Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Final Cost-Benefit Analysis

Final Report

Prepared by Energeia for the
Australian Energy Market Commission

15 August 2024

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Executive Summary

Background

In May 2022, the Australian Energy Market Operator (AEMO) submitted a rule change request to the Australian Energy Market Commission (AEMC), entitled Flexible Trading Arrangements (Model 2) and Minor Energy Flow Metering in the National Electricity Market (NEM). The rule change request proposed enabling consumers to have their consumer energy resources (CER) separately identified and treated independently in market settlement – to help unlock the value of CER. It also proposed introducing flexible metering arrangements to make it easier to meter CER and other technology such as streetlights.

This report is designed to inform the AEMC's consideration of AEMO's rule change request. The purpose of this report is to communicate the results of Energeia's research, analysis and modelling of the impacts, costs, and benefits of a range of policy scenarios related to allowing a secondary settlement point (SSP) to enable greater CER flexibility. This report also provides an analysis of future directions for the AEMC to consider, which target policy scenarios that maximise the potential value from CER flexibility.

In December 2022, the AEMC published a consultation paper identifying key issues for feedback. In August 2023, the AEMC published a Direction Paper responding to stakeholder feedback and outlining further models and issues for consideration. In February 2024, the AEMC published Energeia's CBA Report[1] alongside its Draft Determination. This report provides an updated CBA based on our consideration of stakeholder feedback, discussions with the AEMC, and additional research, analysis, and modelling. This report also provides an analysis of future directions for the AEMC to consider, which target policy scenarios that maximise the potential value of CER flexibility.

Scope and Approach

The analysis outlined in Energeia's Methodology Report[2], consistent with the AEMC's Directions Paper, fell under two phases of objectives:

- **Phase A** – to determine the incremental value of the most promising CER load flexibility options in terms of benefits to the electricity system and to consumers, considering an expected sharing of benefits across supply chain participants, and
- **Phase B** – to determine the economic impacts, costs, and benefits of proposed rule changes on the system and the required threshold of incremental uptake to ensure that this rule change is viable for market participants and consumers.

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[1] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources: DRAFT Cost-Benefit Analysis (2024), https://www.aemc.gov.au/sites/default/files/2024-02/Energeia%20report%20_%E2%80%98Benefit%20Analysis%20of%20Load%20Flexibility%20from%20Consumer%20Energy%20Resources%20Draft%20Cost-Benefit%20Analysis%E2%80%99..pdf

[2] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Methodology Report (2023), https://www.aemc.gov.au/sites/default/files/2023-08/CER%20Flexibility%20Modelling%20Methodology%20Paper%20-%20FINAL.pdf

This report covers the Phase B scope.

Energeia worked closely with the AEMC to update the key inputs and scenarios in response to stakeholder feedback, and to develop a revised CBA for the AEMC to consider as part of its Final Determination. The stages of this update are outlined below:

- **Review and Undertake Stakeholder Engagement** – Energeia reviewed stakeholder feedback in response to the Draft Determination and attended targeted stakeholder engagement with the AEMC and key stakeholder groups.
- **Revise Inputs and Assumptions** – Energeia updated and validated additional inputs used in the revised CBA. Inputs were updated in response to stakeholder feedback or were revised inputs provided directly from stakeholders.
- **Define Rule Change Policy Options** – Energeia worked closely with the AEMC to develop the revised scenarios to be tested. Updates to the scenarios were made in response to stakeholder feedback.
- **Analyse Rule Change Impacts** – Energeia estimated the economic costs and benefits of each updated rule change option via the same case study methodology used previously and estimated the level of uptake needed for the scenario to break even at a system-wide level.
- **Develop Recommendations** – Energeia developed updated recommendations based on the findings of the CBA.

Phase A analysis is not included in this report, and the Phase A workstream outcomes will be published independently of the Final Determination.

We have developed a separate report that focuses on the costs and benefits associated with Workstream 3 of the rule change (measuring energy flows using in-built technology) associated with streetlights and public EV chargers.[3]

Value of the Rule Change (Phase B)

Phase B involved an analysis of the economic impacts, costs, and benefits of the proposed rule change on the system, including the:

- potential rule change scenarios,
- adoption required to break even on the estimated costs of the rule change, and
- the potential value of removing the key policy and regulatory barriers that would remain.

Throughout the analysis, Energeia, the AEMC and stakeholders noted several benefits not quantified in our CBA that would be expected to arise from this rule change and should be recognised qualitatively. These include:

- Increased certainty for large customers
- Avoided costs of setting up an embedded network
- Increased competition
- Reduced transaction costs
- Increased visibility for networks

[3] AEMC, Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis – Draft Report (2023), https://www.aemc.gov.au/sites/default/files/2024-02/Energeia%20Draft%20Report-%20Measuring%20Energy%20Flows%20from%20In-Built%20Technology%20%28Streetlights%2C%20EV%20Chargers%2C%20Other%20Street%20Furniture%29%20Analy.pdf

Energeia worked with the AEMC to update the policy scenarios, inputs and assumptions, and CBA analysis, from stakeholder feedback received and additional investigation of the key issues raised.

Summary of the Key Feedback Received and Our Response

Energeia has incorporated the key feedback into the CBA as revised inputs and scenarios where it could be substantiated. Stakeholder feedback on our CBA Report is summarised into four key addressable areas:

- DNSPs suggested limited benefits of inbuilt revenue metering NMI allocation on network visibility
- DNSPs noted that networks do not need revenue-grade metering for contracting network services
- DNSPs provided cost inputs for system upgrades to manage a secondary NMI
- Stakeholders commented on the need for recognition of the value of related rule changes when considering a rule change with a significant inter-relationship with other rule changes

A full summary of stakeholder feedback with Energeia's responses can be found in Appendix A: Feedback Received on Draft Determination.

Revised Rule Change Scenarios

Energeia developed revised economic case study scenarios in response to the stakeholder feedback and in consultation with the AEMC. These revised scenarios cover proposals for large and small customers and are detailed in Table E1 below:

- **Base Case**: This scenario assumes that NMI service providers will perform the role of allocating NMIs and maintaining standing data at SSP NMIs and need to undertake system upgrades to perform this role.
- **Base Case with DNSP NMI Allocation**: This scenario assumes that DNSPs will perform the role of allocating NMIs and maintaining standing data at SSP NMIs.
- **Best Case, without Additional Reforms**: This scenario assumes that NMI service providers will perform the role of allocating NMIs and maintaining standing data at SSP NMIs, along with lower system upgrade costs for AEMO and greater benefits for the avoidable cost of metering.
- **Best Case with IPRR and Cost Reflective Pricing[4]**: This assumes the Base Case but includes benefits from CRP and IPRR reforms. This assumes system upgrades from the DNSP to provide cost-reflective network pricing to the SSP.

Energeia notes that realising CRP and IPRR benefits requires additional reforms, so this rule change is an incremental change that would reduce some barriers to other reforms being developed to capture these benefits.

Table E1 outlines how these scenarios have been applied in the CBA compared to the CBA Report.

[4] Energeia acknowledges that dynamic prices to devices would cost more to implement.

Table E1 – Final Rule Change Scenarios by CBA Element

Benefit /Cost	CBA Element	CBA Draft Position	Scenarios				Explanation
			Base Case	**Base Case with DNSP NMI Allocation**	**Best Case, without Additional Reforms**	**Best Case with IPRR and Cost Reflective Pricing**	
Benefit	Avoidable Small Customer[1] Type-4 Metering Costs for Network Services	$16.38 / device / year	25% avoidable	25% avoidable	75% avoidable	25% avoidable	This reflects that networks don't use metering for thermal relief network services (e.g. asset investment deferral) in many cases. Additionally, the cost of pattern-approved in-device metering is not zero. However, the secondary tariff-based controlled load is the largest demand response (DR) resource in Australia.
	Cost Reflective Network and Retailer Pricing	Excluded from Rule Change	Excluded	Excluded	Excluded	Included	This reflects that networks having access to revenue-grade metering data at secondary points should make it easier to offer cost-reflective prices for flexible devices, including location-based, real-time pricing. However, this does not guarantee customers will take it up.
	Societal Benefits of FRMPs Participating in Dispatch through IPRR	Not Considered	Excluded	Excluded	Excluded	Included	This reflects the rule change inducing further uptake of IPRR, reducing instances of errors in demand forecasts, leading to lower wholesale prices and frequency control ancillary services (FCAS) requirements.
Cost	System Upgrade Costs (Incurred by DNSPs)	Negligible	-	$1.71 / device / year[2]	-	$1.71 / device / year[2]	This reflects feedback from networks that performing the role of NMI allocation for secondary points would require costly system upgrades. These are required to establish a hierarchy in their systems to receive NMI standing data and to manage interactions with AEMO's market settlement and transfer solution (MSATS). The NMI service provider option reflects costs associated with the alternative scenario of NMI allocation at secondary points to be managed by an accredited NMI service provider instead of DNSPs.
	System Upgrade Costs (Incurred by NMI Service Providers)		$0.99 / device / year[3]	-	$0.99 / device / year[3]	$0.99 / device / year[3]	
	NMI Allocation Costs (Incurred by DNSPs)	$8.42 / device / year Incurred by DNSPs	-	$8.42 / device / year	-	-	
	NMI Allocation Costs (Incurred by NMI Service Providers)		$2.81 / device / year[4]	-	$2.81 / device / year[4]	$2.81 / device / year[4]	
	AEMO and Retailer System Upgrade Costs	$0.49 / device / year / system	Align with DER Integration Program Costs ($0.49 / device / year / system)	Align with DER Integration Program Costs ($0.49 / device / year / system)	50% lower ($0.25 / device/year / system)	Align with DER Integration Program Costs ($0.49 / device / year / system)	Reflects feedback that AEMO and retailer systems are already able to support activities proposed in the rule change. Sensitivity is due to uncertainty in the cost of this upgrade, rather than any functional variation.

Source: Energeia

[1] The $16.38/customer has been maintained for large customers.

[2] Derived from average value in system upgrade costs received from networks.

[3] Derived from the lowest value in system upgrade costs received from networks.

[4] Derived from the advice from embedded network managers and metering coordinators.

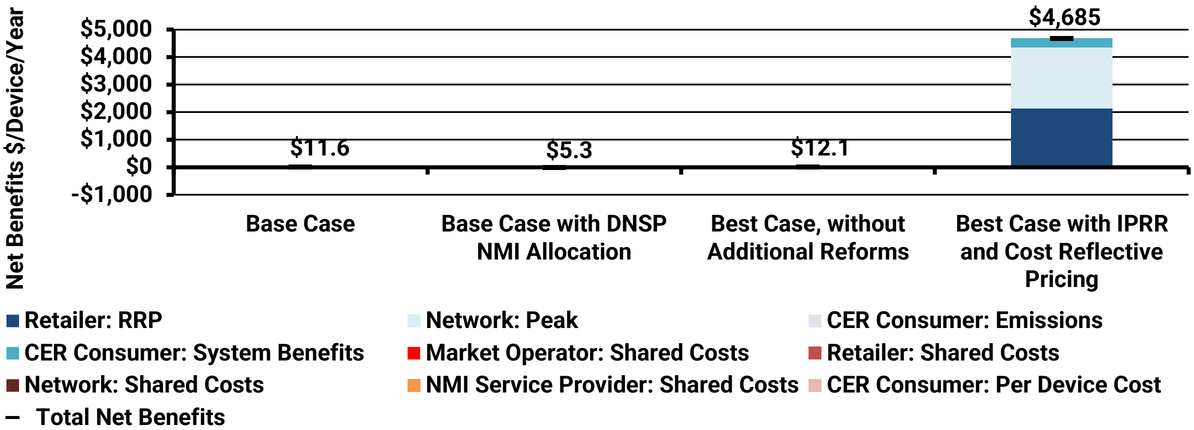
Rule Change Impact Assessment

Energeia's revised impact analysis, which is presented below, identified and modelled the key costs and benefits of each rule change scenario relative to the baseline of the status quo for small and large customers. Energeia also updated our calculation of the breakeven point where flexible CER uptake makes each rule change cost economic for customers.

Large Customers

Figure E1 and Table E2 report Energeia's estimate of the net benefits of each scenario against the status quo for large customers with batteries. The results show that under all scenarios, there is a net benefit vs. the status quo (i.e., the embedded network framework).

Figure E1 – Large Customer Battery Net Benefits Against Status Quo



Source: Energeia Modelling

Table E2 – Summary of Large Customer Battery Net Benefits Against Status Quo

	Net Benefits ($/Year/Device)									
Scenario	Retailer	Network	CER Consumer		Market Operator	Retailer	Network	NMI Service Provider	CER Consumer	Total
Name	RRP	Peak	Emissions	System Benefits	Shared Costs	Shared Costs	Shared Costs	Shared Costs	Per Device Cost	Net Benefits
Base Case	-	-	-	-	-$0.49	-$0.49	-	-$0.99	$13.57	$11.60
Base Case with DNSP NMI Allocation	-	-	-	-	-$0.49	-$0.49	-$1.71	-	$7.95	$5.26
Best Case, without Additional Reforms	-	-	-	-	-$0.25	-$0.25	-	-$0.99	$13.57	$12.09
Best Case with IPRR and Cost Reflective Pricing	$2,144	$2,199	-$6.28	$337	-$0.49	-$0.49	-$1.71	-$0.99	$13.57	$4,685

Source: Energeia Modelling

In all modelled scenarios, the proposed rule change benefits consistently show reduced costs per customer against the status quo by avoiding the requirement for a second meter through the approval of lower-cost inbuilt metering.

The Base Case scenario delivers $11.60 per year per device in net benefits. This scenario's benefits are due to assuming that metering coordinators will assume the NMI allocation and management role.

The lowest net benefit is under the Base Case with DNSP NMI Allocation scenario, which delivers $5.26 in net benefits per device per year. These benefits are mainly due to the avoided cost of installing secondary metering on the site through recognition of inbuilt device metering. However, they are offset by the higher NMI allocation and management costs assumed for DNSPs.

The Best Case, without Additional Reforms scenario, large devices deliver $12.09 per device per year. This scenario additionally assumes that metering coordinators will assume the NMI allocation and management role. This scenario only differs from the Base Case due to a 50% lower assumed system upgrade cost for both AEMO and retailers.

The Best Case with IPRR and Cost Reflective Pricing scenario delivers the highest net benefit at $4,685 per device per year. This scenario's higher net benefit is driven by the assumed avoided retailer RPP and DNSP peak costs as a result of applying more efficient tariffs. This scenario has marginally higher upfront costs than the Base Case due to the assumed DNSP system upgrades required to provide cost-reflective network pricing to a secondary settlement point.

Note, a small magnitude of negative emissions benefits may occur in the cost-reflective pricing modelling as optimising for economic benefits under cost-reflective pricing settings sometimes results in a customer deviating from the default modelled behaviour of charging during solar hours and opting to provide wholesale or network services. Energeia's modelling did not directly optimise to minimise grid emissions.

It is important to acknowledge that these benefits depend upon the CRP and IRRP rule changes and their related mechanisms.

1. Secondary settlement points can enable CRP to be sent to the CER device, which in turn unlocks more optimal flexible operation of CER and associated benefits.
2. The related IPRR benefits assumed are accrued through reducing inefficiencies from demand forecast errors captured under the system benefits.

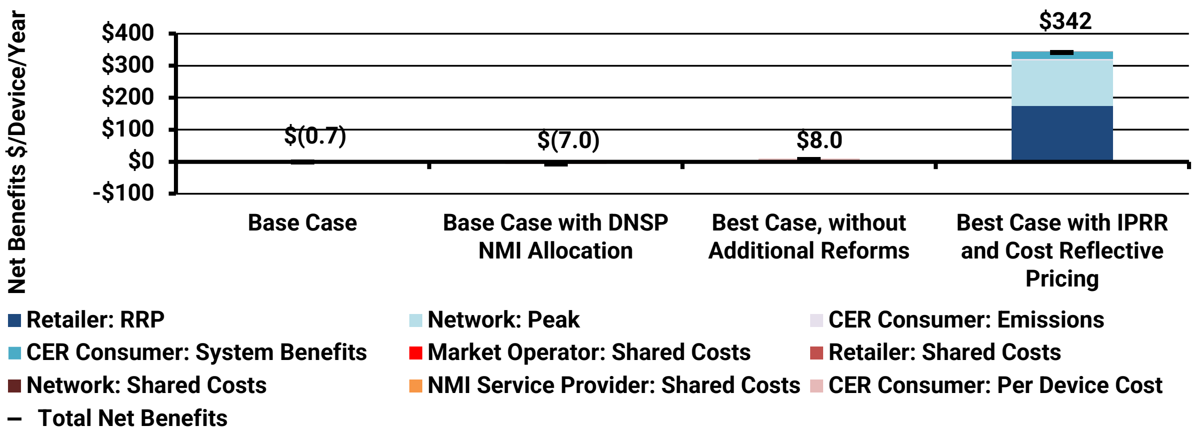
Energeia notes that realising CRP and IPRR benefits requires additional reforms, so this rule change is an incremental change that helps to reduce some barriers for other reforms being developed to capture these benefits.

Small Customers

In contrast to the large customers, while the small customer CBA shows the Best Case, without Additional Reforms and the Best Case with IPRR and Cost Reflective Pricing scenarios delivering a net positive benefit, the Base Case with DNSP NMI Allocation and Base Case scenarios result in a net negative benefit.

The result of the small customer battery CBA is shown in Figures E2 and Table E3 below.

Figure E2 – Small Customer Battery Benefits Against Status Quo



Source: Energeia Modelling

Table E3 – Summary of Small Customer Battery Net Benefits Against Status Quo

Scenario Name	Retailer RRP	Network Peak	CER Consumer Emissions	CER Consumer System Benefits	Market Operator Shared Costs	Retailer Shared Costs	Network Shared Costs	NMI Service Provider Shared Costs	CER Consumer Per Device Cost	Total Net Benefits
	Net Benefits ($/Year/Device)									
Base Case	-	-	-	-	-$0.49	-$0.49	-	-$0.99	$1.29	-$0.68
Base Case with DNSP NMI Allocation	-	-	-	-	-$0.49	-$0.49	-$1.71	-	-$4.33	-$7.02
Best Case, without Additional Reforms	-	-	-	-	-$0.25	-$0.25	-	-$0.99	$9.47	$8.00
Best Case with IPRR and Cost Reflective Pricing	$175	$141	$5.66	$22.48	-$0.49	-$0.49	-$1.71	-$0.99	$1.29	$342

Source: Energeia Modelling

In all modelled scenarios, the policy benefits of avoided metering are lower for small customers due to reduced avoided metering benefits based on stakeholder feedback. As a result, not all options tested for small customers result in net benefits in the CBA.

The Base Case scenario delivers a net negative CBA of $0.68 per device per year. This scenario's relatively low costs from NMI service provider-led NMI allocation and management are still larger than the avoidable metering benefits.

The results show a net negative of $7.02 per device per year under the Base Case with DNSP NMI Allocation scenario. This outcome is lower than the Base Case due to the higher cost assumption of DNSP-led NMI allocation and management.

The Best Case, without Additional Reforms scenario is the first small customer scenario with a net positive CBA delivering $8.00 per device per year. This is mainly due to the lower assumed market operator and retailer costs, and higher assumed avoided metering benefits as well as NMI service provider-led NMI allocation and management.

As is the case for the large customer case study, the highest net benefits are seen under the Best Case with IPRR and Cost Reflective Pricing scenario at $342 per device per year. This scenario assumes the same benefits from the CRP and IRRP rule changes per kWh of CER as described under the large customer case study results.

Breakeven Analysis

Energeia used breakeven analysis to identify the level of CER flexibility participation required for the benefits of each CBA scenario to match the costs. If the uptake of CER flexibility via a second NMI were to exceed these levels, the rule change would produce a net benefit. AEMO's 'Consensus' flexible CER uptake scenario is shown alongside as a benchmark.

