timestamp.

    b. Create new fields and business rules to identify meter types and communication status at the component level, with a summary at ICP level.

    c. Permit a change of MEP participant identifier when both identifiers belong to the same MEP, without trader involvement or altering metering records.

    d. Registry manager must send MEPs notifications for: gaining trader ICP switch requests (NT), losing trader acknowledgements (AN), and switch withdrawals (AW), including both trader identifiers.

    e. MEPs must provide gaining traders access to the services interface and meter readings within specified timeframes.

    f. MEPs must supply meter readings for the switch date to both gaining and losing traders, then ongoing readings to the gaining trader.

    g. MEPs must provide traders with revised or backfilled meter readings (previously undelivered readings from metering installations).

    h. Traders must notify the registry of MEP nominations; MEPs must accept or decline by installation date. Registry auto-declines unaccepted nominations within set timeframes. Compliance included in audits.

    i. MEPs must update registry metering events for ICPs: 75 per cent within five business days of certification/activation, 100 per cent within ten business days. Compliance measured over 12 months and audited.

    j. MEPs must record removal of metering components in the registry, even if an ICP is not decommissioned.

    k. Registry automatically end-dates metering certification when an ICP is decommissioned and reinstates expiry if reversed. If equipment is removed, registry notifies MEP.

For consumers with DER, such as rooftop solar and battery storage, there are clear incentives to offer excess electricity generated or stored energy during peak periods.

For instance, a household with solar panels and a battery could maintain its primary retail contract for everyday electricity needs while entering a separate agreement with an aggregator or energy trader to manage its battery. Through time-of-use pricing and demand response programmes, the likes of an aggregator can discharge stored energy when wholesale prices are high or when the grid is under stress, generating additional revenue for the consumer (Reeve et al., 2021).

By enabling these multiple relationships, MTR lowers barriers for consumers to participate in diverse markets, making DER investments more attractive. Consumers can maximize returns without being locked into a single retailer's offerings, while the system benefits from improved peak management and reduced reliance on costly infrastructure upgrades.

The factual is expected to involve more choice and empowerment for consumers, especially those with DER (e.g., solar and batteries at home) as well as efficiencies in the switching processes.

3. Cost analysis

We treat the MTR and switching proposals separately for the cost analysis. It is understood that some of the costs would be incurred across both proposals, but it is helpful to look at them separately given how the consultation paper was constructed and responded to (and the different basis for benefits considered in the next section).

3.1 MTR will involve a level of costs across stakeholders

We consider the costs of the following parties: the Authority, retailers, MEPs and distributors. There may be some costs (measured in the value of time) that arise for consumers in searching and comparing contracts, but we would expect these to be relatively trivial over the period of analysis. For engaged consumers, the ones who are motivated to structure their consumption to reduce their net costs, the proposal may even lead to cost reductions as they hand over management of their generation resources to other parties.

Our analysis assumes that consumers have already decided to install capital equipment, and that MTR are viewed as a means of maximising returns on these investments.

The Authority is expected to incur total costs of approximately $450,000 for both the MTR and switching proposals, with each proposal assumed to cost $225,000. Retailer costs under the Revised Proposal will depend on their level of engagement with customers wishing to have MTR. We estimate one-off costs of $500,000 for four large retailers, with a remaining allowance of $1 million for other retailers, along with ongoing billing management expenses. We note that there is a possibility that some of the costs may be incurred as operating expenditure instead, and that some smaller retailers may choose not to engage.

MEPs are expected to incur costs of $1.76 million per large provider, or $7.04 million in total, based on submissions. Distributors, 26 in total, are assumed to incur one-off costs of $500,000 each to build targeted modules, based on guidance from the Authority regarding their understanding of the complexity the changes required.

We have assumed that these costs are one-off system upgrades and do not involve an ongoing component except for higher billing management costs for retailers which will depend on the uptake of MTR type arrangements for consumers.

Finally, we have included a sensitivity analysis to account for the possibility of higher costs. These costs are informed by submissions to the Authority on its original proposal and discussions with the Authority in relation to changes under Revised Proposal. A full list of assumptions and their basis is provided in Appendix A.

In total, the present value of costs for the MTR proposal is expected to amount to $25.4 million in our central estimate.

3.2 Switching costs

The implementation of the switching proposals will involve system upgrade costs for the Authority, retailers, MEPs, and distributors.

As outlined in the previous section, the Authority's share of these costs is estimated at approximately $225,000. Retailer costs are projected to be around $6 million in total, based on per-ICP cost estimates provided by two submitters. MEPs are expected to incur costs of approximately $5.34 million in total, while distributor costs are estimated at $1.3 million in total.

In total, the costs to implement the switching proposals are expected to amount to $12.7 million in our central estimate.

4. Benefit analysis

We separately set out the benefits from MTR and switching components of the proposal below, consistent with the costs section above and original consultation paper.

4.1 MTR benefits

In considering benefits we focus on changes to the way that electricity flows are incentivised and therefore change across the network, and we exclude transfers in costs/benefits from one party to another. This is consistent with the Treasury's guidance on cost-benefit analysis to focus on the real resources use.

We have excluded domestic solar installations (in the form of increased uptake or changes to the way that solar is tariffed) from our analysis given it appears the system-wide benefits are most clearly evidenced from the use of batteries (which could be coupled with solar but do not necessarily need to be for the system-wider benefits estimated).[11]

Further, we have not included the benefits of increased EV uptake. The potential of EVs to serve as battery or energy storage system provides the ability to increase the financial return from investment, for example bi-directional charging like Vehicle to Grid or Vehicle to Home. This would be considered at a later stage of MTR development when any specific changes to support this would be proposed and assessed.

The key system-level advantage of MTR arrangements would be to incentivise the use of batteries. Batteries can be optimised within the current arrangements to react to incentives to reduce system peaks and to offset high-cost peaking generation. Under the current arrangements a customer is generally incentivised to store surplus solar power for use during peak periods based on prices that remain fixed throughout the year. However, a more sophisticated aggregator would seek to arbitrage wholesale electricity prices and respond to broader price signals by charging the battery at times when prices are low. This sort of engagement, while not necessarily beyond the abilities of a savvy consumer, may not be best use of such a consumer's time/always practical, meaning handing over control to another party may be beneficial. We expect that the role of the aggregator would make it more likely that peaking benefits would be achieved. We cannot predict whether new aggregators, existing retailers or others will lead the market in offering battery management services, but there

[11] In reaching this conclusion we have considered several factors. First, it is not clear that a separately tariffed solar installation with, for example, a peer-to-peer arrangement automatically achieves a lower cost outcome system-wide. At present retail customers with solar are incentivised to shift load to the periods when solar is produced. It is not clear to us that we can necessarily assume that an alternative pricing arrangement would achieve a better outcome, although it may lead to some transfers among consumers. Second, solar uptake is already on a strong upwards trajectory that may, over time, depress the price available for injection of surplus solar energy. The business case for separating generation and load will not necessarily be improved in an MTR-type scenario. Third, there are already sophisticated tariff structures available for residential solar customers that use the interaction of solar and load to attract consumers. We do not consider other types of generation (e.g. wind) as these are not expected to make any material impact over the period of analysis.

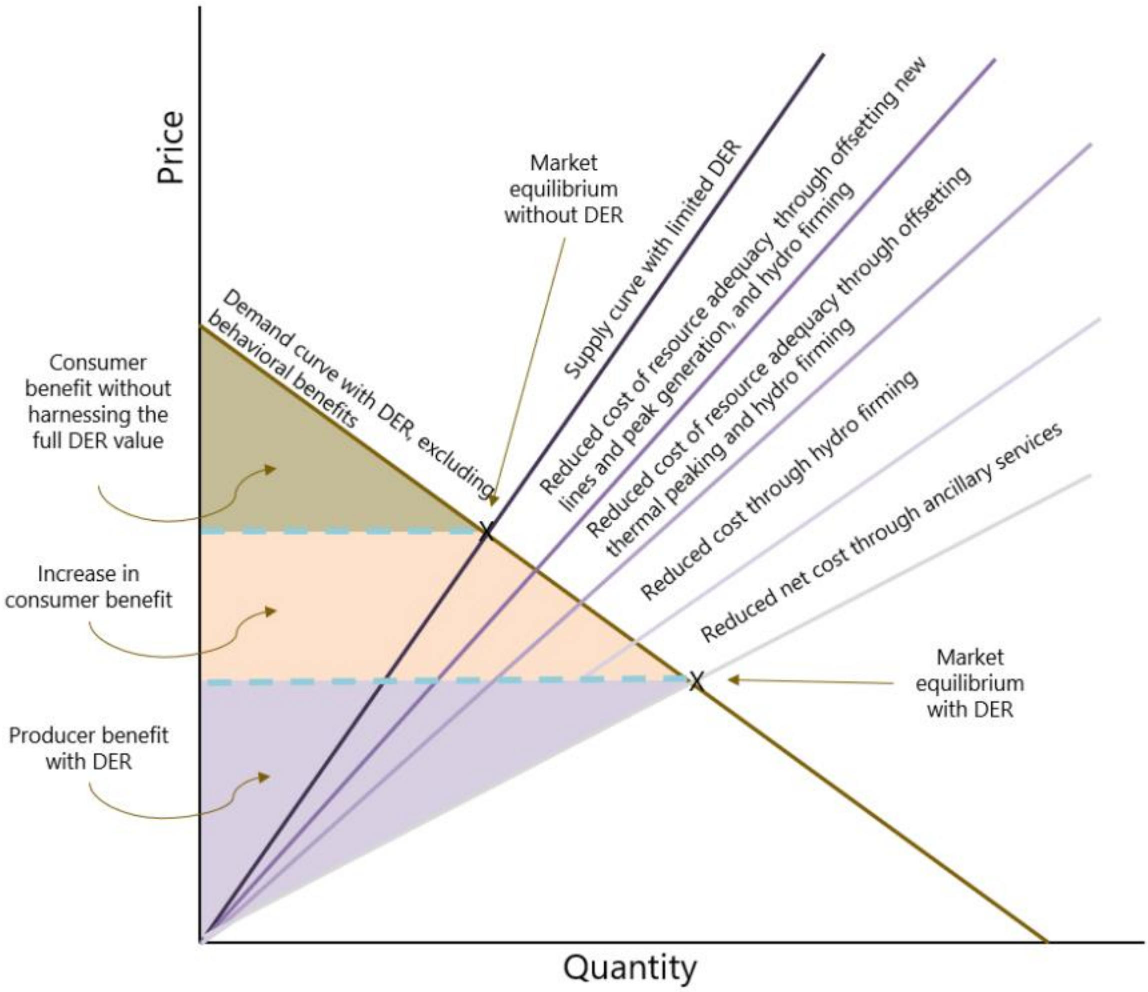
would be economic efficiencies possible from this occurring (though there are other channels through which MTR may support greater use of batteries to achieve peaking benefits), and we expect that together with other changes being made, there should be some level of competition to attract the existing and planned battery capacity to this end.