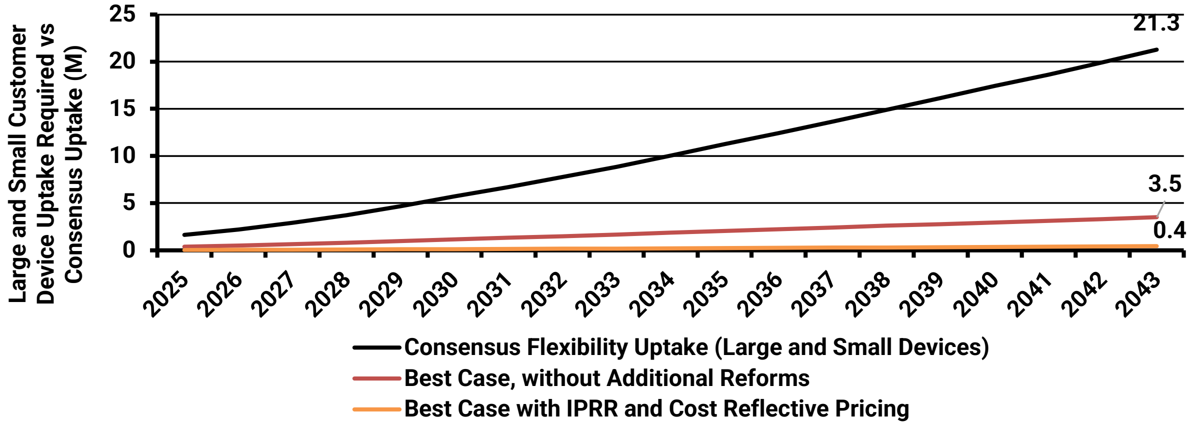
Energeia notes that our breakeven analysis excludes consideration of second-order benefits, nor does it include benefits from reduced barriers to entry, including greater choice, lower prices, and more innovation.

The breakeven analysis only shows a positive business case when both small and large customers have a net benefit CBA in the case studies shown above. The two scenarios with small and large customer net-positive CBA outcomes are shown in Figure E3 below, assuming proportional uptake.

Under the Best Case, without Additional Reforms scenario, both large and small customers are considered as both see a positive net benefit under this policy option. An additional 184k devices per year, or 16% of all AEMO forecast flexible CER devices, would need to be enrolled in CER flexibility services to break even, totalling 3.5m over 20 years.

The Best Case with IPRR and Cost Reflective Pricing case again includes large and small customers due to net benefits to both customer types. An additional 23k devices per year, 0.4m over the 20-year modelled lifetime, would need to be enrolled in flexibility and CRP arrangements to break even, or 2% of flexible CER devices.

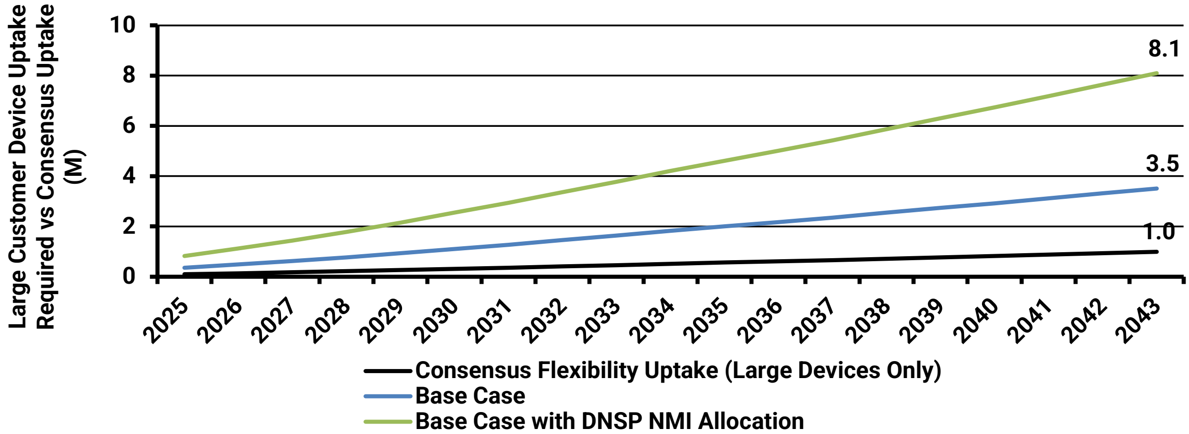
Figure E3 – Breakeven Flexible CER Uptake Required vs. Consensus (Large and Small Customers)



Source: Energeia Modelling, AEMO ISP, E3

Without small customer participation, the benefits of the rule change do not exceed costs. The necessary take-up of secondary settlement points exceeds the forecast number of large customer devices. This is shown in Figure E4 below.

Figure E4 – Breakeven Flexible CER Uptake Required vs. Consensus (Large Customers Only)



Source: Energeia Modelling, AEMO ISP, E3

Under the Base Case and Base Case with DNSP NMI Allocation scenarios, only large customers are assumed to participate as there was a net loss under the small customer case study. The results show that significantly more devices would be required to uptake a secondary settlement point than the number of flexible devices that are anticipated in the NEM, per the consensus forecasting.

Active vs Passive Customers

Energeia also analysed the proposed rule change's impacts on active vs. passive customers. Passive customers are defined here as any customers with a NMI that does not have load flexibility or does have it and chooses to not participate in load flexibility programs, which contrasts with active customers, who have flexible CER and are participating in CER flexibility programs.

Ultimately, Energeia and the AEMC determined that the rule change would be expected to impact the outcomes of active and passive customers in the same way, due to retailer behaviour, which prefers to smear some costs across all customers to simplify customer decisions and other operational reasons. Key assumptions made in reaching this conclusion include:

- All costs considered in the scenarios are shared between all customers via their retail tariffs. This includes the shared system upgrade costs and the costs incurred per device for installing new meters at the premises and allocating a new NMI.
- It is common practice for retailers to not directly charge customers for a standard meter installation, but instead to smear the recovery of that cost into their tariffs.
- It is therefore reasonable to assume that in the event of this rule change retailers would smear the NMI allocation cost in the same way to reduce the direct cost to active customers, whom they want to attract to their product.
- Metering providers spoken to by the AEMC indicated that their costs would scale proportionally to uptake, reducing risks associated with the level of participation to pay for the upfront costs of rule change implementation – at least for NMI-related costs.

Draft Findings, Conclusions, and Recommendations

Based on the analysis of the associated costs, Energeia notes that two of the four scenarios are expected to be cost-effective for customers with flexible CER, and therefore capable of breaking even.

Throughout the analysis, Energeia did not identify any modifications to the proposed rule changes that could result in a more optimal outcome.

Longer-term, Energeia has identified the following key regulatory barriers for the AEMC's consideration in future rule changes:

- **Remove barriers to the use of flexible CER for network services:** Flexible CER must be of sufficient size and dependability and be lower cost than alternatives to provide network services. This is more likely to be the case over time, as more CER is deployed, but also more likely where investment incentives are cost-reflective and there is no network capital expenditure (capex) bias.
- **Remove barriers to using devices for market ancillary service specification (MASS) compliant metering**: Energeia found FCAS to be a key value driver for flexible CER but notes that FCAS currently faces significant barriers to access, mainly metering requirements. Enabling the use of devices for MASS compliance, provided they meet operational requirements, would unlock access to the significant FCAS value stream.
- **Ensure cost-reflective network and retail incentives:** Establishing cost-reflective network and retail prices may allow for more efficient CER utilisation. Current arrangements lead to conflict between retail bill savings and system savings and result in sub-optimal CER utilisation. Cost-reflective pricing would enable 100% flexible CER utilisation and maximise system benefits.
- **Level the playing field for third parties:** Currently, retailers have an upper hand in accessing the value of CER flexibility through existing access to the wholesale value. Allowing third-party aggregators equal access to these benefits will increase competition amongst CER flexibility service providers, generating additional value for consumers.

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1. Background

In May 2022, the Australian Energy Market Operator (AEMO) submitted a rule change request to the Australian Energy Market Commission (AEMC), entitled Flexible Trading Arrangements (Model 2) and Minor Energy Flow Metering in the National Electricity Market (NEM). The rule change request proposed enabling consumers to have their CER separately identified and treated independently in market settlement – to help unlock the value of CER. It also proposed introducing flexible metering arrangements to make it easier to meter CER and other technology such as streetlights.

This report is designed to inform the AEMC's consideration of AEMO's rule change request. The purpose of this report is to communicate the results of Energeia's research, analysis and modelling of the impacts, costs, and benefits of a range of policy scenarios related to allowing a secondary settlement point (SSP) to enable greater CER flexibility. This report also provides an analysis of future directions for the AEMC to consider, which target policy scenarios that maximise the potential value from CER flexibility.

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1.1. The Rule Change

The AEMO's rule change request to the AEMC's Flexible Trading Arrangements (Model 2) and Minor Energy Flow Metering in the NEM seeks to enable end users to separate their controllable electrical resources and have them managed independently from their passive load without needing to establish a second connection point.[6] The AEMO model also allows for a consumer to contract with more than one financially responsible market participant (FRMP) if they choose to do so[6] .

This rule change is one of the many CER implementation reforms underway. Other rule changes and reviews that have an impact on this analysis include but are not limited to:

- Integrating Price-Responsive Resources (IPRR) into the NEM,
- Review of the Regulatory Framework for Metering Services,
- Review into CER Technical Standards,
- Consumer Protections for Future Energy Services,
- Development of Interoperability Policy,
- Accelerating the Roll Out of Smart Meters Rule Change,
- Electricity Pricing for a Consumer-Driven Future Review,
- Review of the Regulatory Framework for Flexible Export Limit Implementation,
- Network Visibility for the Market.

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[5] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources: DRAFT Cost-Benefit Analysis (2024), https://www.aemc.gov.au/sites/default/files/2024-02/Energeia%20report%20_%E2%80%98Benefit%20Analysis%20of%20Load%20Flexibility%20from%20Consumer%20Energy%20Resources%20Draft%20Cost-Benefit%20Analysis%E2%80%99..pdf

[6] AEMO, Rule change request (2022), https://www.aemc.gov.au/sites/default/files/2022-05/ERC0346%20Rule%20change%20request%20pending.pdf

1.2. Methodology Report

The AEMC published Energeia's Draft Methodology Report[7] alongside its Directions Paper,[8] which outlined the proposed rule change assessment methodology and work to date. The modelling in this report reflects the feedback Energeia received from the public consultation.

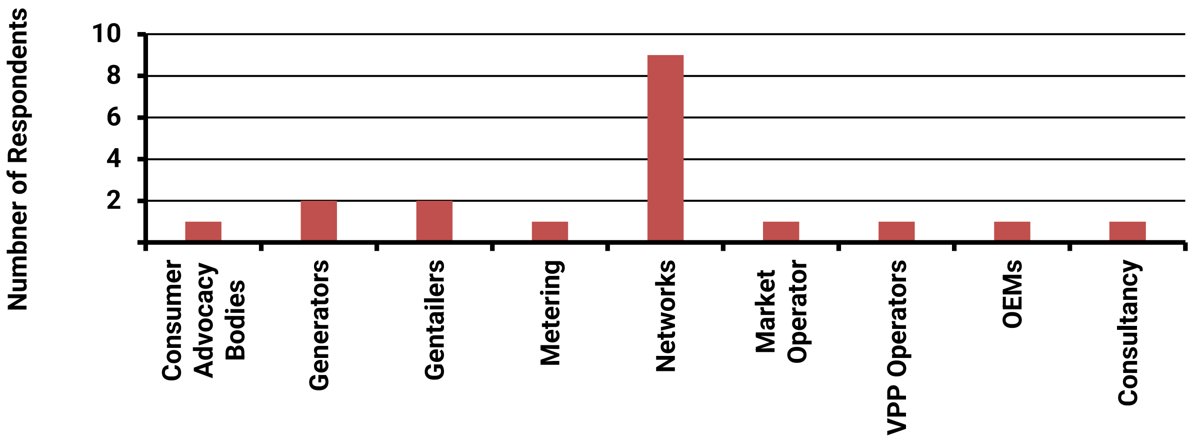
1.3. Draft Determination

The AEMC published Energeia's cost-benefit analysis (CBA) of load flexibility from CER[9] alongside the Draft Determination.[10] Energeia's revised CBA documented in this report builds on the Draft Determination analysis and incorporates the stakeholder feedback received. Key aspects of this stakeholder feedback are summarised below, with a full summary documented in Appendix A: Feedback Received on Draft Determination.

1.4. Stakeholder Feedback to the Draft Determination

Public stakeholders engaged with the Draft Determination through public submissions, providing feedback which Energeia has consolidated and summarised below. Figure 1 shows the number of respondents by stakeholder organisational type. Figure 2 shows the number of comments by cost and benefit streams.

Figure 1 – Draft Determination Feedback, Respondents by Respondent Type



Source: AEMC Draft Determination Feedback, Various Stakeholders

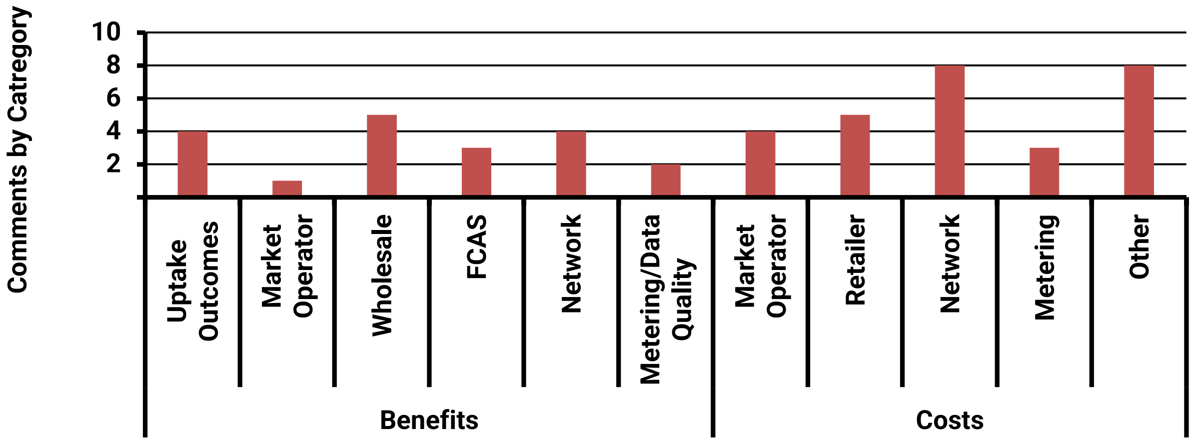
[7] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Methodology Report (2023), https://www.aemc.gov.au/sites/default/files/2023-08/CER%20Flexibility%20Modelling%20Methodology%20Paper%20-%20FINAL.pdf

[8] AEMC, Directions Paper: National Electricity Amendment (Unlocking CER Benefits Through Flexible Trading) Rule 2023 (2023), https://www.aemc.gov.au/sites/default/files/2023-08/ERC0346%20CER%20Benefits%20Directions%20paper%20-%20rule%20change.pdf

[9] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources (2024), https://www.aemc.gov.au/sites/default/files/2024-02/Energeia%20report%20_%E2%80%98Benefit%20Analysis%20of%20Load%20Flexibility%20from%20Consumer%20Energy%20Resources%20Draft%20Cost-Benefit%20Analysis%E2%80%99..pdf

[10] AEMC, National Electricity Amendment (Unlocking CER benefits through flexible trading) Rule (2024), https://www.aemc.gov.au/sites/default/files/2024-02/Draft%20determination%20-%20Unlocking%20CER%20benefits.pdf

Figure 2 – Draft Determination Feedback, Comments by Category



Source: AEMC Draft Determination Feedback, Various Stakeholders

Stakeholder feedback on our CBA Report is summarised into four key addressable areas in Table 1 below. Energeia has incorporated the key feedback into the CBA as revised inputs and scenarios where it could be substantiated. A full summary of stakeholder feedback with Energeia's responses can be found in Appendix A: Feedback Received on Draft Determination.

Table 1 – Feedback Relevant to Draft Determination CBA

CBA Element	CBA Draft Position	Submission Feedback	Energeia Response
Value of visibility to networks of in-built revenue metering having a national metering identifier (NMI)	$0.42 / device / year for small customers	Distribution network service providers (DNSPs), primarily South Australia Power Networks (SAPN), suggested benefits are materially lower than the CBA assumed. SAPN noted visibility provided to a DNSP at the device level does not provide material benefits compared to site-level visibility	Energeia has removed these benefits from the CBA, see for more detail Section 3.2.
Value of having additional in-built revenue metering (i.e. avoided Type-4 metering)	$16.38 / device / year for large and small customers with network services	DNSPs SAPN and Endeavour Energy noted that networks do not need separate Type-4 metering for network services contracting. Electric Vehicle Council and Landis & Gyr note the costs of inbuilt metering gaining pattern approval are not zero, and therefore the avoided cost of metering is not the entire cost of Type 4 metering.	Energeia has reduced the value of this benefit for small customers to reflect the fact that not all network use cases require a revenue-grade meter.
Network system upgrade and NMI allocation costs	Negligible	Networks commented that if they allocate and manage 2nd NMIs their costs would vary from $7m up to $28 million per DNSP (Powercor / CitiPower/United claimed $50-70m total for the three DNSPs under their umbrella)	Energeia's revised scenarios consider varied network cost options for 2nd NMI allocation. Energeia has implemented an alternative NMI allocation and management scenario assuming metering providers are responsible for this role instead of networks.
Related Rule Changes	Not Considered	Stakeholders commented on the need for recognition of the value of related rule changes when considering a rule change with a significant inter-relationship with other rule changes	Energeia's revised scenarios have incorporated the value of the related rule changes of Integrating Price-Responsive Resources (IPRR) and Cost-Reflective Pricing (CRP) reform

Source: AEMC, Submission Feedback, Energeia

2. Scope and Approach

The AEMC engaged Energeia to develop an estimate of the economic costs and benefits of unlocking flexible CER[11] across a range of potential rule change scenarios – including rule changes not incorporated in the current rule change process – as well as to estimate the impact of associated wealth transfers between customer types, and to conduct a breakeven analysis. Energeia developed the work with the AEMC to inform the Directions Paper, Draft and Final Determinations, and future work.

2.1. Scope

This analysis aimed to estimate the incremental costs and benefits of the AEMC's proposed rule change and determine the required uptake of CER to economically break even on rule change costs.

Energeia modelled the above outcome using a fit-for-purpose Microsoft Excel-based modelling tool that estimated the material costs and benefits of flexible CER for the system and consumers, and, crucially, enabled the quantification of the benefits needed to be realised by a potential AEMC rule change to be cost-effective. The modelling included the flexible load types and consumer segments outlined in Appendix A across the NEM to 2050.

> The scope of this engagement was not to forecast the impact of a potential rule change on system costs, but to estimate the quantum of system benefits that load flexibility could potentially provide and how large these benefits and the consumer allocation would need to be to justify the industry costs associated with a potential rule change.

The analysis outlined in Energeia's Methodology Report[12], consistent with the AEMC's Directions Paper, fell under two phases of objectives:

- **Phase A** – to determine the incremental value of the most promising CER load flexibility options in terms of benefits to the electricity system and to consumers, considering an expected sharing of benefits across supply chain participants, and
- **Phase B** – to determine the economic impacts, costs, and benefits of proposed rule changes on the system, and the required threshold of incremental uptake to ensure that this rule change is viable for market participants and consumers.

This report covers the Phase B scope. Phase A analysis is not included in this report, and the Phase A workstream outcomes will be published independently of the Final Determination.

We have developed a separate report that focuses on the costs and benefits associated with Workstream 3 of the rule change (measuring energy flows using in-built technology) associated with streetlights and public EV chargers.[13]

2.2. Approach

Energeia worked closely with the AEMC to deliver the following scope and approach to publish this analysis alongside the AEMC's Final Determination. The key project steps for Phase B included:

- Review and Undertake Stakeholder Engagement,

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[11] CER for the purposes of the rule change request is defined in Chapter One of the Directions Paper.