We note that the current MTR proposal (Revised Proposal) does not extend to load management services. However, we emphasise that a very similar case for batteries can be made for load management. A successful deployment of MTR may have second order benefits in easing the path to considering this as well. We have also not considered whether further uptake of batteries may eventuate (we conservatively look solely at the capacity that may be made available from existing forecasts, noting any further uptake may provide additional benefits but levels would be difficult to estimate). We accept that current forecasts may have internalised developments such as MTR.[12]

One of the most significant benefits is improved energy system efficiency. High DER uptake reduces reliance on costly centralised peaking generation and transmission infrastructure. Through MTR, consumers can trade energy more flexibly, allowing local generation and storage to meet demand and defer more expensive network upgrades. This leads to a more efficient allocation of resources and lowers overall system costs, benefiting both consumers and the wider electricity system. The figure below illustrates these efficiency gains, showing how DER integration under MTR reduces system costs compared to traditional approaches (Reeve et al., 2021).

[12] Nonetheless, we note that even if stakeholders have factored this into their decision-making without the change the benefits that depend on this occurring would not materialise, so they are still a benefit of the proposal.

Figure 1: Illustration of total economic surplus where DER is fully harnessed



Source: (Reeve et al., 2021).

This figure demonstrates that DER adoption lowers overall system costs by reducing supply-side expenses (through hydro firming, and peak offsetting) and increases consumer surplus. It supports the argument that enabling MTR, and subsequent increases in DER integration, creates economic benefits for both consumers and producers.

There are other potential benefits of batteries for instantaneous reserve and voltage management, but we have not considered these in our analysis.

4.1.1 Offset thermal peaking

Thermal peaking is when some form of thermal generation is used for peaking purposes. In New Zealand this consists essentially of open cycle gas turbines. This type of generation is the most expensive generation when considering the input cost of the fuel.

We distinguish between thermal peaking units used occasionally for system peaks with instances where fast-starting thermal peaking is used in dry years.

Deployment of batteries has the potential to reduce the call on thermal peaking if it is charged during trading periods when the thermal peakers are not being called on and then discharged during peak periods.

The thermal peaking offset was assessed with a price of $118/kW per annum (Reeve et al., 2021).[13]

4.1.2 Offset new lines and generation (renewable peaking)

The costs of building new power (transmission and distribution) lines or generation plants is generally relatively high. More uptake of DER (solar, solar and batteries, or batteries) can help meet local demand growth without the need for (i.e. deferring) major infrastructure investment or upgrades.[14]

Building new transmission or distribution lines is one of the most expensive and time-consuming solutions for meeting growing electricity demand. In practice, this approach can be deferred by deploying DER close to load centres. By generating electricity locally, DER reduces the amount of power that needs to travel over long transmission corridors, thereby lowering congestion and thermal stress on existing infrastructure.

Offsetting new lines and generation through DER creates multiple benefits. Firstly, it reduces capital expenditure, enables faster deployment, and improves reliability for remote communities. It also supports decarbonisation goals by integrating renewable resources into the grid. For example, in regions like Northland, local solar and battery projects have been used to manage peak demand and delay the need for new transmission infrastructure and further Transpower notes the benefits this provides through its FlexPoint system stating value from avoided transmission, distribution and generation of $1.5 billion per gigawatt saved (Transpower, n.d.). This approach demonstrates how distributed solutions can deliver both economic and environmental advantages while maintaining system security. We apply the assumed (avoided) cost of building new power lines and generation as in Table 2. The offset has been valued at $241 per kW per annum (Reeve et al., 2021).