[12] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Methodology Report (2023), https://www.aemc.gov.au/sites/default/files/2023-08/CER%20Flexibility%20Modelling%20Methodology%20Paper%20-%20FINAL.pdf

[13] AEMC, Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis – Draft Report (2023), https://www.aemc.gov.au/sites/default/files/2024-02/Energeia%20Draft%20Report-%20Measuring%20Energy%20Flows%20from%20In-Built%20Technology%20%28Streetlights%2C%20EV%20Chargers%2C%20Other%20Street%20Furniture%29%20Analy.pdf

- Revise Inputs and Assumptions,
- Define Rule Change Policy Options,
- Analyse Rule Change Impacts,
- Develop Recommendations.

The following sections summarise each step.

Review and Undertake Stakeholder Consultation

Energeia reviewed stakeholder feedback in response to the Draft Determination. The submissions, available online[14], were reviewed and summarised by Energeia. Energeia's responses to stakeholder feedback are summarised in Appendix A: Feedback Received on Draft Determination. Further engagement was undertaken in forums hosted by the AEMC and direct engagement with relevant stakeholders, which Energeia attended. The inputs provided in these workshops have been incorporated into this CBA.

Revise Inputs and Assumptions

Energeia updated and validated the additional inputs used in the revised CBA. Inputs were updated in response to general stakeholder feedback, or revised inputs provided directly by stakeholders.

The revised inputs are detailed in Section 3.

Define Rule Change Policy Options

Energeia worked closely with the AEMC to revise the rule change implementation scenarios based on the stakeholder feedback provided, and the revised inputs. The options aimed to more accurately represent costs to stakeholders and find lower-cost options for implementation for consumers.

The policy options modelled within this cost-benefit analysis are contained in Section 3.1.

Analyse Rule Change Impacts

Energeia estimated the economic costs and benefits of each updated rule change option via the same case study methodology used previously and estimated the level of uptake needed for the scenario to break even at a system-wide level.

Section 3.1 details the economic cost-benefit case study, Section 3.2 details the breakeven analysis.

Develop Recommendations

Energeia has developed updated recommendations based on the findings of the CBA. Section 5 documents the recommendations developed based on the CBA.

[14] AEMC, Unlocking CER benefits through flexible trading (2024), https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

3. Value of the Rule Change (Phase B)

Phase B analysed the economic impacts of key rule change options, the adoption required to break even on the estimated costs of the rule change, and the potential value of load flexibility unlocked by removing the key policy and regulatory barriers that would remain.

Energeia segmented the Phase B analysis into three components:

- **Economic Cost-Benefit Case Study** – this analysis modelled the value of the proposed policy options that were conceptualised through a series of case study cost-benefit assessments, to analyse the rule change impact per customer.
- **Breakeven Analysis** – this analysis determined the level of the CER flexibility uptake that would be required for benefits to outweigh the costs, and
- **Future Directions** – this analysis was an extension of the economic CBA case studies conducted, but with additional policy scenarios to consider the value of better-enabling frequency control ancillary services (FCAS) as well as network and retail cost-reflective pricing for CER. The future directions are included in Appendix C: Future Directions.

The following section details the first of the above components.

3.1. Economic Cost-Benefit Case Study

Energeia conceptualised the value of the proposed policy options through a series of case study cost-benefit assessments, to analyse the impact of the rule change on a per-customer basis. The following section summarises the context and anticipated outcomes of the rule change.

Large Customers

Current market arrangements enable the subloads of large customers to be separately metered and visible to the market operator, unlike small customers, through the embedded network framework. However, networks do not have visibility of this subload. Any network demand management programs for specific devices, while currently possible under existing arrangements, and at the network's discretion, may require the installation of an additional standard meter at the premises of large customers.

This rule change would provide a more appropriate and enduring framework for large customers to engage multiple FRMPs and establish secondary settlement points. Large customers could also use devices with in-built metrology for metering at secondary settlement points, effectively establishing the CER as a separate load from the premises (though still sub-metered). This device could have its own separate FRMP, different to the FRMP for other subloads on the premises and be metered using the in-built metrology of the CER (subject to compliance). Networks would have visibility of this load, and device metering would need to comply with National Measurement Institute requirements to allow for this.

Small Customers

For small customers, current arrangements with market and network operators and regulators do not recognise a flexible CER device in the market. Network demand management programs for specific devices, while possible under existing arrangements, at the network's discretion may require the installation of an additional standard meter at a premises, such as through a controlled load arrangement.

The rule change will enable the establishment of an additional NMI at a customer's premises to identify a given flexible device, creating a secondary settlement point. It would leverage the ability to optionally use CER flexibility without additional metering installations at the premises by instead recognising the in-built metrology of CER as a metering type compliant with the NER. These new meter types would be required to comply with specifications set in AEMO's procedures and the National Metering Institute requirements. For small customers, one FRMP is allowed at a premises under this rule change.

3.1.1. Methodology

The methodology of this stage included the following steps:

1. **Develop policy options** – Energeia worked closely with the AEMC to develop revised scenarios. This was done in response to consultation feedback, as below:
    a. **Review public consultation feedback** – Energeia reviewed the provided feedback to the Draft Determination. Relevant submissions to Energeia, with responses are included in Appendix A: Feedback Received on Draft Determination, and
    b. **Engage in targeted consultations** – The AEMC undertook targeted consultations to inform the costs and benefits of the additional roles associated with the rule change.
2. **Develop further inputs** – This included the development of policy costs and benefits inputs. Energeia has revised inputs to the modelling based on stakeholder feedback.
3. **Test customer outcomes as a case study** – The scope of this work required testing the marginal impact on customers across proposed rule change implementation options for customers. The case study analysis demonstrates the net costs and benefits for both a representative flexible unidirectional load and bidirectional CER for each customer segment – to determine if the rule change is net beneficial for each case.
    a. For Large Customers, the selected case study loads were:
        i. Unidirectional load: Ventilation unit (70, 098 kWh/year)[15]
        ii. Bidirectional load: 150 kWh Battery
    b. For Small Customers, the selected case study loads were:
        i. Unidirectional load: EV charger (2,240 kWh/year)
        ii. Bidirectional load: 10 kWh Battery

Energeia worked with the AEMC to identify CBA categories, which are described in Table 2.

Table 2 – Cost and Benefit Allocation in CBA

Cost or Benefit	Description
Retailer: Region Reference Price (RRP) Benefits	Avoided wholesale energy costs to the retailer from CER flexibility. Energeia estimated this value for each case study using outputs from the CER Flexibility Optimisation Tool
Network: Network Peak Benefits	Avoided augmentation costs for the network to meet peak demand or additional solar photovoltaic (PV) hosting capacity using CER flexibility. Energeia estimated this value for each case study using outputs from the CER Flexibility Optimisation Tool
Consumer: Emissions Benefits	Avoided emissions through the optimal use of flexible CER for the system
Consumer: System Benefits	Uptake of IPRR reducing instances of errors in demand forecasts, resulting in lower wholesale prices
Market Operator: Shared Costs	System upgrade costs for AEMO to accommodate the rule change
Retailer: Shared Costs	System upgrade costs for retailers to accommodate the rule change
Network: Shared Costs	System upgrade costs for networks to accommodate the rule change.
NMI Service Provider: Shared Costs	System upgrade costs for the NMI service provider to accommodate the rule change
Consumer: Per Device Costs	Metering and NMI allocation costs which may be incurred by the customers for using flexible CER, which are passed through by the retailer. These scale on a per-device level, but are assumed to be smeared across all customers

Source: Energeia

[15] A ventilation load (unit or fan) used for air quality purposes, separate from heating or cooling loads

3.1.2. Policy Scenarios

Energeia defined the impact of the rule change as how it would alter the market arrangements for customers wishing to partake in CER flexibility services. The focus of this rule change is on separately identifying and measuring a consumer's CER cost-effectively. Improving these arrangements may allow or enable:

- consumers to have different network and retail pricing offers for their CER assets based on their individual preferences from their passive load, or to be offered direct payments for the use of their assets,
- energy service providers to better participate in wholesale energy market scheduling,
- networks to procure demand and export management services more efficiently from these resources, helping to reduce the need for network augmentation,
- an aggregated resource that the market operator (AEMO) could use to deliver secure, reliable, and low-emissions energy at a lower cost, and
- importantly, through the above mechanisms, the unlocking of some of the expected benefits of current and future reforms including cost-reflective pricing.

Standardising and streamlining the process for establishing load flexibility programs for service providers will subsequently lower transaction and metering costs below current levels. This would improve competition in the market by reducing the barriers to entry for new providers.

Energeia worked closely with the AEMC to update the key inputs and scenarios in response to stakeholder feedback into a revised CBA. The stages of this are outlined below:

- **Review and Undertake Stakeholder Engagement** – Energeia reviewed stakeholder feedback in response to the Draft Determination and attended targeted stakeholder engagement with the AEMC and key stakeholder groups,
- **Revise Inputs and Assumptions** – Energeia updated and validated the additional inputs required for the revised CBA. Inputs were updated in response to general stakeholder feedback, or revised inputs provided directly from stakeholders,
- **Define Rule Change Policy Options** – Energeia worked closely with the AEMC to develop the revised scenarios. Updated to the scenarios were made in response to stakeholder feedback,
- **Analyse Rule Change Impacts** – Energeia estimated the economic costs and benefits of each updated rule change option via a series of case studies, and estimated the level of uptake needed to break even on the rule change costs at a system-wide level,
- **Develop Recommendations** – Energeia has developed updated recommendations based on the findings of the CBA.

Table 3 outlines how these scenarios have been applied to each cost and benefit of the CBA, compared to the inputs utilised in the Draft Determination. These scenarios are as follows below:

- **Base Case**: This scenario assumes that NMI service providers will perform the role of allocating NMIs and maintaining standing data at SSP NMIs and need to undertake system upgrades to perform this role.
- **Base Case with DNSP NMI Allocation**: This scenario assumes that DNSPs will perform the role of allocating NMIs and maintaining standing data at SSP NMIs.
- **Best Case, without Additional Reforms**: This scenario assumes that NMI service providers will perform the role of allocating NMIs and maintaining standing data at SSP NMIs, along with lower system upgrade costs for AEMO and greater benefits for the avoidable cost of metering.
- **Best Case with IPRR and Cost Reflective Pricing:** This assumes the Base Case but includes benefits from CRP and IPRR reforms. This assumes system upgrades from the DNSP to provide cost-reflective network pricing to the SSP.

Table 3 – Final Rule Change Scenarios by CBA Element

Benefit /Cost	CBA Element	CBA Draft Position	Scenarios				Explanation
			Base Case	Base Case with DNSP NMI Allocation	Best Case, without Additional Reforms	Best Case with IPRR and Cost Reflective Pricing	
Benefit	Avoidable Small Customer[1] Type-4 Metering Costs for Network Services	$16.38 / device / year	25% avoidable	25% avoidable	75% avoidable	25% avoidable	This reflects that networks don't use metering for thermal relief network services (e.g. asset investment deferral) in many cases. Additionally, the cost of pattern-approved in-device metering is not zero. However, the secondary tariff-based controlled load is the largest demand response (DR) resource in Australia.
	Cost Reflective Network and Retailer Pricing	Excluded from Rule Change	Excluded	Excluded	Excluded	Included	This reflects that networks having access to revenue-grade metering data at secondary points should make it easier to offer cost-reflective prices for flexible devices, including location-based, real-time pricing. However, this does not guarantee customers will take it up.
	Societal Benefits of FRMPs Participating in Dispatch through IPRR	Not Considered	Excluded	Excluded	Excluded	Included	This reflects the rule change inducing further uptake of IPRR, reducing instances of errors in demand forecasts, leading to lower wholesale prices and frequency control ancillary services (FCAS) requirements.
Cost	System Upgrade Costs (Incurred by DNSPs)	Negligible	-	$1.71 / device / year[2]	-	$1.71 / device / year[2]	This reflects feedback from networks that performing the role of NMI allocation for secondary points would require costly system upgrades. These are required to establish a hierarchy in their systems to receive NMI standing data and to manage interactions with AEMO's market settlement and transfer solution (MSATS). The NMI service provider option reflects costs associated with the alternative scenario of NMI allocation at secondary points to be managed by an accredited NMI service provider instead of DNSPs.
	System Upgrade Costs (Incurred by NMI Service Providers)		$0.99 / device / year[3]	-	$0.99 / device / year[3]	$0.99 / device / year[3]	
	NMI Allocation Costs (Incurred by DNSPs)	$8.42 / device / year Incurred by DNSPs	-	$8.42 / device / year	-	-	
	NMI Allocation Costs (Incurred by NMI Service Providers)		$2.81 / device / year[4]	-	$2.81 / device / year[4]	$2.81 / device / year[4]	
	AEMO and Retailer System Upgrade Costs	$0.49 / device / year / system	Align with DER Integration Program Costs ($0.49 / device / year / system)	Align with DER Integration Program Costs ($0.49 / device / year / system)	50% lower ($0.25 / device/year / system)	Align with DER Integration Program Costs ($0.49 / device / year / system)	Reflects feedback that AEMO and retailer systems are already able to support activities proposed in the rule change. Sensitivity is due to uncertainty in the cost of this upgrade, rather than any functional variation.

Source: Energeia

[1] The $16.38/customer has been maintained for large customers.

[2] Derived from average value in system upgrade costs received from networks.

[3] Derived from the lowest value in system upgrade costs received from networks.

[4] Derived from the advice from embedded network managers and metering coordinators.

3.1.3. Inputs

This section outlines the scope of inputs utilised in this modelling.

Rule Change Cost Assumptions

The input costs for large customers and small customers by scenario are shown in Table 4 and Table 5, respectively. The costs were categorised by the key stakeholders that they would affect, with system costs and certification all upfront policy costs. Costs that are incurred on a per-customer basis include NMI allocation costs and meter costs. These costs are typically smeared, and allocated across the consumer basis, however are noted to scale with the uptake of the policy.

Per the feedback, and the revised roles for NMI allocation and management, the additional stakeholder of a NMI service provider has been added to the cost breakdown.

Table 4 – Large Customer Cost Assumptions ($/Year/Device)

Scenario	AEMO	Retailers	Networks	NMI Service Provider	OEM		Consumer		
Name	System Changes				System Changes	Certific-ation	NMI Allocation		Std. Meter
							DNSP-Led	NMI Service Provider-Led	
Status Quo (Embedded Network Framework)	-	-	-	-	-	-	-	-	$16.38
Base Case	$0.49	$0.49	-	$0.99	Negligible	Negligible*	-	$2.81	-
Base Case with DNSP NMI Allocation	$0.49	$0.49	$1.71	-	Negligible	Negligible*	$8.42	-	-
Best Case, without Additional Reforms	$0.25	$0.25	-	$0.99	Negligible	Negligible*	-	$2.81	-
Best Case with IPRR and Cost Reflective Pricing	$0.49	$0.49	$1.71	-	Negligible	Negligible*	-	$2.81	-

Source: Energeia. Note: shaded items indicate costs that scale on a per-device uptake basis
Note: OEM = Original Equipment Manufacturer
*Assumes internet delivery, not, e.g., a dedicated 4G service

Table 5 – Small Customer Cost Assumptions ($/Year/Device)

Scenario	AEMO	Retailers	Networks	NMI Service Provider	OEM		Consumer		
Name	System Changes				System Changes	Certific-ation	NMI Allocation		Std. Meter
							DNSP-Led	NMI Service Provider-Led	
Status Quo (Retailer-Led VPP Framework)	-	-	-	-	-	-	-	-	$16.38[1]
Base Case	$0.49	$0.49	-	$0.99	Negligible	Negligible*	-	$2.81	-
Base Case with DNSP NMI Allocation	$0.49	$0.49	$1.71	-	Negligible	Negligible*	$8.42	-	-
Best Case, without Additional Reforms	$0.25	$0.25	-	$0.99	Negligible	Negligible*	-	$2.81	-
Best Case with IPRR and Cost Reflective Pricing	$0.49	$0.49	$1.71	-	Negligible	Negligible*	-	$2.81	-

Source: Energeia. Note: shaded items indicate costs that scale on a per-device uptake basis
*Assumes internet delivery, not, e.g., a dedicated 4G service, [1]this avoidable cost varies by scenario

The sources of these cost assumptions are as follows:

- **System change costs** to AEMO, retailers, and third-party aggregators are created by the need to upgrade their IT systems to account for additional data streams for large and small customers that undergo market settlement. This was derived from AEMO's reported cost of facilitating the DER Integration Program Costs[16] ($5.2m/year) and was assumed to be equal for retailers. It should be noted that the costs of these system changes were assumed to be allocated per connection point and should therefore be treated as indicative based on the current number of connection points.
- Costs associated with the **installation of an additional/different meter** were based on previous interviews Energeia has conducted with metering coordinators.
- **DNSP system upgrade costs** were revised based on stakeholder feedback from DNSPs. Energeia has utilised the quoted system upgrade costs by DNSPs which were provided in stakeholder meetings and developed this into an annual per-customer value. Energeia used a volume-weighted average WACC of all DNSPs of 4.57% to determine the annual cost of system upgrades per customer over 15 years.
- DNSP costs associated with the **establishment and management of new NMIs** are taken from an Energeia analysis for AEMC on establishing a second connection point[17], which leveraged network pricing schedules of NSW Distributed Network Service Providers (DNSPs). Note that this cost includes the site establishment fee and the connection offer service charge.
- The costs for CER original equipment manufacturers (OEMs) to **comply with metering requirements** and system changes were deemed negligible because manufacturers can leverage existing circuits and measuring capabilities.
- **NMI service provider system upgrade costs** from the lowest cost suggested by DNSPs. These values were used based on advice from stakeholder engagement undertaken by the AEMC and Energeia.
- NMI service provider costs associated with the **establishment and management of new NMIs** were developed based on advice from embedded network managers and metering coordinators.

It should be noted that for all identified non-negligible costs, it is assumed that retailers directly incur these costs but pass them through to all consumers via their retail tariffs.

CER Flexibility Assumptions

The following sections contain all inputs relating to the included representative customers, and the way they are operated flexibly. They were used in the CER Flexibility Optimisation Tool to generate the per-device benefits for cost-reflective pricing in the Best Case with IPRR and Cost Reflective Pricing scenario. Note that this rule change aims to find the lowest-cost option for allowing secondary settlement points. Energeia's modelling of cost-reflective pricing aims to contextualise the role of this rule change regarding future reforms and rule changes that this policy will help to reduce barriers for.

SUBLOADS

The following section covers the selection of subloads, their profiles, consumption, and capacities used as inputs to the modelling.

Subload Profiles

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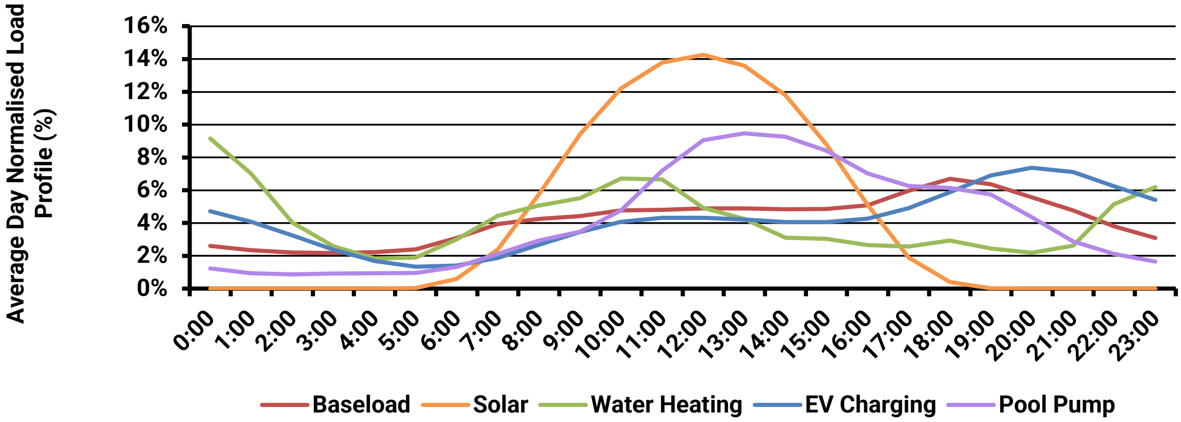
[16] AEMO, 2022-23 AEMO Budget and Fees (2022), https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/aemo-engagement-model/budget-and-fees/aemo-2022-23-budget-and-fees.pdf?la=en

[17] Energeia, Expert Advice on the Cost of Establishing a Second Connection Point (2020), https://esb-post2025-market-design.aemc.gov.au/32572/1608712682-enegeia-expert-advice-on-the-cost-of-establishing-a-second-connection-point.pdf

Appliance load shapes provide the timing of energy consumption of each CER before any load flexibility occurs. They provide the foundation with which load shifting and shedding are modelled in this analysis.