4.2 Switching benefits

The primary benefits of the switching proposals are to lower the normal operational costs of market participants and to lower the number of problematic switches that lead to additional administration costs for participants and consumers. We assume that:

- The operational costs of retailers are fully offset by operational savings in the normal course of business, although we test the actual cost saving required in the breakeven analysis. We assume also that a proportion of problematic switches will not require the same amount of effort as at present and we count these savings as benefits.

---

[13] We note that the $118/kW avoided cost was derived on the basis of an average price of $80/MWh for electricity, which is lower than the average price observed over the 2018 to 2024 period, making the avoided cost a relatively conservative assumption.

[14] This is critical for remote communities or regions like Northland or West Coast where grid expansion is particularly expensive.

- For MEPs we do not include any cost savings, which means that any costs arising will have to be offset by benefits elsewhere.
- For distributors, advice from the Authority is that the savings will be recovered from operational efficiencies.
- For consumers we estimate that there will be fewer problematic switches, with time saving counted as a benefit.

In terms of switches, we understand that there around 430,000 switches per annum. Most of these do not lead to any issue, but around 250 complaints regarding switching are escalated to Utilities Disputes out of a total of around 7,000 complaints related to electricity consumer issues. Given that there are around 105,000 complaints directly to electricity retailers, we estimate that about 4,000 of those could relate to switching issues (assuming the same proportion that go to Utilities Disputes as we do not have further information on the mix of these).

We estimate that each problematic switch causes costs to retailers and consumers of two hours. The cost for an hour of a retailer employee's time has been estimated at $110.68 (Sapere estimate, which includes employment overheads).[15] For a consumer, the cost is $35 per hour (from Treasury's CBAx model). Each problematic switch therefore has estimated costs of $291.36. In addition, we estimate the cost of each switching complaint that makes it to Utilities Disputes is $703 (based on the total budget of Utilities Disputes divided by the number of complaints, noting that certain complaints may be more expensive but without further information we use the average). We estimate that the total annual cost of dealing with problematic switches is $1.3 million. We explain in the next section the required reduction in this value to make the proposal break even.

[15] See for example (SEEK New Zealand, n.d.), which shows a salary of $100-$120k for an energy analyst—to which we have added an overhead loading and considered management time for a small proportion of escalated complaints.

5. Impact assessment and conclusion

5.1 MTR

The MTR proposal has been modified from the original consultation paper and is envisaged as a lower cost option. The costs to participants will therefore be further informed by any further feedback on this consultation draft. However, at this stage a higher cost scenario is not expected to change the breakeven point significantly.

The benefits are difficult to quantify with confidence as there is uncertainty as to how, and the extent to which, they are likely to come about (i.e. whether they emerge from the role of aggregators or from retailers modifying their tariff structures, and the extent to which currently installed and planned battery capacity would be deployed).

At present we draw on estimates that there will be around 127 megawatts (MW) in distributed battery capacity installed across New Zealand from 2026, rising to 2,500MW in 2050. Decisions to install battery capacity may have internalised the prospect of MTR-type arrangements, but it is unlikely that it is the only reason to acquire battery capacity. At present it is likely that battery owners will mostly be responding to fixed tariffs and that arbitraging the wholesale electricity price is not happening to any significant degree: batteries are probably being charged while there is a negative net load and discharged during peak pricing periods. This cycle will be more pronounced during summer when the benefits of peak shaving are less valuable to the grid.

The question we pose is what proportion of planned battery capacity would need to be deployed for the stated benefits of offsetting thermal peaking and offsetting new lines and generation to cover the costs of the MTR proposal. We undertake this analysis using sensitivities for the discount rates and over forecast periods of 15 and 25 years.

Table 3: Costs and benefits of MTR

	PV (2%)	PV (8%)
Costs		
Authority (to registry)	$220,588	$208,333
Retailers (system upgrades)	$2,941,176	$2,777,778
MEPs (system upgrades)	$6,901,961	$6,518,519
Distributors (system upgrades)	$12,745,098	$12,037,037
Retailers (billing costs)	$2,556,439	$1,225,632
Total costs	$25,365,263	$22,767,298
Benefits (assume 1% uptake, 25 years)		
Offset thermal peaking	$21,775,199	$8,653,429
Offset new lines and generation	$44,473,075	$17,673,529
Total benefits (25 years)	$66,248,274	$26,326,958
Benefits (assume 1% uptake, 15 years)		
Offset thermal peaking	$7,869,787	$4,409,277

	PV (2%)	PV (8%)
Offset new lines and generation	$16,073,039	$9,005,387
Total benefits (15 years)	$23,942,826	$13,414,664
Breakeven % uptake (revised costs)		
25 years	0.36%	0.86%
15 years	1.07%	1.77%
Breakeven % uptake (original costs)		
25 years	0.41%	0.99%
15 years	1.23%	2.04%

We estimate that, depending on the input scenarios, it would require an additional 0.36 to 1.77 per cent of existing and planned battery capacity, that would not otherwise be contributing to delaying investment in distribution and transmission lines or offsetting thermal peaking, to be utilised as a result of MTR for the MTR proposal to break even. Based on the more significant costs under the original MTR proposal (Option 1), the lower bound percentage is 0.41 per cent and the higher bound is 2.04 per cent. At first sight, these percentages appear relatively trivial, and it is not hard to see motivated battery owners responding to price incentives and enabling these benefits. However, we do note several caveats that might require higher uptakes to break even. We also note further additional possible upsides.