The residential load profiles were sourced from the Residential Baseline Study,[18] and are shown in Figure 3.

Figure 3 – Average Day Residential Normalised Load Shape



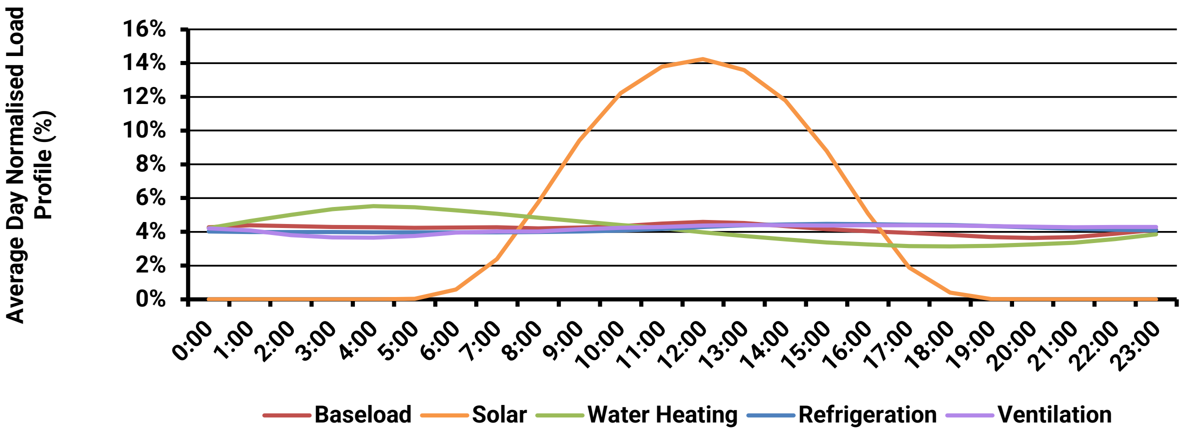
Source: Residential Baseline Study (2022)

Energeia adapted the load shapes for large and small commercial water heating, refrigeration, and ventilation from end-use load profiles for the United States (US) Building Stock (National Renewable Energy Laboratory (NREL)), mapped to Australian capital cities for each NEM state considered. The profiles are shown in Figure 4 and Figure 5.

Energeia mapped each Australian capital to a US city by comparing several different climatic and economic factors, such as average temperature differential, average humidity differential, average daylight differential, average wind differential, average rainfall differential, average income, and average energy prices. Energeia took forward the city that matched most closely, i.e., that had the most factors with low amounts of difference.

US data was used because, to the best of Energeia's knowledge, no publicly available data exists on Australian subload consumption load shapes for commercial premises.

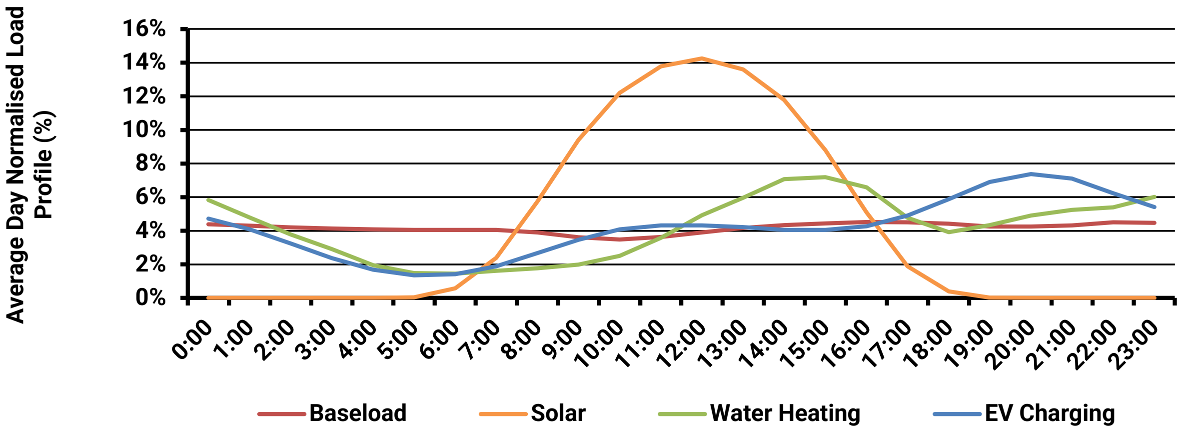
Figure 4 – Average Day Large Commercial Normalised Load Shape



Source: Commercial Baseline Study (2022), NREL

[18] Energy Rating, Residential Baseline Study (2022), https://www.energyrating.gov.au/industry-information/publications/report-2021-residential-baseline-study-australia-and-new-zealand-2000-2040

Figure 5 – Average Day Small Commercial Normalised Load Shape



Source: Commercial Baseline Study (2022), NREL

The solar PV load shapes were adapted from NREL's PV Watts tool for each capital city in each NEM state. The EV charging load shapes were sourced from the AEMO 2023 Inputs, Assumptions and Scenarios Report (IASR). The convenience charging load shapes were taken forward for this analysis.

Annual Consumption and Capacity

The following section demonstrates the size of the representative customers utilised in the case study modelling. The annual consumption inputs for each subload are shown in Table 6, Table 7, and Table 8, for the residential, small commercial, and large commercial segments. These consumption values are per premises and were used to scale the normalised consumer load profiles to a per premises level. The per-premises profiles were then scaled based on forecast CER and flexibility uptake by segment and state.

Table 6 – Residential Annual Consumption by Subload

Baseload (kWh)	Water Heating (kWh)	EV Charging (kWh)	Pool Pump (kWh)
4,011	996	2,240	1,099

Source: Energeia

Table 7 – Small Commercial Annual Consumption by Subload

Sub Segment	Baseload (kWh)	Water Heating (kWh)	EV Charging (kWh)
Offices	16,253	255	2,240
Retail	16,461	46	2,240
Accommodation	16,196	311	2,240
Entertainment	16,199	309	2,240
Warehouses	16,414	93	2,240
Health	16,225	322	2,240

Source: Energeia

Table 8 – Large Commercial Annual Consumption by Subload

Sub Segment	Baseload (kWh)	Water Heating (kWh)	Refrigeration (kWh)	Ventilation (kWh)
Offices	417,861	27,300	-	70,098
Retail	397,161	15,958	-	102,139
Accommodation	342,595	106,076	2,920	63,667
Entertainment	414,406	26,408	4,836	69,609
Warehouses	348,750	2,114	-	164,395
Health	375,987	64,490	1,039	73,743

Source: Energeia. Note: Office consumption was utilised in the case study modelling

For generation and storage devices, the capacities of each subload are shown by segment in Table 9. These were used to determine the generation and load-shifting capabilities of these CER devices.

Table 9 – Subload Capacities by Segment

Segment	Solar PV (kW)	Battery (kW/kWh)	V2G (kW/kWh)
Residential	7.5	5/10	5/5.83
Small Commercial	30	5/10	5/5.83
Large Commercial	100	75/150	-

Source: Energeia
Note: Stationary battery and vehicle-to-grid (V2G) capacities are dictated by export limits

CER FLEXIBILITY ORCHESTRATION STRATEGIES

The modelling mechanisms through which CER flexibility was considered for each load type are summarised in Table 10 and Table 11, for large and small customers, respectively. They were intended as an approximation of what CER flexibility would look like in reality, rather than a complete strategy. Device types not used in the case studies are displayed in the tables for comparative purposes.

Table 10 – CER Flexibility Modelling Mechanisms: Large Customers

<table>
<tr><th>Device Type</th><th>No Orchestration</th><th>Wholesale Price Orchestration</th><th>Tx Orchestration</th><th>Dx Orchestration</th><th>FCAS Orchestration</th></tr>
<tr><td>Storage Water Heater (100% power flexible)</td><td rowspan="4">Operates per base subload</td><td rowspan="3">Shifts all flexible consumption from highest price to lowest price, daily</td><td rowspan="3">Shifts all flexible consumption out of the peak network period and into the minimum network period, defined as the top 1.4% peak/minimum demand hours on the network</td><td rowspan="3">Shifts all flexible consumption out of peak network period and into minimum network period, defined as top as top 1.4% peak/minimum demand hours on network</td><td rowspan="5">Flexible loads and generation bid into the highest value market between 6 sec – 5 min for raise and lower, but does not change load behaviour from the optimal state</td></tr>
<tr><td>Refrigeration[1] (100% power flexible)</td></tr>
<tr><td>Ventilation[2] (100% power flexible)</td></tr>
<tr><td>Solar (100% power flexible)</td><td>Curtailed when RRP < 0 $/MWh</td><td>No solar exports during the minimum period</td><td>No solar exports during the minimum period</td></tr>
<tr><td>Battery (100% power flexible)</td><td>Charges during excess solar and immediately discharges as soon as grid consumption is recorded
Does not export to the grid</td><td>Charges during lowest RRP price intervals to fully charge the battery. Discharges during the highest RRP prices of the day to fully discharge the battery.
Can export to the grid</td><td>Charges during network minimum period, discharges during network peak period. If neither occurs in a day, the battery performs bill minimisation behaviour
Can export to the grid</td><td>Charges during network minimum period, discharges during network peak period. If neither occurs in a day, the battery performs business as usual (BaU) behaviour.
Can export to the grid</td></tr>
</table>

Source: Energeia
[1]Includes refrigeration units and freezers for cold storage
[2]Includes ventilation units and fans for maintaining air quality – separate from heating or cooling loads
[3]Off-peak period assumed to have sufficient hours within which to recharge.

Table 11 – CER Flexibility Modelling Mechanisms: Small Customers

<table>
<tr><th>Device Type</th><th>No Orchestration</th><th>Wholesale Price Orchestration</th><th>Tx Orchestration</th><th>Dx Orchestration</th><th>FCAS Orchestration</th></tr>
<tr><td>Storage Water Heater (100% power flexible)</td><td rowspan="4">Operates per base subload</td><td rowspan="3">Shifts all flexible consumption from highest price to lowest price, daily</td><td rowspan="3">Shifts all flexible consumption out of the peak network period and into the minimum network period, defined as the top 1.4% peak/minimum demand hours on the network</td><td rowspan="3">Shifts all flexible consumption out of the peak network period and into the minimum network period, defined as the top 1.4% peak/minimum demand hours on the network</td><td rowspan="5">Flexible loads and generation bid into the highest value market between 6 sec – 5 min for raise and lower, but does not change load behaviour from the optimal state</td></tr>
<tr><td>Pool Pump[2] (100% power flexible)</td></tr>
<tr><td>Level 2 EV Charger (availability varies by hour)</td></tr>
<tr><td>Solar (100% power flexible)</td><td>Curtailed when RRP < 0 $/MWh</td><td>No solar exports during the minimum period</td><td>No solar exports during the minimum period</td></tr>
<tr><td>Battery (100% power flexible)</td><td>Charges during excess solar and immediately discharges as soon as grid consumption is recorded. Does not export to the grid</td><td>Charges during lowest RRP price intervals to fully charge the battery. Discharges during the highest RRP prices of the day to fully discharge the battery. Can export to the grid</td><td>Charges during network minimum period, discharges during network peak period. If neither occurs in a day, the battery performs bill minimisation behaviour. Can export to the grid</td><td>Charges during network minimum period, discharges during network peak period. If neither occurs in a day, the battery performs BaU behaviour. Can export to the grid</td></tr>
<tr><td>V2G (100% power flexible, availability varies by hour)</td><td colspan="5">Same logic as the battery. Available charging is factored in by the percentage of vehicles plugged in per hour</td></tr>
</table>

Source: Energeia
[1] Off-peak period assumed to have sufficient hours within which to recharge
[2] Pool pumps modelled only for residential premises
Note: Tx = Transmission, Dx = Distribution, RRP = Regional Reference Price

The modelling methodology implemented by Energeia optimised across the value streams. In the policy options considered within this section, CER loads were modelled to optimise consumption and export (in the case of bi-directional loads) across:

- Minimising wholesale energy cost
- Avoiding transmission and distribution costs

On all other remaining days, customers operate under no orchestration behaviour, which represents customers' current convenience-driven behaviours. In the future policy options explored in Appendix C: Future Directions, the FCAS revenue value stream is also considered.

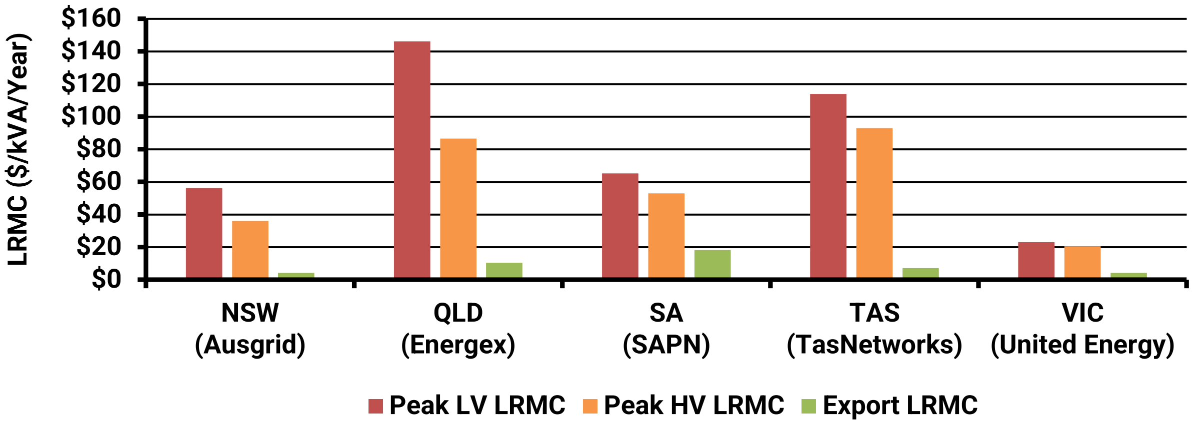
NEM Price Signals

NETWORK LRMC

Network long-run-marginal cost (LRMC) denotes the annualised cost for a network to host an incremental unit of demand. Network LRMC inputs were used for determining the cost impacts of flexible operation on distribution and transmission networks. For each NEM state, Energeia selected a relevant distribution network service provider (DNSP) and transmission network service provider (TNSP) to represent that state in the modelling.

Energeia sourced peak demand distribution network LRMCs directly from DNSP Tariff Structure Statements (TSS) published on the Australian Energy Regulator's (AER's) website. Export LRMCs were taken forward from a previous Energeia analysis for AEMO, which forecasted a bottom-up cost estimation of the least-cost pathway to resolve voltage insufficiency caused by hosting solar PV on the distribution LV network for each DNSP in the NEM. These values are shown in Figure 6.

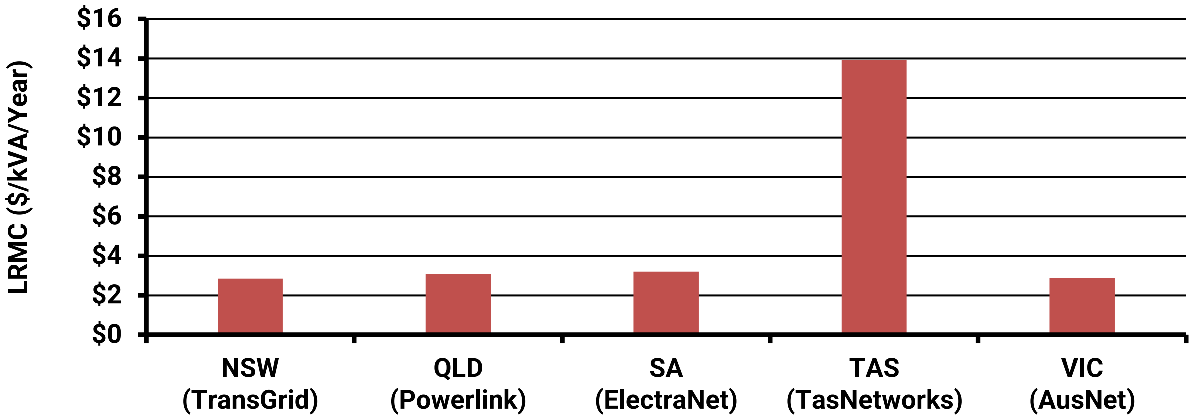
Figure 6 – Distribution Network LRMC Inputs



Source: AER (2023), Ausgrid (2019), Energex (2022), SAPN (2021), TasNetworks (2022), United Energy (2021), Energeia

Transmission network LRMCs are not directly published by TNSPs, so they needed to be estimated for this analysis. To cost the load hosting capacity-driven expenditure, Energeia observed the relationship between each TNSP's stated replacement and augmentation expenditure requirements and their stated annual peak demand to develop an LRMC estimate in $/kVA/year. These values are shown in Figure 7.

Figure 7 – Transmission Network LRMC Inputs

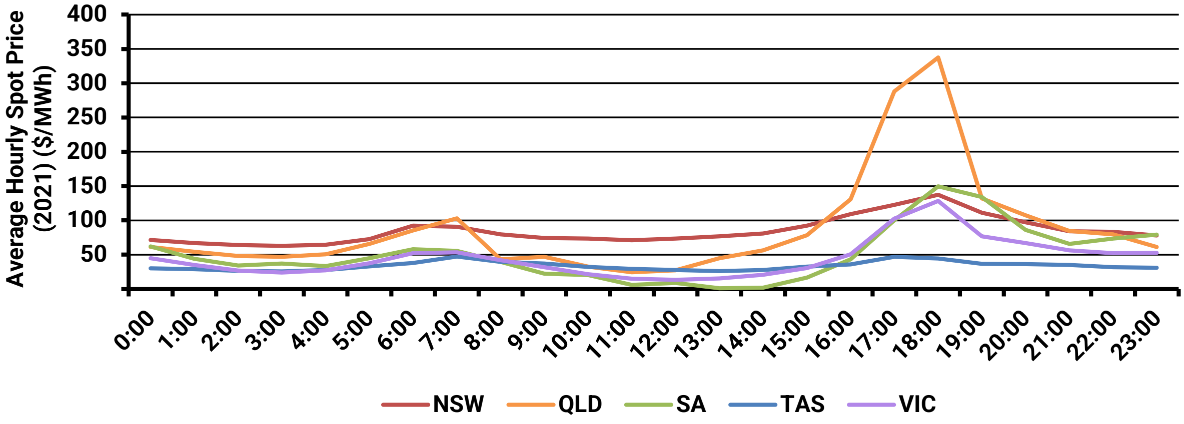


Source: AER (2023), TransGrid (2019), Powerlink (2022), ElectraNet (2021), TasNetworks (2022), AusNet (2021), Energeia

WHOLESALE COSTS

The electricity wholesale RRPs at hourly intervals were used in the model to value the impact of load flexibility on the wholesale market, generally by moving a load from higher-priced time intervals throughout a given day to lower-priced time intervals. The average annual hourly spot market price can be seen in Figure 8. 2021 prices were used to avoid the 2022 price shocks caused by the market shutdown.

Figure 8 – Average 2021 Hourly Spot Price

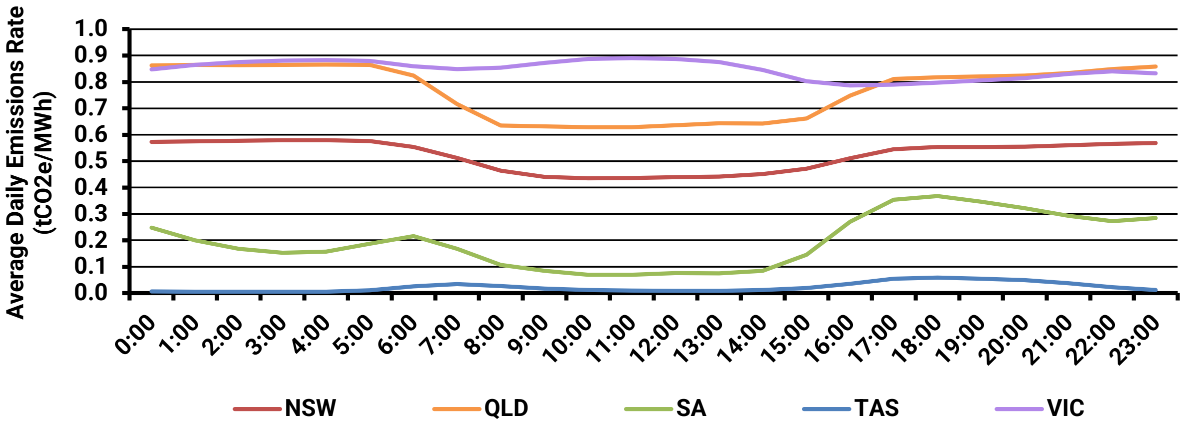


Source: AEMO (2021), Gorman et al. (2018)

EMISSIONS REDUCTION BENEFITS

Energeia calculated the volume of emissions in the NEM from the change in consumption and export (incl. rooftop PV, batteries, and V2G) of consumer devices, as determined by the representative subloads and customer segments, multiplied by the grid emissions factor by hour and by year. Figure 9 below shows the change in emissions intensity by hour[19].

Figure 9 – Average Hourly Emissions Factor



Source: Energeia
Note: CO2e = Carbon Dioxide equivalent

Energeia has implemented the value of carbon emissions reduction (VER)[20] in conjunction with the hourly profile above to capture the value of shifting hourly consumption of loads. The value of carbon abatement in 2023 was $66/tCO2e.

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[19] A yearly emissions profile is used to account for seasonality of emissions.

[20] AEMC, How the national energy objectives shape our decisions (2024), https://www.aemc.gov.au/sites/default/files/2024-04/AEMC%20guide%20on%20how%20energy%20objectives%20shape%20our%20decisions%20March%202024.pdf

System Benefits

In this analysis, system benefits include the benefits that are expected to be unlocked resulting from the parallel IPRR reform. Energeia considers the benefits of IPRR in the Best Case with IPRR and Cost Reflective Pricing scenario to show the indicative value of enabling further reforms.

The AEMC provided Energeia with the draft findings of the benefits of the IPRR rule change, which Energeia has incorporated into the CBA. Using this data, Energeia's modelling assumed $4.5/kW/year of flexible resources worth of benefits to be attributable to the IPRR rule change.

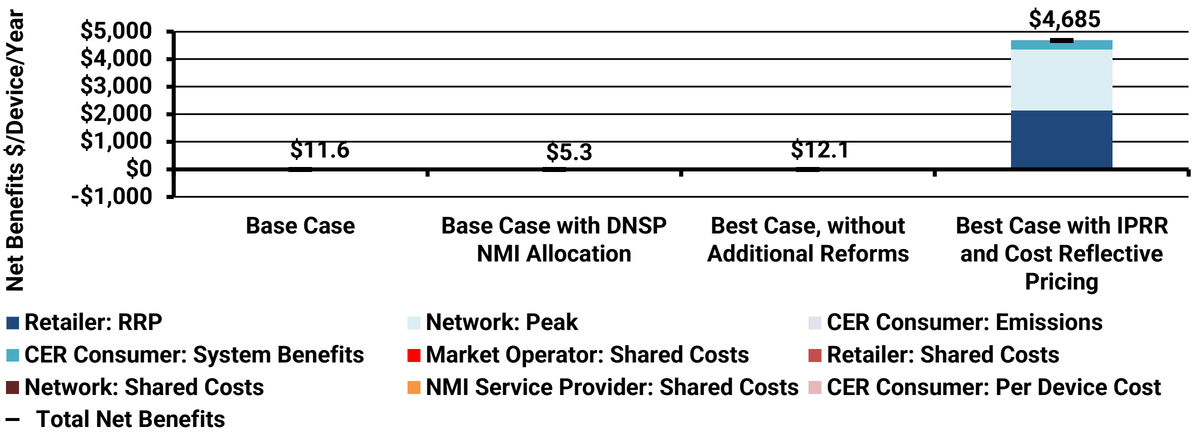
3.1.4. Results

Energeia's revised impact analysis, which is presented below, identified and modelled the key costs and benefits of each rule change scenario relative to the baseline of the status quo for small and large customers. Energeia also updated our calculation of the breakeven point where flexible CER uptake makes each rule change cost economic for customers.

Large Customers

Figure 10 and Table 12 report Energeia's estimate of the net benefits of each scenario against the status quo for large customers with batteries. The results show that under all scenarios, there is a net benefit vs. the status quo (i.e., the embedded network framework, respectively.

Figure 10 – Large Customer Battery Net Benefits Against Status Quo



Source: Energeia Modelling

Table 12 – Summary of Large Customer Battery Net Benefits Against Status Quo

	Net Benefits ($/Year/Device)									
Scenario	Retailer	Network	CER Consumer		Market Operator	Retailer	Network	NMI Service Provider	CER Consumer	Total
Name	RRP	Peak	Emissions	System Benefits	Shared Costs	Shared Costs	Shared Costs	Shared Costs	Per Device Cost	Net Benefits
Base Case	-	-	-	-	-$0.49	-$0.49	-	-$0.99	$13.57	$11.60
Base Case with DNSP NMI Allocation	-	-	-	-	-$0.49	-$0.49	-$1.71	-	$7.95	$5.26
Best Case, without Additional Reforms	-	-	-	-	-$0.25	-$0.25	-	-$0.99	$13.57	$12.09
Best Case with IPRR and Cost Reflective Pricing	$2,144	$2,199	-$6.28	$337	-$0.49	-$0.49	-$1.71	-$0.99	$13.57	$4,685

Source: Energeia Modelling

In all modelled scenarios, the proposed rule change benefits consistently show reduced costs per customer against the status quo by avoiding the requirement for a second meter through the approval of lower-cost inbuilt metering.

The Base Case scenario delivers $11.60 per year per device in net benefits. This scenario's benefits are due to assuming that metering coordinators will assume the NMI allocation and management role.

The lowest net benefit is under the Base Case with DNSP NMI Allocation scenario, which delivers $5.26 in net benefits per device per year. These benefits are mainly due to the avoided cost of installing secondary metering on the site through recognition of inbuilt device metering. However, they are offset by the higher NMI allocation and management costs assumed for DNSPs.

The Best Case, without Additional Reforms scenario, large devices deliver $12.09 per device per year. This scenario additionally assumes that metering coordinators will assume the NMI allocation and management role. This scenario only differs from the Base Case due to a 50% lower assumed system upgrade cost for both AEMO and retailers.

The Best Case with IPRR and Cost Reflective Pricing scenario delivers the highest net benefit at $4,685 per device per year. This scenario's higher net benefit is driven by the assumed avoided retailer RPP and DNSP peak costs as a result of applying more efficient tariffs. This scenario has marginally higher upfront costs than the Base Case due to the assumed DNSP system upgrades required to provide cost-reflective network pricing to a secondary settlement point.

Note, a small magnitude of negative emissions benefits may occur in the cost-reflective pricing modelling as optimising for economic benefits under cost-reflective pricing settings sometimes results in a customer deviating from the default modelled behaviour of charging during solar hours and opting to provide wholesale or network services. Energeia's modelling did not directly optimise to minimise grid emissions.

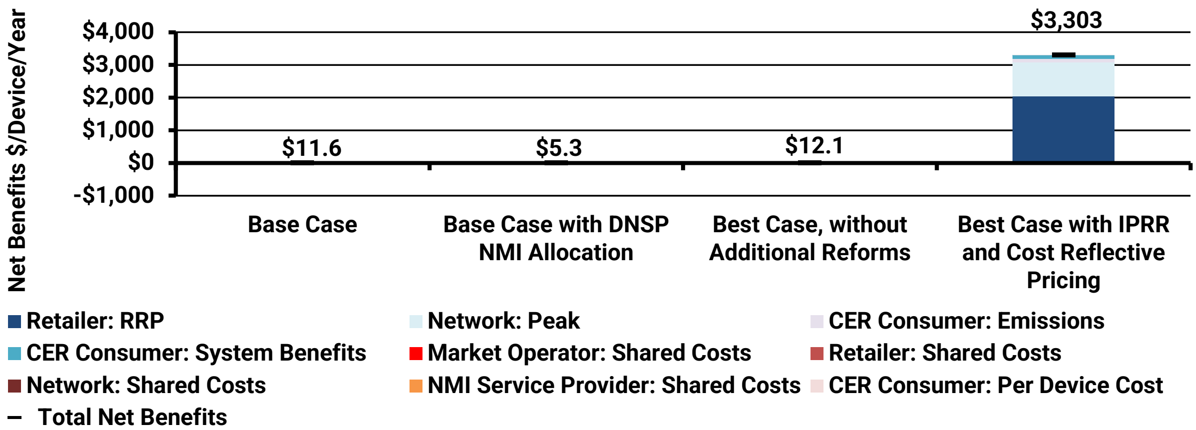
It is important to acknowledge that these benefits depend upon the CRP and IRRP rule changes and their related mechanisms.

1. Secondary settlement points can enable CRP to be sent to the CER device, which in turn unlocks more optimal flexible operation of CER and associated benefits.
2. The related IPRR benefits assumed are accrued through reducing inefficiencies from demand forecast errors captured under the system benefits.

Energeia notes that realising CRP and IPRR benefits requires additional reforms, so this rule change is an incremental change that helps to reduce some barriers for other reforms being developed to capture these benefits.

Similar results can be seen in Figure 11 and Table 13 for the ventilation subload case study. The outcomes are the same across the low and medium benefits scenarios. Outcomes are different for the Best Case with IPRR and Cost Reflective Pricing option due to the incorporation of the benefits from cost-reflective pricing, which allows for the relative flexibility and magnitude of a customer's subload to determine the available benefits.

Figure 11 – Large Customer Ventilation Net Benefits Against Status Quo



Source: Energeia Modelling

Table 13 – Summary of Large Customer Ventilation Net Benefits Against Status Quo

Scenario Name	Retailer RRP	Network Peak	CER Consumer Emissions	System Benefits	Market Operator Shared Costs	Retailer Shared Costs	Network Shared Costs	NMI Service Provider Shared Costs	CER Consumer Per Device Cost	Total Net Benefits
	Net Benefits ($/Year/Device)									
Base Case	-	-	-	-	-$0.49	-$0.49	-	-$0.99	$13.57	$11.60
Base Case with DNSP NMI Allocation	-	-	-	-	-$0.49	-$0.49	-$1.71	-	$7.95	$5.26
Best Case, without Additional Reforms	-	-	-	-	-$0.25	-$0.25	-	-$0.99	$13.57	$12.09
Best Case with IPRR and Cost Reflective Pricing	$2,038	$1,048	$99.33	$108	-$0.49	-$0.49	-$1.71	-$0.99	$13.57	$3,303

Source: Energeia Modelling

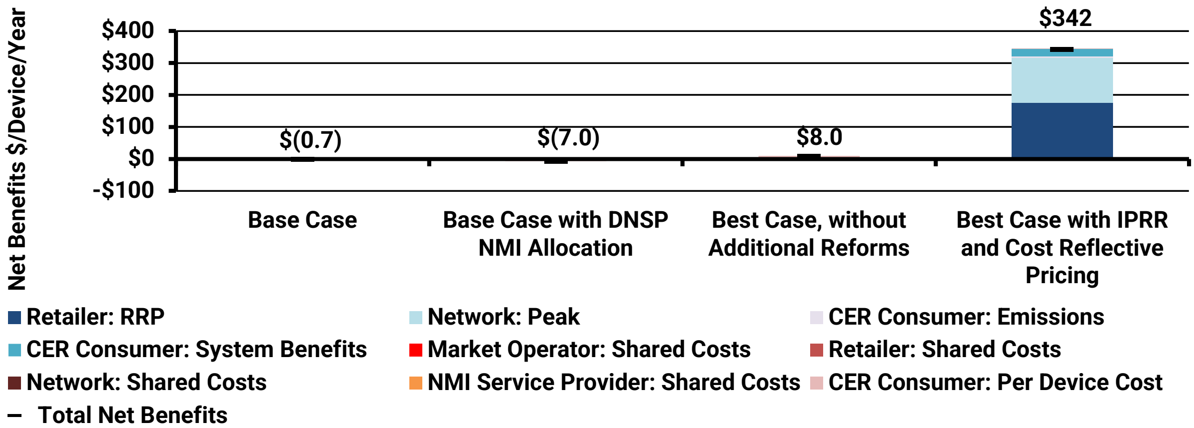
In all CBA scenarios, metering costs are 100% avoidable for large customers, given embedded network framework requirements

Small Customers

In contrast to the large customers, while the small customer CBA shows the Best Case, without Additional Reforms and the Best Case with IPRR and Cost Reflective Pricing scenarios delivering a net positive benefit, the Base Case with DNSP NMI Allocation and Base Case scenarios result in a net negative benefit.

Results of the small customer battery and EV analyses are shown in Figure 12 and Figure 13, respectively.

Figure 12 – Small Customer Battery Net Benefits Against Status Quo



Source: Energeia Modelling

Table 14 – Summary of Small Customer Battery Net Benefits Against Status Quo

Scenario	Net Benefits ($/Year/Device)									
Scenario	Retailer	Network	CER Consumer		Market Operator	Retailer	Network	NMI Service Provider	CER Consumer	Total
Name	RRP	Peak	Emissions	System Benefits	Shared Costs	Shared Costs	Shared Costs	Shared Costs	Per Device Cost	Net Benefits
Base Case	-	-	-	-	-$0.49	-$0.49	-	-$0.99	$1.29	-$0.68
Base Case with DNSP NMI Allocation	-	-	-	-	-$0.49	-$0.49	-$1.71	-	-$4.33	-$7.02
Best Case, without Additional Reforms	-	-	-	-	-$0.25	-$0.25	-	-$0.99	$9.47	$8.00
Best Case with IPRR and Cost Reflective Pricing	$175	$141	$5.66	$22.48	-$0.49	-$0.49	-$1.71	-$0.99	$1.29	$342

Source: Energeia Modelling

In all modelled scenarios, the policy benefits of avoided metering are lower for small customers due to reduced avoided metering benefits based on stakeholder feedback. As a result, not all options tested for small customers result in net benefits in the CBA.

The Base Case scenario delivers a net negative CBA of $0.68 per device per year. This scenario's relatively low costs from NMI service provider-led NMI allocation and management are still larger than the avoidable metering benefits.

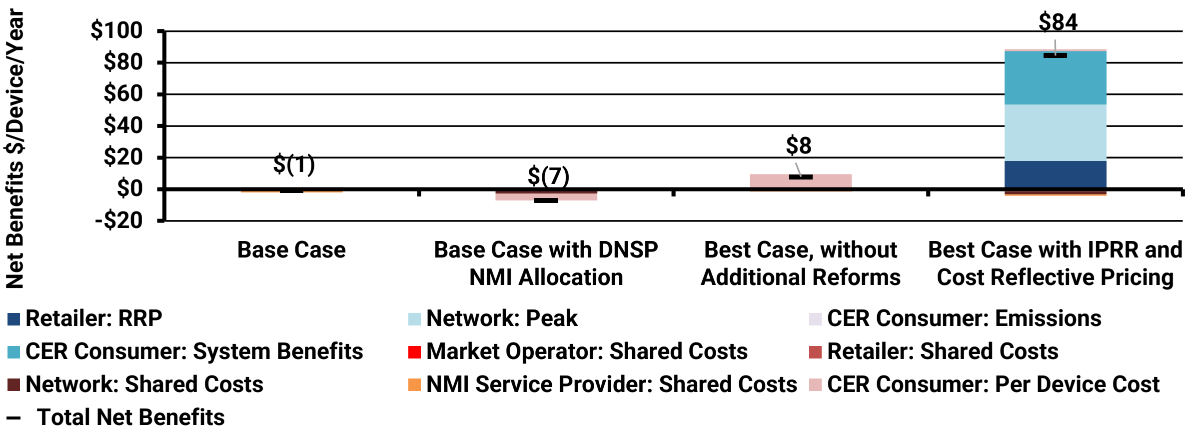
The results show a net negative of $7.02 per device per year under the Base Case with DNSP NMI Allocation scenario. This outcome is lower than the Base Case due to the higher cost assumption of DNSP-led NMI allocation and management.

The Best Case, without Additional Reforms scenario is the first small customer scenario with a net positive CBA delivering $8.00 per device per year. This is mainly due to the lower assumed market operator and retailer shared costs, and higher assumed avoided metering benefits as well as NMI service provider-led NMI allocation and management.

As is the case for the large customer case study, the highest net benefits are seen under the Best Case with IPRR and Cost Reflective Pricing scenario at $342 per device per year. This scenario assumes the same benefits from the CRP and IRRP rule changes per kWh of CER as described under the large customer case study results.

The results for EV modelling are shown in Figure 13 and Table 15 below.

Figure 13 – Small Customer EV Charging Net Benefits Against Status Quo



Source: Energeia Modelling

Table 15 – Summary of Small Customer EV Charging Net Benefits Against Status Quo

Scenario	Net Benefits ($/Year/Device)									
	Retailer	Network	CER Consumer		Market Operator	Retailer	Network	NMI Service Provider	CER Consumer	Total
Name	RRP	Peak	Emissions	System Benefits	Shared Costs	Shared Costs	Shared Costs	Shared Costs	Per Device Cost	RRP
Base Case	-	-	-	-	-$0.49	-$0.49	-	-$0.99	$1.29	-$0.68
Base Case with DNSP NMI Allocation	-	-	-	-	-$0.49	-$0.49	-$1.71	-	-$4.33	-$7.02
Best Case, without Additional Reforms	-	-	-	-	-$0.25	-$0.25	-	-$0.99	$9.47	$8.00
Best Case with IPRR and Cost Reflective Pricing	$17.94	$35.68	-$0.50	$33.72	-$0.49	-$0.49	-$1.71	-$0.99	$1.29	$84.45

Source: Energeia Modelling

A limitation arises from using representative DNSP LRMCs to estimate the costs of additional consumption across the network. Network-wide LRMCs obscure the true range of locational costs and constraints. In practice, in many areas of any given network, there will be many distributors and feeders where the potential benefits from network services exceed the average LRMC. We consider that in many of these areas, the additional benefits will exceed the costs of NMI allocation.

3.2. Breakeven Analysis

Energeia conducted this analysis to determine the level of participation in the rule change that would be required for the benefits of the rule change to outweigh the shared costs to AEMO, retailers, third-party aggregators, networks, and NMI service providers.

3.2.1. Methodology

This section outlines the methodology, inputs, and results for the breakeven analysis. Energeia made these determinations through the following steps:

1. **Calculate the number of flexible devices in consensus view** – Energeia converted the aggregated load flexibility in the NEM forecast by the consensus view of uptake to several devices by utilising assumptions on annual consumption and capacity per device. Consensus uptake is derived from industry papers including AEMO's 2023 IASR[21] and the E3 Demand Response Capabilities report[22]. Note that this is the forecast of all flexible CER, not just flexible CER with its own NMI.