In Table 3, to aid interpretation of the results and consideration and different sensitivities, we illustrate that if one were to assume:

- 1 per cent of battery capacity is taken up and applied to offset the identified costs associated with peaks, over 25 years the present value of total benefits would be $26.3 million to $66.2 million
- 1 per cent of capacity is taken up, over a reduced period of 15 years, the present value of total benefits would be $13.4 million to $23.9 million.

This compares with the total quantified costs of $22.8 million to $25.4 million, meaning that in three of the four illustrations, benefits would exceed costs (other than the high discount rate and lower time horizon illustration). However, given the uncertainty of uptake, we focus on the breakeven level of battery uptake needed to offset the total quantified costs, which is between 0.36 to 1.77 per cent under the Revised Proposal.

Caveats that need to be considered in interpreting the breakeven results

First, we are treating battery capacity as a sunk cost. The argument is that battery capacity is being installed for reasons that will not already have the above benefits outlined. If, however, a significant proportion of battery capacity is being installed which would be deployed anyway then this assumption may be too strong. If battery capacity installation is contingent on accessing the stated benefits (such as through Transpower's FlexPoint system), then we would need to include the costs of battery installation. We note that the costs of batteries are going down, however, and a net benefit would still be available given sufficient deployment.

Second, there is a question of whether the stated benefits are cumulative or mutually exclusive. On balance, we think that the benefits are more likely to be cumulative as there are relatively few periods in a year of peak load. There are still many remaining trading periods where arbitraging possibilities exist which would elicit the benefit of offsetting peak thermal generation. And, in any case, the two benefits are likely to coincide.

Third, we have not included costs for retailers (or others) to develop algorithms to engage with the wholesale electricity market. We assume that sophisticated trading systems already exist and while there may be some licensing fees, perhaps for new participants, these fees would be transfers between parties without the need for new resources to be applied.

Additional potential unquantified benefits

On the other hand, we have not included EVs in the analysis or the benefits of increased solar uptake. We note that there may be additional benefits from these two sources of grid injection. We have also not included future policy development contingent on the successful deployment of MTR to generation which could then extend MTR to load management or wider options included in the original consultation paper (such as peer-to-peer trading or community sharing), which could also have significant upside.

We also note that there are potential competition benefits from additional participants (e.g. aggregators) entering the market. There is a question relating to whether the consumer surplus increases at the expense of the producer surplus. For battery capacity we are not convinced that there would necessarily be such a dynamic. That is, the benefits should lower the costs for delivery of electricity through changes in peak consumption with benefits to all consumers: in fact, both consumers and producers may benefit depending on the electrification and pricing/offering dynamics.

We note that there could be benefits in the form of additional battery uptake. However, we have not quantified these as this analysis would rely on uncertain assumptions and require offsetting the cost of batteries. We also note that the fragmentation of the market (into additional retail customers) may cause additional competition, but that this benefit would have to be weighed against any benefits of bundling.

We considered whether greater competition for solar generation output may lead to benefits for consumers at the expense of producers. However, we are not convinced of this. First, retail contracts for solar customers will be constructed on the apparent net load profile of the solar consumer. If the solar generation is separated from the load profile, then the consumption tariffs would likely change. There is also the possibility that solar customers may be less incentivised to match their load profile to the solar load profile under alternative contracting arrangements.

5.2 Switching

We present the table of costs and benefits from the switching initiatives as a breakeven analysis. We assume that retailers and distributors will cover their costs from the streamlined process (though estimate the actual costs that need to be recovered to justify the switching component alone). We also understand that the Authority will save $18,684 per annum from a reduction in manual processes.

Once these costs and cost savings have been considered there are remaining costs that need to be recovered in the break-even analysis. Looking at problematic switches and the value of time to deal with them, we estimate that the present value cost of these over the 25-year period of analysis is between $14.1 million and $25.7 million depending on the discount rate applied. We estimate that the cost of problematic switches that would have to be reduced would need to account for at least 20 per cent to 44 per cent the current problematic switches.

Table 4: Switching costs and benefits estimates

	PV (2%)	PV (8%)
Costs		
Authority (to registry)	$220,588	$208,333
Retailers (system upgrades)	$5,235,294	$4,944,444
MEPs (system upgrades)	$5,937,772	$5,607,896
Distributors (system upgrades)	$1,274,510	$1,203,704
Total costs	$12,668,164	$11,964,377
Benefits (from cost reductions in normal operations, 25 years)		
Cost reductions Authority	$364,776	$199,448
Cost reductions MEPs	$-	$-
Cost reductions retailers	$5,937,772	$5,607,896
Cost reductions distributors	$1,274,510	$1,203,704
Total benefits (from cost reductions in normal operations)	$7,577,058	$7,011,047
Net cost needing to be recovered from other activities	$5,091,106	$4,953,330
Costs of problematic switches		
Retailer costs (two hours per switch)	$16,947,364	$9,266,254
Consumer costs (two hours per switch)	$5,359,180	$2,930,221
Cost for utilities disputes	$3,428,991	$1,874,858
Total cost of problematic switches	$25,735,534	$14,071,334
Breakeven % reduction in problematic switches		
Percentage reduction in problematic switches needed (25 years)	20%	35%
Percentage reduction in problematic switches needed (15 years)	30%	44%

Further details on problematic switches

We have looked at the number of problematic switches (those that lead to complaints to retailers and then to Utilities Disputes).

We understand there are around 250 complaints that are made to Utilities Disputes out of a total of 6,694 (NZIER, 2024; Utilities Disputes Limited, 2025) complaints regarding electricity. Using the average cost of a dispute, the cost of dealing with these disputes is estimated at $176,000 per annum.

Given that there are about 105,000 complaints directly to electricity retailers (NZIER, 2024), we infer that about 4,000 of those could relate to switching. Making assumptions regarding the costs of retailers and consumers in administering and raising these complaints we estimate the annual costs of these complaints is about $870,000 for retailers and $275,000 for consumers.[16]

The present value of these costs is between $14.1 million and $25.7 million depending on the scenarios. We would not expect that the switching proposal would eliminate all these costs (and it should be assumed that retailers have already counted some of these cost savings when estimating the net impact of the arrangements on their business operations). Nonetheless, we assume that some of these costs will be reduced once the new proposals are implemented, with the breakeven levels needed to justify the costs shown above.

[16] We assume that each complaint takes about two hours of administration time for retailers and a similar period of time for consumers. Retailer time is estimated at $110.68 per hour (Sapere calculations based on industry benchmarking and including an overhead loading, for instance see (SEEK New Zealand, n.d.; World Salaries, n.d.), and consumer time at $35 per hour (CBAx).

References

AEMC. (2024, November). *AEMC finalises landmark reform to accelerate smart meter rollout*. https://www.aemc.gov.au/news-centre/media-releases/aemc-finalises-landmark-reform-accelerate-smart-meter-rollout

Australian Energy Market Commission. (2016). *National Electricity Amendment (Multiple Trading Relationships) Rule 2016—FINAL RULE DETERMINATION*. https://www.aemc.gov.au/sites/default/files/content/d37688a5-d16d-442b-80f5-e7fa51d64ab7/Multiple-Trading-Relationships-Final-Rule-Determination.pdf

CEPA. (2020). *P379 Impact Assessment*. Elexon. https://www.elexon.co.uk/bsc/documents/change/modifications/p351-p400/p379-final-cost-benefit-analysis-report/

Department for Energy Security and Net Zero. (2025). *Smart Meter Statistics in Great Britain: Quarterly Report to end March 2025*. https://assets.publishing.service.gov.uk/media/6836e571e11dd1e85b0cbaa1/Q1_2025_Smart_Meters_Statistics_Report.pdf

Electricity Authority. (n.d.). *Your power bill*. Retrieved January 20, 2026, from https://www.ea.govt.nz/your-power/bill/

Electricity Authority. (2019). *Switch process review—Issues and options*. https://www.ea.govt.nz/projects/all/evolving-multiple-trading-and-switching/consultation/switch-process-review-issues-and-options/None

Electricity Authority. (2025). *Evolving multiple retailing and switching: Consultation paper*. https://www.ea.govt.nz/documents/7385/Evolving_multiple_retailing_and_switching_-_Consultation_paper.pdf

Elexon. (n.d.). *P379 'Multiple Suppliers through Meter Splitting.'* https://www.elexon.co.uk/bsc/mod-proposal/p379/

Keen, B. (2024). Rushing to the finish line: Can we clear the hurdles on the way to 100% smart meters by 2030? *Australian Energy Council*. https://www.energycouncil.com.au/analysis/rushing-to-the-finish-line-can-we-clear-the-hurdles-on-the-way-to-100-smart-meters-by-2030/

MBIE. (2025). *Electricity cost and price monitoring*. https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring

NZIER. (2024). *Independent dispute resolution: Cost benefit analysis* [Report to Utilities Disputes Limited (UDL)]. https://www.udl.co.nz/assets/About-us/2024-Research-Reports/UDL-and-NZIER-2024-report.pdf