[21] AEMO, 2023 Inputs and Assumptions Workbook (2023), https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en

[22] Equipment Energy Efficiency, Regulation Impact Statement for Decision: 'Smart' Demand Response Capabilities for Selected Appliances (2019), https://www.energyrating.gov.au/sites/default/files/2022-12/smart_appliance_decision_ris.pdf

2. **Determine the costs and benefits of load flexibility for each device with and without a rule change using case studies** – The total costs and benefits of CER flexibility with and without a rule change were derived from the status quo versus policy options, respectively. These options were chosen to allow the full range of network benefits to be considered. The potential costs considered were:
    a. **Shared Costs** – costs that would apply to all customers regardless of flexibility uptake and include the costs of AEMO and retailers upgrading their systems to enable the additional visibility of flexible devices. In the modelling, this was an annual fixed cost, of $5.2 million to both AEMO and retailers respectively, regardless of the level of flexibility uptake, and applies only to the rule change scenario.
    b. **Per-Device Costs** – costs that would apply to each device that was registered to a load flexibility program. Without a rule change, this included the installation of a separate meter on-site to conduct network demand management. With the rule change, this cost is avoided, but the allocation of a NMI to each flexible CER exerts an additional cost. These costs align with those explained in the Rule Change Cost Assumptions portion of Section 3.1.
    c. **Shared Benefits** – system benefits that would be directly accrued to all customers because of networks having visibility of flexible CER loads. Energeia assumed these would be present with or without a rule change but do scale with CER flexibility uptake. The value of these benefits aligns with the Network Management Benefits portion of Section 3.1.
    d. **Per-Device Benefits** – system benefits that would apply to each device that was registered to a load flexibility program. For the scope of this analysis, this was limited to wholesale RRP and network peak cost minimisation. Energeia assumed these benefits would be available with or without a rule change and would be scaled with CER flexibility uptake. These benefits align with the Case Study findings in Section 3.1.
3. **Assign and scale case study results to each flexible CER** – Energeia assigned each CER type considered to a case study according to the size of the customer and the nature of the subload for its energy flow. The per-device benefits calculated by the case studies were scaled to each CER type on a pro-rata basis for the per-device system benefits calculated with the CER Flexibility Optimisation Tool developed for Phase A.

    As shown in the small customer case study (See Section 3.1), the costs associated with establishing a second NMI for small customers under the Low-Benefit scenarios do not exceed the benefits. As a result, Energeia assumed that small customers would not utilise the rule change and were excluded when determining the breakeven uptake for these policy options. They are still however considered as part of consensus flexibility uptake.
4. **Determine breakeven flexibility uptake levels for rule change** – Energeia aggregated the net benefits with and without the rule change according to the consensus view of uptake. Energeia then scaled that level of uptake such that the net benefits were equalised across policy options. Energeia considered this the level of CER flexibility uptake needed for the rule change to be viable.

3.2.2. Inputs

This analysis utilised the inputs and outcomes of the previous modelling, in addition to developing a consensus view of flexibility uptake, which is explained below.

Energeia's breakeven modelling is developed as a net present value (NPV) of costs and benefits of the policy options over a 20-year period, and the device uptake required for benefits to match costs. The discount rate assumed for this modelling was 7%.

Segments Inclusions

The selection criteria for the segments included are outlined in Energeia's Methodology Report[23]. The chosen segments for this analysis include:

- Residential
- Small Commercial
  - Offices
  - Retail
  - Accommodation
  - Warehouses
  - Health
- Large Commercial
  - As above for Small Commercial

It's important to note that upon discussion with the AEMC, industrial customers were deemed out of scope, and were not included in the large commercial segment, as they are already strongly involved in the market for flexible operation (registered loads etc.).

Segments are iterated by each NEM state to account for jurisdictional differences between energy usage by subloads.

CER and Flexibility Uptake Consensus View

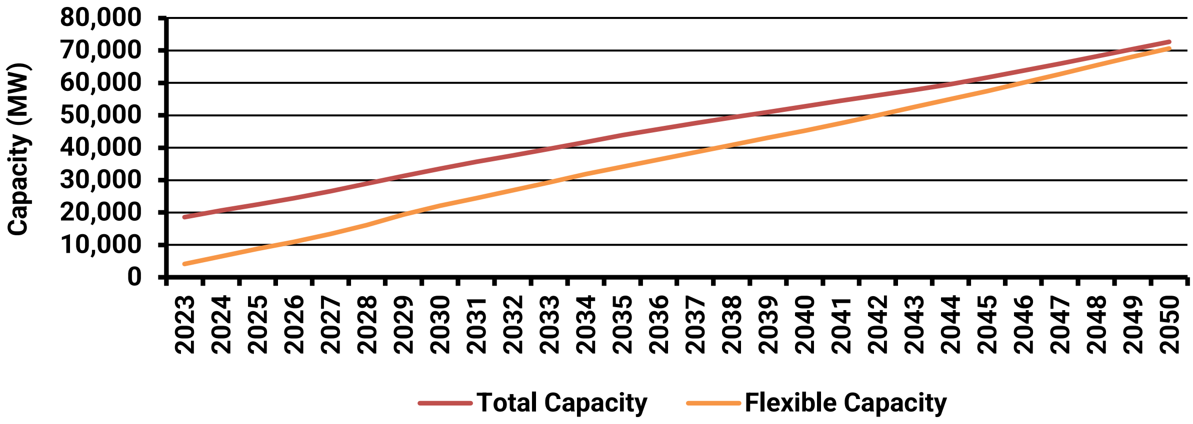
Energeia used the consensus view uptake of CER and flexibility in the analysis to scale the rule change impacts to a NEM-wide level and over the forecast horizon for the included subloads, to ultimately determine the breakeven level of flexibility uptake required for the rule change to be viable. Energeia developed uptake profiles for all consumer segments considered in the analysis. However, for simplicity, the following section reports an aggregation of these values.

The total consumption and flexibility uptake curves for solar and battery technology, shown in Figure 14 and Figure 15 respectively, were collected from AEMO's 2023 IASR Step Change scenario to model flexible capacity uptake to 2050 as a percentage of total capacity. Flexible battery capacity is shown to grow to above 95% of total battery capacity by 2050 due to the number of batteries installed on the network and its inherently flexible load capability, allowing it to be quickly dispatched when called upon. Due to a lack of data on flexible solar capacity, flexible solar uptake was set to follow the flexible battery uptake rate. Energeia considers this assumption to be reasonable as it is expected that smart inverter capabilities will be effectively standard for new and replacement inverters, due to both regulatory changes (e.g., consumer energy resources technical standards) and falling technological costs of smart implementation.

It should be noted that batteries were assumed to be paired with solar PV in the modelling, with any value of dispatched generation from the battery attributed to battery flexibility. Only solar PV curtailment is attributed to solar PV flexibility.

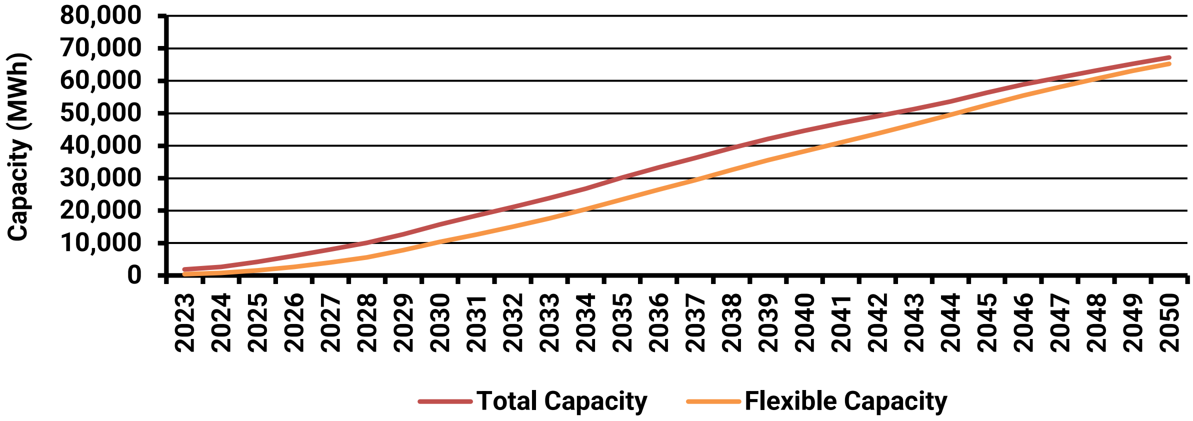
[23] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Methodology Report (2023), https://www.aemc.gov.au/sites/default/files/2023-08/CER%20Flexibility%20Modelling%20Methodology%20Paper%20-%20FINAL.pdf

Figure 14 – Total Solar Capacity vs Flexible Capacity



Source: AEMO IASR (2023), Energeia

Figure 15 – Total Battery Capacity vs Flexible Capacity



Source: AEMO IASR (2023), Energeia

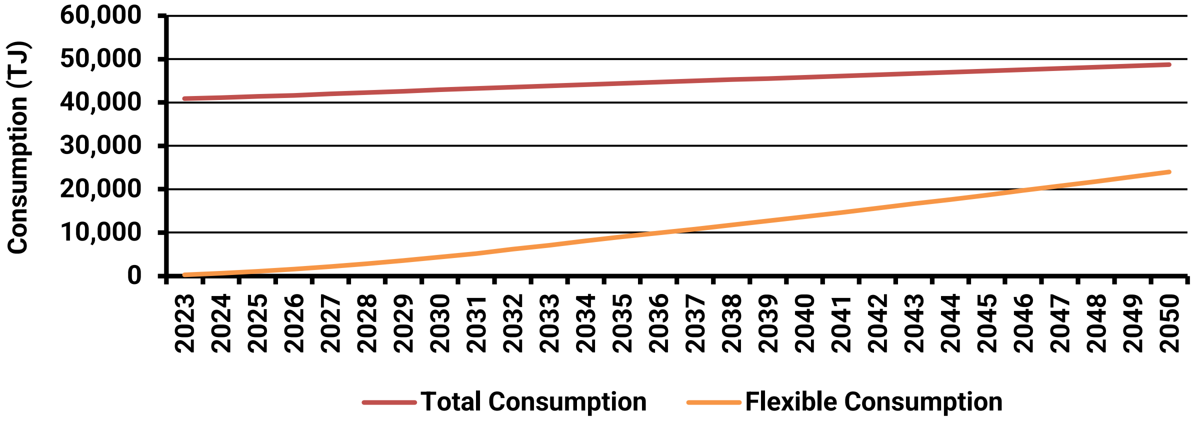
The total water heating consumption, shown in Figure 16, was collected for both residential and commercial premises from the Residential[24] and Commercial Baseline Study,[25] respectively, and modelled out to 2041, with the remaining years being trended to 2050. The flexible water heating uptake rate came from the E3 Demand Response Capabilities report[26] and was modelled to 2036, with the remaining years being trended to 2050.

[24] Energy Rating, Residential Baseline Study for Australia and New Zealand (2022), https://www.energyrating.gov.au/industry-information/publications/report-2021-residential-baseline-study-australia-and-new-zealand-2000-2040

[25] DCCEEW, Commercial Baseline Study (2022), https://www.dcceew.gov.au/energy/publications/commercial-building-baseline-study-2022

[26] Equipment Energy Efficiency, Regulation Impact Statement for Decision: 'Smart' Demand Response Capabilities for Selected Appliances (2019), https://www.energyrating.gov.au/sites/default/files/2022-12/smart_appliance_decision_ris.pdf

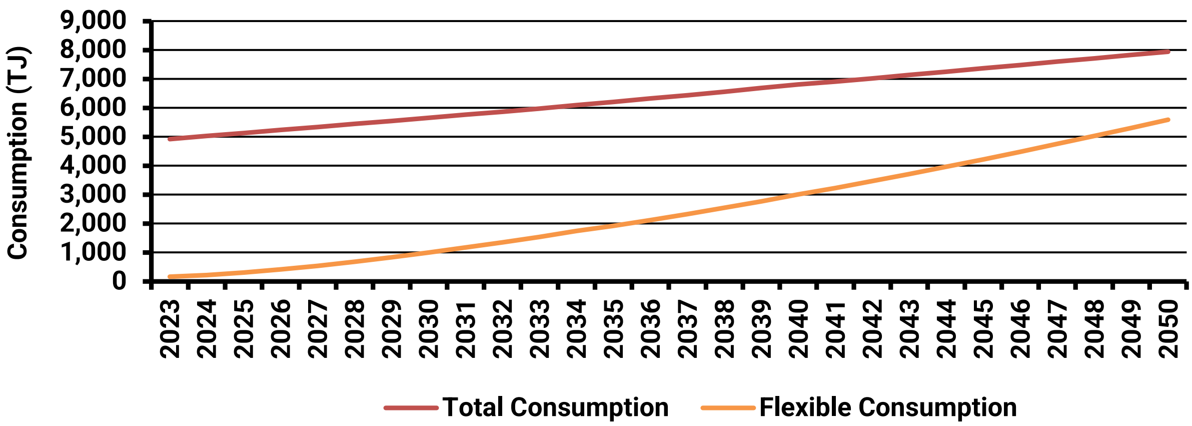
Figure 16 – Total Water Heating Consumption vs Flexible Consumption



Source: Residential Baseline Study (2022), E3 Report (Gov Energy rating) (2019), Energeia

Total pool pump consumption, shown in Figure 17, was collected from the Residential Baseline Study and modelled out to 2041, with the remaining years being trended to 2050. The flexible pool pump uptake rate also came from the E3 Demand Response Capabilities report and was modelled to 2036, with the remaining years being trended to 2050. Pool pump consumption had the highest uptake percentage of flexible load compared to all other technologies. It is one of the easiest to integrate with demand response programs due to its ability to be scheduled to run during off-peak hours. Pool pump consumption was collected only for residential premises.

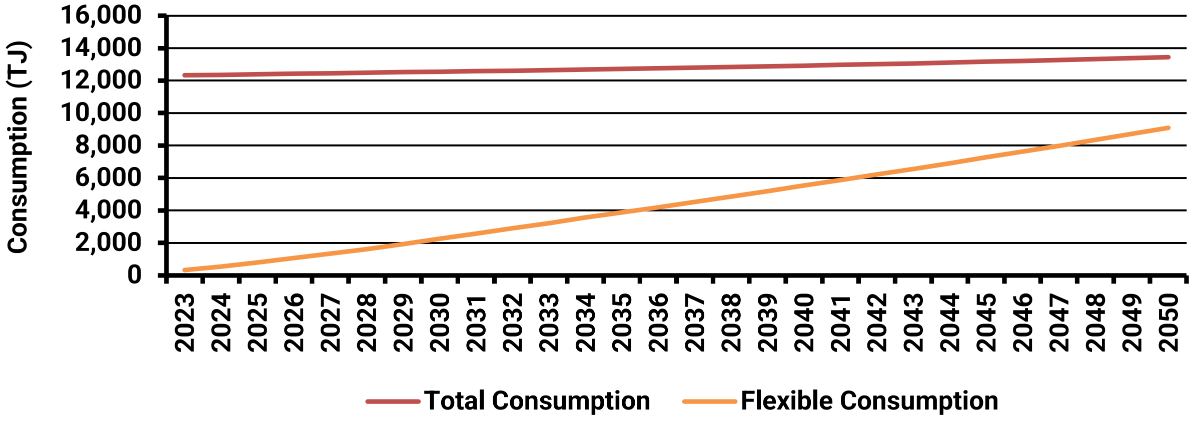
Figure 17 – Total Pool Pump Consumption vs Flexible Consumption



Source: Residential Baseline Study (2022), E3 Report (Gov Energy rating) (2019), Energeia

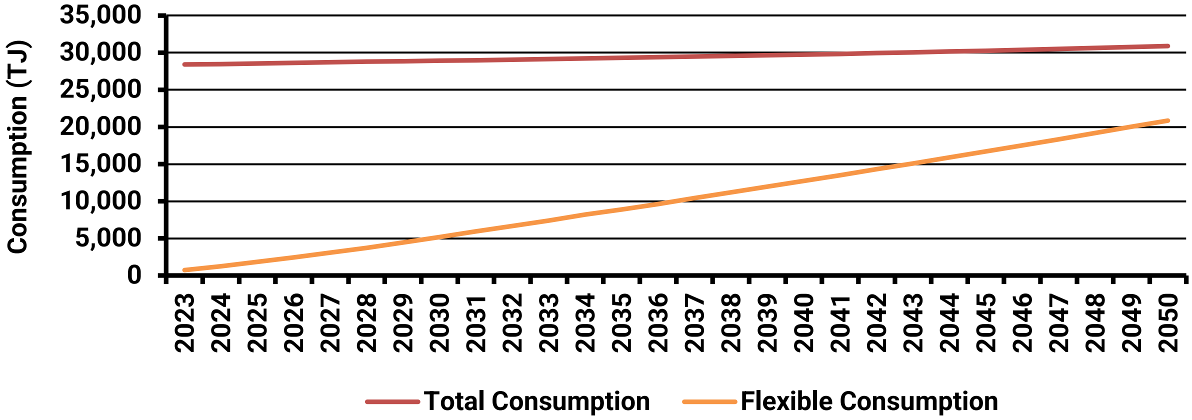
The CER flexibility uptake curves for refrigeration and ventilation consumption, shown in *Figure 18* and *Figure 19*, respectively, were also collected from the E3 Demand Response Capabilities report and modelled out to 2036, with the remaining years being trended to 2050. Total commercial consumption for ventilation and refrigeration was collected from the Commercial Baseline Study to 2041, with the remaining years being trended to 2050. Flexible ventilation consumption is shown to reach around 73% in 2050. Refrigeration was assumed to follow the same uptake curve as ventilation, due to its similar constraints and consumption profile, as well as a lack of publicly available data. These loads were considered only for large commercial premises.

Figure 18 – Total Refrigeration Consumption vs Flexible Consumption



Source: Commercial Baseline Study (2022), E3 Report (Gov Energy rating) (2019), Energeia

Figure 19 – Total Ventilation Consumption vs Flexible Consumption

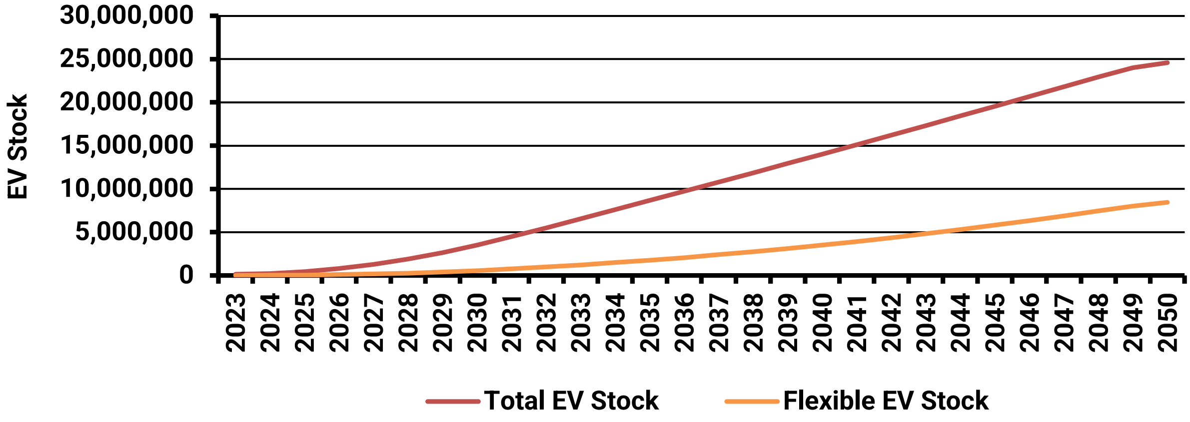


Source: Commercial Baseline Study (2022), E3 Report (Gov Energy rating) (2019), Energeia

The vehicle stock uptake for EVs, shown in Figure 20, was gathered from AEMO's 2023 IASR Step Change scenario to model total and flexible EV stock uptake to 2050. Flexible EV stock reaches only an estimated 36%, with the assumed flexibility uptake derived from the E3 Demand Response Capabilities report. Despite this low percentage uptake in flexible EV stock, a load flexibility study published by the Australian Renewable Energy Agency (ARENA)[27] determined that flexible charging of EVs, whether through deferred charging or V2G services, remained the most utilised source of load flexibility. Note that the IASR/ISP has a 'coordinated charging' cohort of EVs in its forecasts. It does not include a typical usage profile for this since it is flexible.