Reeve, D., Comendant, C., & Stevenson, T. (2020). *Distributed Energy Resources – Understanding the potential*. https://static.transpower.co.nz/public/uncontrolled_docs/Distributed%20Energy%20Resources%20-%20Understanding%20the%20potential%20-%20main%20report%20-%20final_0.pdf?VersionId=HZUkiRMgp_krcHqKKkBcaremfLVmrygI

Reeve, D., Comendant, C., & Stevenson, T. (2021, September 13). *Cost-benefit analysis of distributed energy resources in New Zealand*. https://www.ea.govt.nz/documents/1742/Sapere_CBA.pdf

SEEK New Zealand. (n.d.). *Energy Analyst salary in Wellington (January, 2026)*. Retrieved January 20, 2026, from https://www.seek.co.nz/career-advice/role/energy-analyst/salary/in-wellington

Stuff. (2025). *Your power bill average*. https://www.stuff.co.nz/money/360669330/your-power-bill-average

Styles, R. (2022). Smart meters: What are the pros and cons? *Consumer*. https://www.consumer.org.nz/articles/smart-meter-pros-and-cons

Transpower. (n.d.). *FlexPoint*. Retrieved January 20, 2026, from https://www.transpower.co.nz/our-work/distributed-energy-resources/flexpoint

Utilities Disputes Limited. (2025, May 15). *Re: Improving Retail Service Quality: Switching* [Submission to the Commerce Commission on its discussion paer "Improving Retail Service Quality: Switching (Switching Issues paper)"]. https://www.udl.co.nz/assets/Submissions/UDL-Improving-Retail-Service-Quality-Switch-15-May-2025.pdf

Watson, N. E. (2022). *Future energy retail markets: Stakeholder views on multiple electricity supplier models in the UK*. University College London. https://discovery.ucl.ac.uk/id/eprint/10157015/2/Watson_ECEEE%20paper%20draft%202%20(word%20cut).pdf

World Salaries. (n.d.). *Average Energy Analyst Salary in Auckland, New Zealand for 2026*. World Salaries. Retrieved January 20, 2026, from https://worldsalaries.com/average-energy-analyst-salary-in-auckland/new-zealand/

Appendix A Assumptions used in our analysis

The tables below set out the core assumptions underpinning the CBA, looking at MTR and switching CBA assumptions in turn.

Table 5: MTR CBA Assumptions

Variable	Assumptions
Capacity forecast of installed batteries (MW)	We use the uptake of batteries following Transpower's Whakamana I Te Mauri Hiko.
Avoided cost of thermal peaking (capacity value)	This value represents the annual cost per kW of operating thermal peaking generation that could be avoided. We use $118/ kW per annum (Reeve et al., 2021).
Avoided cost of providing new capacity	This value represents the annual cost per kW of building new infrastructure investment through alternatives like DERs. We use $241/kW per annum (Reeve et al., 2021).
Average size of residential batteries	We assume 13.5 kW residential batteries are installed at one ICP.
Percentage of customers who engage in MTR	We assume 1% take-up in the new policy and then test the sensitivity or breakeven level of take-up required to offset identified costs.
Percentage of billing cost (% of bill)	We assume 13% of an electricity bill contributes to the costs of generating the bills (Stuff, 2025), noting the Authority's estimate of retail costs are similar to this as well (Electricity Authority, n.d.).
Average annual residential electricity bill (excludes GST)	We assume $2,240 of annual cost on average (MBIE, 2025).
Costs: policy implementation, system upgrades and billing costs	We assume costs are primarily derived from submissions shared by the Authority and/or the Authority's estimates, adjusting informed by discussions with the Authority where appropriate for changes to the proposal under the Revised Proposal.

Table 6: Switching CBA Assumptions

Variable	Assumptions
Cost reductions (from normal course of business)	We assume the benefits of the switching proposal come from the avoided cost from the status quo. We assume cost reduction from the Authority of $18,684 per annum.
Switching costs	We assume costs come incurred by the Authority, MEPs, retailers and distributors (again picking up on any clarifications from the Authority's subsequent engagement with industry). We identify costs to specific parties: • MEPs from the Intellihub submissions which identified the switching costs coupled with synergies from having MTR – on average, they estimated the upfront cost to be $5.3 million. • Retailers' submissions mainly from Contact and Mercury – on average, we estimate the upfront cost of $6 million. • Distributors occur costs of up to $1.3 million. The Authority costs are allocated by splitting the total cost evenly between the MTR and switching proposals.

Appendix B Further detail in relation to feedback received in the UK

The consultation responses to Elexon's proposed P379[17] modification demonstrated broad industry concern about the scale and cost of enabling multiple suppliers to serve a single boundary meter. Submitters largely agreed that although the concept of allowing split metering had merit, the practical implementation would involve significant costs. Many respondents described the proposal as requiring "large and complex industry change", pointing to the degree of redesign needed across settlement systems, data flows, registration services, and supplier operations. These concerns appeared consistently across supplier submissions and aligned strongly with CEPA's conclusions that the implementation costs were far higher than initially expected.

Suppliers emphasised that P379 would require major redevelopment of core IT systems, including billing, customer account management, forecasting, hedging, and market notification platforms. Several submissions indicated that these were not incremental modifications but fundamental structural changes.[18] Additionally, agents such as IMServ, SMS plc, and Siemens noted that new data handling and aggregation processes would require extensive redesign, raising settlement risk and driving up assurance and operational costs.

Distribution Network Operators (DNOs) also expressed cost concerns, particularly around the impacts on data flows and network-side systems. They cautioned that enabling multiple suppliers at a single meter point would require redesigning existing processes that currently assume a single supplier. Submissions from DNOs such as BUUK Infrastructure, Northern Powergrid, and SP Energy Networks highlighted that network charging, metering, and registration interactions would all need to change, increasing operational and compliance costs. Although no numeric figures were provided, respondents described these changes as "non-trivial" and "resource intensive," reinforcing the overall view that P379's implementation costs were systemic and widespread.

Other organisations, including BT, SECAS, and energy market consultants, raised concerns about associated smart metering and data security costs, noting that new data exchange mechanisms and governance processes (particularly around the proposed Customer Notification Agent role) would require extensive Smart Energy Code and Balance and Settlement Code (BSC) amendments. These amendments would introduce both technical and administrative burdens, with cost implications for every market participant interacting with settlement or smart metering data. Respondents also noted that the need for a new market role would itself generate new infrastructure, data validation mechanisms, and compliance frameworks, further contributing to the overall cost challenge.

Consultation submissions for P379 came from a broad mix of GB Energy market participants. A large portion of submissions came from licensed electricity suppliers, including Centrica, Drax (Opus and Haven Power), Octopus Energy, OVO Energy, SSE Energy Supply, and Utilita Energy, reflecting their

[17] Note that P379 proposal discussed in here are different to what the Authority has proposed. As explained in the main report, the P379 proposed a more complex split metering system.

[18] Respondents did not disclose numerical cost figures publicly (as these were redacted in the CEPA impact assessment).

central role in retail market operations; these suppliers highlighted the extensive system redevelopment the modification would require as echoed by the other participants.

Collectively, the submissions made clear that P379's cost burden extended beyond direct financial expenditure. CEPA's Impact Assessment echoed this by highlighting the opportunity cost associated with implementing P379, in particular, that the industry's resources and expertise would be diverted from more urgent Net Zero-critical programmes. CEPA noted that this diversion had a material "cost" of its own, as it could slow progress on priority reforms. Together, these financial, structural, and opportunity-based costs created a profile of burdens that significantly outweighed the potential benefits identified for electric vehicles, heat-as-a-service models, or community energy participation.

The decision to withdraw P379 proposal mentioned the rationale that some of the desired outcomes are already covered under BSC Modifications P375 'Metering behind the Boundary Point', P376 'Utilising a Baselining Methodology to set Physical Notifications' and P415 'Facilitating access to wholesale markets for flexibility dispatched by Virtual Lead Parties', and hence given the very high cost of implementing P379, the added value cannot be justified (Elexon, n.d.).

About Sapere

Sapere is one of the largest expert consulting firms in Australasia, and a leader in the provision of independent economic, forensic accounting and public policy services. We provide independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

'Sapere' comes from Latin (to be wise) and the phrase 'sapere aude' (dare to be wise). The phrase is associated with German philosopher Immanuel Kant, who promoted the use of reason as a tool of thought; an approach that underpins all Sapere's practice groups.

We build and maintain effective relationships as demonstrated by the volume of repeat work. Many of our experts have held leadership and senior management positions and are experienced in navigating complex relationships in government, industry, and academic settings.

We adopt a collaborative approach to our work and routinely partner with specialist firms in other fields, such as social research, IT design and architecture, and survey design. This enables us to deliver a comprehensive product and to ensure value for money.

For more information, please contact:

Angus White

Phone: +64 21 130 2174

Mobile: +64 21 130 2174

Email: awhite@thinkSapere.com

Wellington	Auckland	Melbourne	Sydney	Canberra	Perth	Brisbane
Level 9 1 Willeston Street PO Box 587 Wellington 6140	Level 20 151 Queen Street PO Box 2475 Shortland Street Auckland 1140	Level 11 80 Collins Street Melbourne VIC 3000	Level 18 135 King Street Sydney NSW 2000	GPO Box 252 Canberra City ACT 2601	PO Box 1210 Booragoon WA 6954	Level 18 324 Queen Street Brisbane QLD 4000
+64 4 915 7590	+64 9 909 5810	+61 3 9005 1454	+61 2 9234 0200	+61 2 6100 6363	+61 8 6186 1410	+61 7 2113 4080

www.thinkSapere.com

independence, integrity and objectivity