[27] ARENA, Load Flexibility Study (2022), https://arena.gov.au/assets/2022/02/load-flexibility-study-technical-summary.pdf

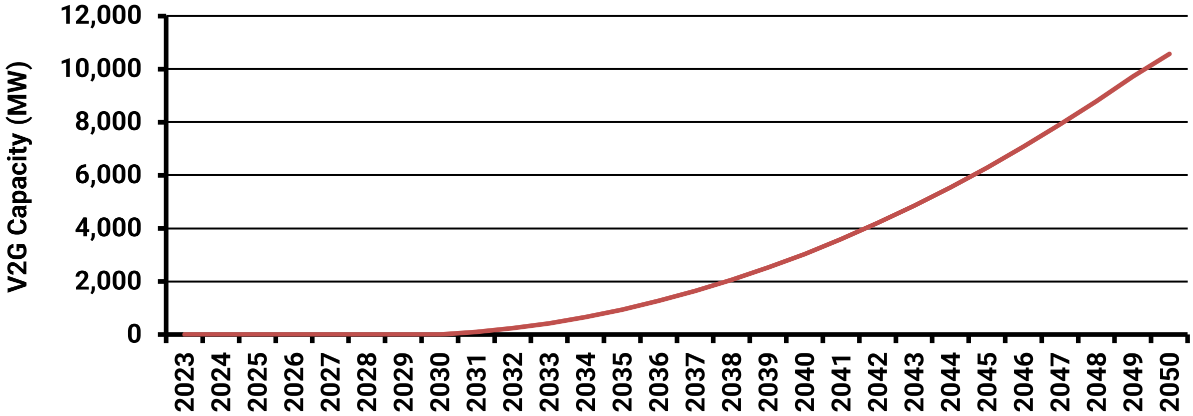
Figure 20 – Total EV Stock vs EV Charging Flexible Stock



Source: AEMO IASR (2023), Energeia

Data on V2G capacity, illustrated in Figure 21 was similarly collected from AEMO's 2023 IASR Step Change scenario, and shows V2G growing from a negligible amount in 2023 to beyond 10GW by 2050. This is assumed to be flexible due to V2G's inherent properties as a dischargeable battery load. By definition, all V2G capacity was assumed to be flexible.

Figure 21 – V2G Total Capacity



Source: AEMO IASR (2023), Note: all V2G capacity is assumed to be flexible

3.2.3. Results

The value of this rule change can essentially be distilled into the net benefit of consumers paying an additional fixed shared cost every year to accommodate AEMO, retailers and networks/NMI service providers upgrading their systems to enable a second NMI using in-device metrology as a result of the rule change, in exchange for avoiding higher per device costs that would exist without the rule change from the need to install meters to undertake network peak management. As the fixed costs do not scale with each additional NMI created but per-device costs and benefits do, a breakeven point exists where the benefits exceed the costs. The analysis below explores this outcome.

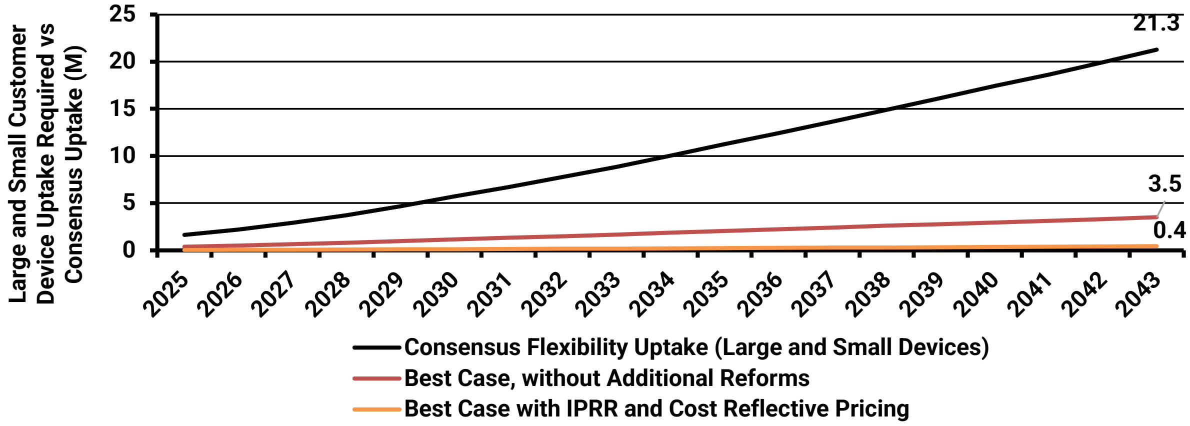
Breakeven Analysis

Energeia used breakeven analysis to identify the level of CER flexibility participation required for the benefits of each CBA scenario to match the costs. If the uptake of CER flexibility via a second NMI were to exceed these levels, the rule change would produce a net benefit. AEMO's 'Consensus' flexible CER uptake scenario is shown alongside as a benchmark.

Energeia notes that our breakeven analysis excludes consideration of second-order benefits, nor does it include benefits from reduced barriers to entry, including greater choice, lower prices, and more innovation.

The breakeven analysis only shows a positive business case when both small and large customers have a net benefit CBA in the case studies shown above. The two scenarios with small and large customer net-positive CBA outcomes are shown in Figure 22 below, assuming proportional uptake.

Figure 22 – Breakeven Flexible CER Uptake Required vs. Consensus (Large and Small Customers)



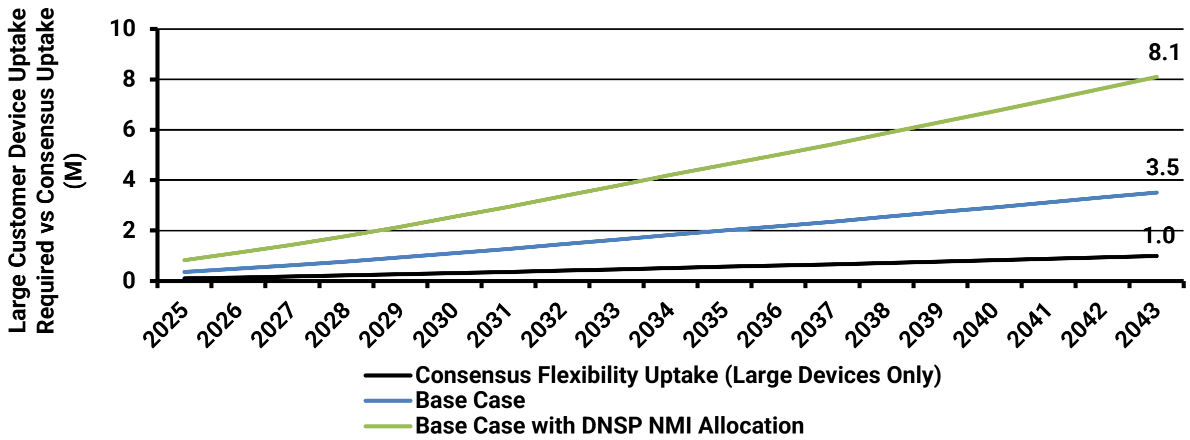
Source: Energeia Modelling, AEMO ISP, E3

Under the Best Case, without Additional Reforms scenario, both large and small customers are considered as both see a positive net benefit under this policy option. An additional 184k devices per year, or 16% of all AEMO forecast flexible CER devices, would need to be enrolled in CER flexibility services to break even, totalling 3.5m over 20 years.

The Best Case with IPRR and Cost Reflective Pricing case again includes large and small customers due to net benefits to both customer types. An additional 23k devices per year, 0.4m over the 20-year modelled lifetime, would need to be enrolled in flexibility and CRP arrangements to break even, or 2% of flexible CER devices.

Without small customer participation, the benefits of the rule change do not exceed costs. The necessary take-up of secondary settlement points exceeds the forecast number of large customer devices. This is shown in Figure 23 below.

Figure 23 – Breakeven Flexible CER Uptake Required vs. Consensus (Large Customers Only)



Source: Energeia Modelling, AEMO ISP, E3

Under the Base Case and Base Case with DNSP NMI Allocation scenarios, only large customers are assumed to participate, as there was a net loss under the small customer case study. The results show that significantly more devices would be required to uptake the policy than are anticipated in the NEM, per the consensus forecasting.

Active vs. Passive Customers

Energeia also analysed the proposed rule change's impacts on active vs. passive customers. Passive customers are defined here as any customers with a NMI that does not have load flexibility or does have it and chooses to not participate in load flexibility programs, which contrasts with active customers, who have flexible CER and are participating in CER flexibility programs.

Ultimately, Energeia and the AEMC determined that the rule change would be expected to impact the outcomes of active and passive customers in the same way, due to retailer behaviour, which prefers to smear some costs across all customers to simplify customer decisions and other operational reasons. Key assumptions made in reaching this conclusion include:

- All costs considered in the scenarios are shared between all customers via their retail tariffs. This includes the shared system upgrade costs and the costs incurred per device for installing new meters at the premises and allocating a new NMI.
- It is common practice for retailers to not directly charge customers for a standard meter installation, but instead to smear the recovery of that cost into their tariffs.
- It is therefore reasonable to assume that in the event of this rule change retailers would smear the NMI allocation cost in the same way to reduce the direct cost to active customers, whom they want to attract to their product.
- Metering providers spoken to by the AEMC indicated that their costs would scale proportionally to uptake, reducing risks associated with the level of participation to pay for the upfront costs of rule change implementation – at least for NMI-related costs.

4. Benefits not Quantified in the CBA

Throughout the analysis, Energeia, the AEMC and feedback from stakeholders have noted several other benefits not quantified in our CBA that would be expected to arise from this rule change and should be recognised.

Certainty for Large Customers

The embedded network framework is currently under review by the AER, which creates a significant regulatory risk for small resource aggregators (SRAs) and retailers that want to offer these products and services using this framework. It is difficult to value this benefit as the extent of the risk is unclear, but it is noted that developing a future framework for use by retailers and SRAs reduces associated regulatory risks for these organisations.

Avoided Costs of Setting up an Embedded Network

The AEMC received feedback from stakeholders participating in embedded networks that they could avoid administration effort under the proposed flexible trading framework. While this saving is not quantified in this report, it is noted that this rule change contributes to a reduced cost for participation.

Increased Competition

The rule change should make it easier for third-party aggregators at small and large customer premises to identify and access benefit streams from CER flexibility, increasing competition, new entry, and choice for end consumers.

Reduced Transaction Costs

A standard, NEM-wide approach to measuring and pricing flexible loads would reduce transaction costs for OEMs related to engaging with each DNSP, FRMP or other flexible load product and service provider to enable CER flexibility. This should enable more providers to enter the market, increasing choice and competition for consumers.

Increased Visibility for Networks

A second NMI could improve distribution networks' potential visibility of flexible devices via standardised market processes. However, we note that it is hard to estimate the value of these benefits, as some networks have indicated that these benefits would be limited (e.g. according to SAPN, visibility provided to a DNSP via device-level visibility does not provide material network benefits compared to site-level visibility.

5. Key Findings, Conclusions and Recommendations

Based on the analysis of the associated costs, Energeia notes that two of the four scenarios are expected to be cost-effective for customers with flexible CER, and therefore capable of breaking even.

Energeia further notes that our breakeven analysis does not consider second-order benefits or benefits from reduced barriers to entry, including greater choice, lower prices, and more innovation. Regardless of whether the rule change is cost-effective on its own, Energeia notes that it will be necessary, but not sufficient, to achieve the full value potential of CER.

Throughout the analysis, Energeia did not identify any modifications to the proposed rule changes that could result in a more optimal outcome.

Longer-term, Energeia has identified the following key regulatory barriers for the AEMC's consideration in future rule changes:

- **Remove barriers to the use of flexible CER for network services:** Flexible CER must be of sufficient size and dependability and be lower cost than alternatives to provide network services. This is more likely to be the case over time, as more CER is deployed, but also more likely where investment incentives are cost-reflective and there is no network capex bias.
- **Remove barriers to using devices for MASS-compliant metering**: Energeia found FCAS to be a key value driver for flexible CER but notes that FCAS currently faces significant barriers to access, mainly metering requirements. Enabling the use of devices for MASS compliance, provided they meet operational requirements, would unlock access to the significant FCAS value stream.
- **Ensure cost-reflective network and retail incentives:** Establishing cost-reflective network and retail prices may allow for more efficient CER utilisation. Current arrangements lead to conflict between retail bill savings and system savings and result in sub-optimal CER utilisation. Cost-reflective pricing would enable 100% flexible CER utilisation and maximise system benefits.
- **Level the playing field for third parties:** Currently, retailers have an upper hand in accessing the value of CER flexibility through existing access to wholesale and FCAS value. Allowing third-party aggregators equal access to these benefits is expected to increase competition amongst CER flexibility service providers, generating additional value for consumers.

Appendix A: Feedback Received on Draft Determination

Table A1 summarises key feedback provided to Energeia's Draft Determination paper, anonymised by provider and grouped by topic.

Table A1 – Summary of Feedback by Topic

Issue #	Topic	Issue	Energeia's Response
1	Consultation	Caution against conducting this analysis without data from retailers	A range of stakeholders provided data to be input into the revised CBA. Energeia notes that no retailer data was received in the consultation period.
2	Consultation	Flag the lack of consultation around input data quality in all areas, particularly around current programs	The AEMC and Energeia undertook further stakeholder engagement post-Draft Determination
3	Cost / Avoided Cost Inputs	Consider the difference between implementing flexible trading arrangements (FTAs) for large vs. small customers	Energeia has varied avoidable metering costs by small and large customer case studies to account for existing differences in embedded network and VPP arrangements
4	Cost / Avoided Cost Inputs	Need to consider additional costs to network of hosting dynamic operating envelopes (DOEs) and flexible pricing arrangements	Energeia has included revised costs to DNSP's covering system upgrade requirements
5	End-to-End Modelling Process - Phase A	Concerned Energeia's method is an overestimation of value as it does not account for diminishing returns	The AEMC has considered a more complex modelling approach and has determined that a simplified, first-order-based approach is appropriate
6	End-to-End Modelling Process - Phase A	Energeia's methodology doesn't consider opportunities and costs from a customer's perspective	Method accounts for the alternative case where consumers minimise their own bill, and also the impact of system optimisation on their bill
7	End-to-End Modelling Process - Phase A	Concerned that the method is double counting/overestimating benefits	Energeia have accounted for the fact that addressing one system benefit has implications for other value streams, so should lower the risk of double-counting
8	Population Inputs	Note the lack of consideration for jurisdictional differences	We are considering unique jurisdictional subloads and costs to the extent the information is in the public domain
9	Selected Case Studies	Want commentary on the difference in consumer outcomes between 'whole-of-home' optimisation and device-by-device optimisation	This rule change aims to reduce costs regarding the unlocking flexibility by avoiding metering costs and opting for lower-cost roles to provide secondary settlement points. Benefits surrounding a change in customer optimisation methods are noted as being dependent on cost-reflective pricing reform.
10	Selection of Subloads	Suggest that Residential HVAC should be re-included as it has a large opportunity (up to 25% during system peak intervals)	The resource was excluded due to the technology's availability and ultimate level of flexibility
11	Selection of Subloads	Flexible load should only consider electric load (referring to Table 3 of the Methodology Report)	Modelling only considers electric load. However, all load was used to determine the scope of analysis since it could be electrified in the future

12	Selection of Subloads	Concerned V2G isn't likely due to car warranties	In the long run, if the benefits are great enough we expect warranty issues will be resolved; we note no warranty issues currently exist
13	System and Customer Inputs	Caution using 2022 prices, suggest taking an average or other historical year or AEMO forecast	Energeia is using 2021 prices. We disagree with averaging as it would smooth hourly price spikes, which are a key driver of the value of flexible resources
14	System and Customer Inputs	Concerned that we haven't considered customer's reluctance to uptake new tariffs incentives	Energeia's breakeven modelling provides a view of the required policy uptake as a portion of the forecasted flexible device uptake

Source: AEMC, Various Stakeholders

Appendix B: Modelling Limitations

In the applied methodology, simplifications were made such that the resulting model would be parsable and tractable. As a result, five key limitations were identified and are detailed below.

It is Energeia's view that the modelling is fit for purpose given the project scope and objective to inform the Australian Energy Market Commission (AEMC) regarding the indicative size of the load flexibility market and to provide an indicative estimate of the required rule change impacts needed to cover the implementation costs.

More detailed and complex modelling is recommended in the future to gain a clearer understanding of the potential benefits on a more granular basis.

Reliance on First Order Impacts

The modelling method implemented contained interactions between consumer behaviour and the wholesale and frequency control ancillary services (FCAS) markets as well as transmission and distribution networks to determine the value of load flexibility. However, no feedback loop was modelled between electricity wholesale market outcomes and load flexibility. In reality, increased flexibility uptake likely would directly alter market outcomes (e.g., change wholesale prices) which would diminish flexibility incentives. Instead, the modelling only captured first-order wholesale market effects of avoided region reference price (RRP), which are expected to be the most significant.

Use of Key Case Studies

The selected consumer case studies were limited in that they did not include an exhaustive list of customer segments and consumer energy resources (CER) technologies for modelling. Instead, Energeia carried out an analysis of end-use load magnitudes by consumer segment and a review of third-party load flexibility assessments to inform the proposed scoping of flexible loads to be included, which Energeia then validated with the AEMC team. This analysis included considerations of the probability of each technology becoming a significant source of flexibility, and the quality of information available. Energeia and the AEMC believe the resulting scope defined through this analysis captures the segments that are the most significant and representative.

Alignment to AEMO's 2023 Step Change Scenario for Adoption and Participation Rates

Another key limitation is the alignment of assumptions to the Australian Energy Market Operator's (AEMO's) 2023 Inputs, Assumptions and Scenarios Report (IASR)[28] in developing a consensus view of load flexibility uptake upon which to base the breakeven analysis. The IASR is not descriptive about its assumed levels of load flexibility uptake, particularly around the uptake of load flexibility in water heating, pool pumps, ventilation, and refrigeration. Energeia has made assumptions about the level of flexibility assumed in the modelling by utilising forecasted activation rates from a 2019 E3 paper.[29] The level of solar photovoltaic (PV) flexibility assumed in the modelling was aligned with the level of behind-the-meter battery aggregation assumed in the IASR. Energeia believes these assumptions align the consensus view of flexibility uptake defined in this analysis to the Step Change scenario in a reasonable way.

Use of Hourly Model Resolution

Hourly profiles were used in modelling despite 5-minute market settlements. Five-minute resolution is important for several reasons including greater accuracy of faster response resources, but in the view of Energeia and the AEMC, it is unlikely to be justified given the indicative nature of this work.

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[28] AEMO, 2023 Inputs and Assumptions Workbook (2023), https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en

[29] Equipment Energy Efficiency, Regulation Impact Statement for Decision: 'Smart' Demand Response Capabilities for Selected Appliances (2019), https://www.energyrating.gov.au/sites/default/files/2022-12/smart_appliance_decision_ris.pdf

Additionally, the resolution was limited by the data and computational limits of the platform (Microsoft Excel).

Broad Network Impact Scope

Energeia undertook modelling of grid impacts on a network-wide basis and assumed a continuous benefit from reducing peak and increasing minimum demand, based on the associated long-run marginal cost (LRMC) for thermal and voltage upgrades. While the impacts may vary within networks, the chosen approach gives a relatively unbiased view of network-wide benefits. The expected impact on the cost-benefit analysis (CBA) accuracy is the potential understatement of low-voltage (LV) and high-voltage (HV) thermal and voltage impacts.

Appendix C: Future Directions

Through the process of assessing the impact of the proposed policy options, Energeia identified key barriers impeding the unlocking of the full potential of load flexibility in the National Electricity Market (NEM). This section contains the full set of modelling scenarios developed by Energeia to show the step change in costs and benefits to be accrued by customers by this reform alongside others.

While the Australian Energy Market Commission's (AEMC's) unlocking CER benefits through flexible trading rule change does not consider changing the process to enable frequency control ancillary services (FCAS) in behind-the-meter consumer energy resources (CER), the current process requires installing a separate market ancillary service specification (MASS) compliant meter at the premises. Energeia's discussions with subject matter experts revealed that this was a costly process which presents a real obstacle to enabling FCAS in consumer devices. Future rule changes could consider allowing the use of MASS-compliant in-device metrology for service providers to participate in the FCAS market.

The AEMC's rule change also does not directly impact the tariffs offered by networks and retailers for consumers and their flexible devices, as networks and retailers will develop new tariffs as required. Energeia's investigation of current battery virtual power plant (VPP) offerings found that VPPs typically are operational only around 53 days of the year on average due to the need to mitigate the impact of orchestrating a customer's behaviour with their retail tariff. The main reason is that system benefits generated from orchestrating loads do not always outweigh the increase in the customer's electricity bill that results from the load being shifted.

Energeia's future directions assessment aims to model scenarios outside of the proposed policy options that can enable CER access to a greater number of value streams, including FCAS, through MASS-compliant metrology standards, as well as network and retail cost-reflective pricing.

Methodology

This analysis is an extension of the economic cost-benefit analysis (CBA) case studies conducted (see Section 3.1) and shows the step change in benefits as incremental changes are made to CER operational behaviour and policy environment. The methodology contained the following similar stages:

1. **Develop future direction scenarios** – Energeia worked closely with the AEMC to develop future direction scenarios
2. **Develop further inputs** – the additional future direction scenarios were attributed to the appropriate implementation costs
4. **Test customer outcomes as a case study** – the scope of this work aligns with the assessment of the policy options through a case study analysis. The case study analysis demonstrates the net costs and benefits for both a representative flexible unidirectional load and bidirectional CER for each customer segment – to evaluate the additional benefits of addressing other barriers to unlocking CER flexibility discussed above.
    a. For Small Customers the same case study loads as the CBA were selected:
        i. Unidirectional load: Electric vehicle (EV) charger
        ii. Bidirectional load: Battery
    b. For Large Customers the same case study loads as the CBA were selected:
        i. Unidirectional load: Ventilation unit[30]
        ii. Bidirectional load: Battery

The following section outlines the development of the future direction scenarios.

[30] A ventilation load (unit or fan) used for air quality purposes, separate from heating or cooling loads

Scenarios

The following scenarios model the impact of increasing the value streams flexible CER can participate in by alleviating barriers to consumers. The scenarios were developed in a stepwise fashion of removing each identified barrier, to isolate the incremental impact of resolving these barriers. The current and future direction scenarios for large and small customers are outlined below.

Large Customers

Energeia has modelled the current status quo operation of a flexible CER operation for large customers. These are as follows:

- **Embedded Network** – the current market arrangement whereby a CER management service provider uses separately metered CER to participate in the wholesale market through the embedded network framework,
- **Embedded Network Providing Network Services** – as per Embedded Network, but includes the provision of demand management (DM) services to the network including installation of an additional meter, which is possible today,

Under the rule change, the following options would be available to large commercial customers:

- **Multiple Financially Responsible Market Participants (FRMPs)** – a retailer VPP, where a flexible CER device is given a National Metering Identifier (NMI), a FRMP, and uses certified in-device metrology, providing standardised data access to authorised participants and enabling use of it by networks to optimise their grids, and
- **Multiple FRMPs Providing Network Services** – the above Multiple FRMPs where the NMI allocated CER device provides DM services to the network.

AEMC's rule change would not affect how service providers enable CER to provide FCAS, meaning that an additional MASS-compliant meter would need to be installed at the premises. It also will not directly influence how retailers or networks price devices.

The future directions analysis considers the following scenarios to unlock further CER flexibility benefits, which can be described as:

- **Embedded Network with FCAS** – the current market arrangement as per Embedded Network, but additionally the CER participates in the FCAS market through an additional MASS-compliant meter,
- **Future Multiple FRMPs with FCAS** – incorporates rule change option as per Multiple FRMPs, and CER is enabled to provide FCAS metrology (assuming compliance with standards),
- **Future Multiple FRMPs Providing Network Services with FCAS** – incorporates rule change option as per Multiple FRMPs Providing Network Services, and CER is enabled to provide FCAS metrology (assuming compliance with standards),
- **Future Multiple FRMPs with Network Cost-Reflective Pricing (CRP) and FCAS** – as per Future Multiple FRMPs Providing Network Services with FCAS, and includes more cost-reflective network pricing for CER load, assessing impact on CER utilisation,
- **Future Multiple FRMPs with Retail and Network CRP and FCAS** – as per Future Multiple FRMPs with Network CRP and FCAS and includes more cost-reflective retail pricing for CER load, assessing impact on CER utilisation.

The policy option design considered for large customers is summarised in Table C1.

Table C1 – Large Customer Rule Change Scenarios Considered

Scenario	Net Benefit Drivers				Market Arrangements				
Name	Increases Competition	Lowers Transaction Costs	Lowers Metering Costs	Lowers Deadweight Loss	FRMPs	NMIs per FRMP	Std. Meter	MASS Compliant Meter	Device Meter
Embedded Network					2^	1	1		1*
Embedded Network Providing Network Services	✓				2^	1	1		
Multiple FRMPs	✓	✓	✓		2	1			1
Multiple FRMPs Providing Network Services	✓	✓	✓		2	1			1
Embedded Network with FCAS					2^	1	1	1	
Future Multiple FRMPs with FCAS	✓	✓	✓		2	1			1**
Future Multiple FRMPs Providing Network Services with FCAS	✓	✓	✓		2	1			1**
Future Multiple FRMPs with Network CRP and FCAS	✓	✓	✓	✓	2	1			1**
Future Multiple FRMPs with Retail and Network CRP and FCAS	✓	✓	✓	✓	2	1			1**

Source: AEMC, Energeia
*Does not meet metrology standard
** Meets MASS requirements
^Using embedded network functionality

Small Customers

Energeia has modelled the current status quo operation of a flexible CER operation for small customers. These are as follows:

- **Current Retailer VPP** – the current market arrangement whereby CER is used by retailers to manage wholesale price exposure without certified device level metrology, nor a standard for accessing it,
- **Current Retailer VPP Providing Network Services** – as per Current Retailer VPP, but includes provision of DM services to the network including installation of an additional meter, which is possible today,

Under the rule change, the following options would be available to small customers:

- **Rule Change VPP** – a retailer VPP, where a flexible CER device is given a NMI and uses certified in-device metrology, providing standardised data access to authorised participants and enabling use of it by networks to optimise their grids, and,
- **Rule Change VPP Providing Network Services** – the above Rule Change VPP where the NMI allocated CER device provides DM services to the network.

The future directions considered within this analysis are:

- **Current Retailer VPP with FCAS** – the current market arrangement as per Current Retailer VPP, but additionally the CER participates in the FCAS market through an additional MASS-compliant meter,
- **Future VPP with FCAS** – incorporates rule change option as per Rule Change VPP, and CER is enabled to provide FCAS metrology (assuming compliance with standards),
- **Future VPP Providing Network Services with FCAS** – incorporates rule change option as per Rule Change VPP Providing Network Services, and CER is enabled to provide FCAS metrology (assuming compliance with standards),

- **Future VPP with Network CRP and FCAS** – as per Future Change VPP Providing Network Services with FCAS and includes more cost-reflective network pricing for CER load, assessing the impact on CER utilisation,
- **Future VPP with Retail and Network CRP and FCAS** – as per Future Change VPP with Network CRP and FCAS and includes more cost-reflective retail pricing for CER load, assessing impact on CER utilisation.

The policy option design considered for small customers is summarised in Table C2.

Table C2 – Small Customer Rule Change Scenarios Considered

	Net Benefit Drivers				Market Arrangements				
Scenario	Increases	Lowers	Lowers	Lowers					
Name	Competition	Transaction Costs	Metering Costs	Deadweight Loss[31]	FRMPs	NMIs per FRMP	Std. Meter	MASS Compli-ant Meter	Devic e Meter
Current Retailer VPP					1	1			1*
Current Retailer VPP Providing Network Services	✓				1	1	1		
Rule Change VPP	✓	✓	✓		1	2			1
Rule Change VPP Providing Network Services	✓	✓	✓		1	2			1
Current Retailer VPP with FCAS					1	1		1	
Future VPP with FCAS	✓	✓	✓		1	2			1**
Future VPP Providing Network Services with FCAS	✓	✓	✓		1	2			1**
Future VPP with Network CRP and FCAS	✓	✓	✓	✓	1	2			1**
Future VPP with Retail and Network CRP and FCAS	✓	✓	✓	✓	1	2			1**

Source: AEMC, Energeia
*Does not meet metrology standard
** Meets MASS requirements

Inputs

This section contains the additional inputs required to determine the outcomes of the future directions.

Rule Change Cost Assumptions

The input costs for small customers and large customers by scenario are shown in Table C3 and Table C4 respectively. The costs are consistent with the initial analysis of policy options from Section 3.1, utilising the Best Case, without Additional Reforms inputs for the status quo, rule change, and future direction scenarios in the tables below, and network system upgrade costs corresponding with network cost-reflective pricing.

[31] Deadweight losses refers to inefficiencies between the cost to serve a customer and the retail rate paid by the customer.

Table C3 – Large Customer Cost Assumptions Including Future Directions

	Costs ($/Year/Device)									
Scenario	**AEMO**	**Retailers**			**Networks**		**OEM**		**NMI Service Provider**	
Name	**System Changes**	**System Changes**	**Std. Meter**	**MASS Compliant Meter**	**System Changes**	**NMI Allocation**	**Certific-ation**	**System Changes**	**System Changes**	**NMI Allocation**
Embedded Network	-	-	$16.38	-	-	-	-	-	-	-
Embedded Network Providing Network Services	-	-	$16.38	-	Negligible	-	-	-	-	-
Multiple FRMPs	$0.25	$0.25	-	-	-	-	Negligible	Negligible*	$0.99	$2.81
Multiple FRMPs Providing Network Services	$0.25	$0.25	-	-	Negligible	-	Negligible	Negligible*	$0.99	$2.81
Embedded Network with FCAS	-	-	$16.38	$81.88	-	-	-	-	-	-
Future Multiple FRMPs with FCAS	$0.25	$0.25	-	-	Negligible	-	Negligible	Negligible*	$0.99	$2.81
Future Multiple FRMPs Providing Network Services with FCAS	$0.25	$0.25	-	-	Negligible	-	Negligible	Negligible*	$0.99	$2.81
Future Multiple FRMPs with Network CRP and FCAS	$0.25	$0.25	-	-	$1.71	-	Negligible	Negligible*	$0.99	$2.81
Future Multiple FRMPs with Retail and Network CRP and FCAS	$0.25	$0.25	-	-	$1.71	-	Negligible	Negligible*	$0.99	$2.81

Source: Energeia
*Assumes internet delivery but not, e.g., a dedicated 4G service

Table C4 – Small Customer Cost Assumptions Including Future Directions

	Costs ($/Year/Device)									
Scenario	**AEMO**	**Retailers**			**Networks**		**OEM**		**NMI Service Provider**	
Name	**System Changes**	**System Changes**	**Std. Meter**	**MASS Compliant Meter**	**System Changes**	**NMI Allocation**	**Certific-ation**	**System Changes**	**System Changes**	**NMI Allocation**
Current Retailer VPP	-	-	-	-	-	-	-	-	-	-
Current Retailer VPP Providing Network Services	-	-	$12.28	-	Negligible	-	-	-	-	-
Rule Change VPP	$0.25	$0.25	-	-	-	-	Negligible	Negligible*	$0.99	$2.81
Rule Change VPP Providing Network Services	$0.25	$0.25			Negligible	-	Negligible	Negligible*	$0.99	$2.81
Current Retailer VPP with FCAS	-	-	-	$81.88	-	-	-	-	-	-
Future VPP with FCAS	$0.25	$0.25	-	-	Negligible	-	Negligible	Negligible*	$0.99	$2.81
Future VPP Providing Network Services with FCAS	$0.25	$0.25	-	-	Negligible	-	Negligible	Negligible*	$0.99	$2.81
Future VPP with Network CRP and FCAS	$0.25	$0.25	-	-	$1.71	-	Negligible	Negligible*	$0.99	$2.81
Future VPP with Retail and Network CRP and FCAS	$0.25	$0.25	-	-	$1.71	-	Negligible	Negligible*	$0.99	$2.81

Source: Energeia
*Assumes internet delivery, not, e.g., a dedicated 4G service

The MASS-compliant meter required to measure FCAS for a device was assumed to be five times as expensive to install than a standard meter based on Energeia discussions with subject matter experts. For small customers, this was downfactored in response to feedback on the Draft Determination, as outlined in Table 3. It is assumed under the rule change scenarios that internal device metrology would be compliant with FCAS requirements, at a negligible cost to original equipment manufacturers (OEMs).

VPP OPERATION HOURS

The following section outlines inputs utilised in modelling the flexibility of CER by characterising current VPP provider strategies for optimising customer VPP participation. Current VPP operation is used to show the impact of rule changes on existing CER behaviour.

To determine an operational limit (i.e., maximum days of the year of flexible device control by the VPP/FRMP) for modelling CER flexibility, Energeia researched 16 available residential battery VPP offers in Australia and narrowed them down to a selection of offers that included explicit annual operation limits or estimates. The operational limit taken forward was determined based on the average of this selection, as shown in Table C5. Note that depending on the provider, these limits were either defined in units of energy (kWh) or days of the year. The analysis assumed that the battery would cycle once per day of operation, allowing for a conversion of all operational limits to days of the year.

Table C5 – VPP Annual Operation Limits

VPP Provider	Max Annual Operation (days/year)	Source
origin	20	https://www.originenergy.com.au/solar/batteries/origin-loop-partner-battery-offer/
nectr	50	https://nectr.com.au/news-and-resources/everything-you-need-to-know-about-vpps/
ShineHub	104*	https://shinehub.com.au/virtual-power-plant/
simply energy	41	https://www.simplyenergy.com.au/residential/energy-efficiency/simply-vpp/new-solar-battery
TESLA	50	https://www.tesla.com/en_au/tep
AVERAGE	53	

Source: Solar Quotes (2023), Origin "Loop" (2023), Nectr VPP (2023), ShineHub VPP (2023), SimplyEnergy "Simply VPP" (2023), Tesla "Energy Plan" (2023), Energeia
*Based on ShineHub's estimate of two VPP events per week

Energeia took forward the 53 operational days per year as an input to limit the number of days of flexible operation in the rule change scenarios. A flexible operational limit is needed to reflect a reasonable market outcome, which acknowledges that the flexible operation of CER devices may compete with consumer retail bill minimisation interests.[32]

In the modelling of future policy, this operational limit is no longer applied, given the assumption that CER flexibility is completely unlocked.

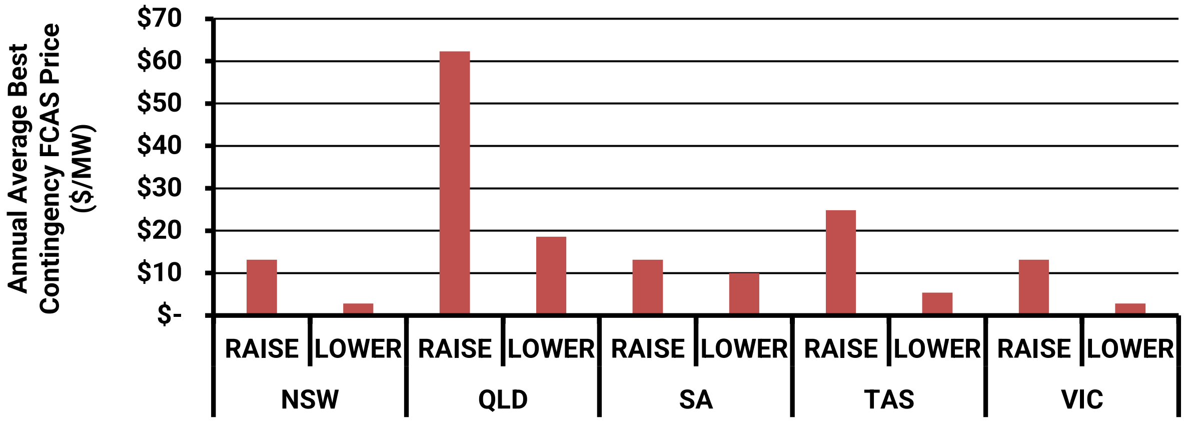
FCAS COSTS

Energeia used contingency FCAS pricing at 1-hour intervals in the model to value the impact of load flexibility by using the spare capacity of a CER at a given interval to make it available to the highest-valued market.

Energeia collected prices by state for the 6-second, 60-second, and 5-minute contingency, raise, and lower markets. The highest raise and lower prices across these markets were calculated for each 30-minute interval by state, as the best use-case option for FCAS capacity. Figure C1 shows the annual average of these best prices by state.

[32] Note that there are some available VPP offers which are allowed greater access to customers' batteries based on risk appetite and rewards available

Figure C1 – Annual Average Best Contingency FCAS Price by State (2021)



Source: AEMO (2021), Gorman et al. (2018)

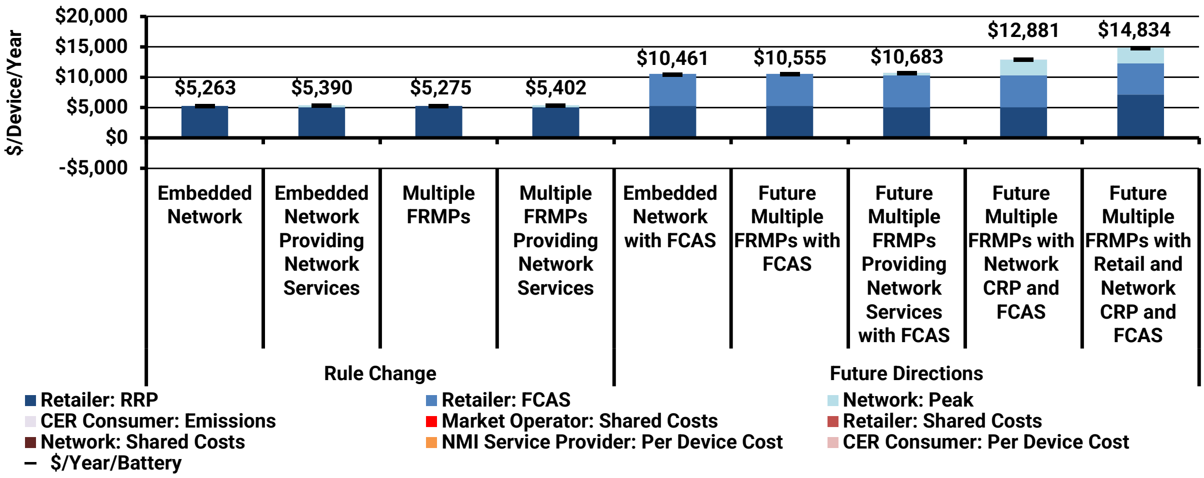
Results

This section outlines the results of the future directions analysis.

Large Customers

The large customer battery case study results, including future directions, are shown in Figure C2 below. All future directions policy options increase the benefits per device per year through the additional value streams. The value of retail and network cost-reflective pricing is modelled to be $4,373/battery/year in estimated net benefits when comparing the net benefits across scenarios. This consists primarily of benefits from reduced metering costs and improved cost reflectivity of retail and network pricing enabling greater utilisation of load flexibility.

Figure C2 – Large Customer Battery Case Study

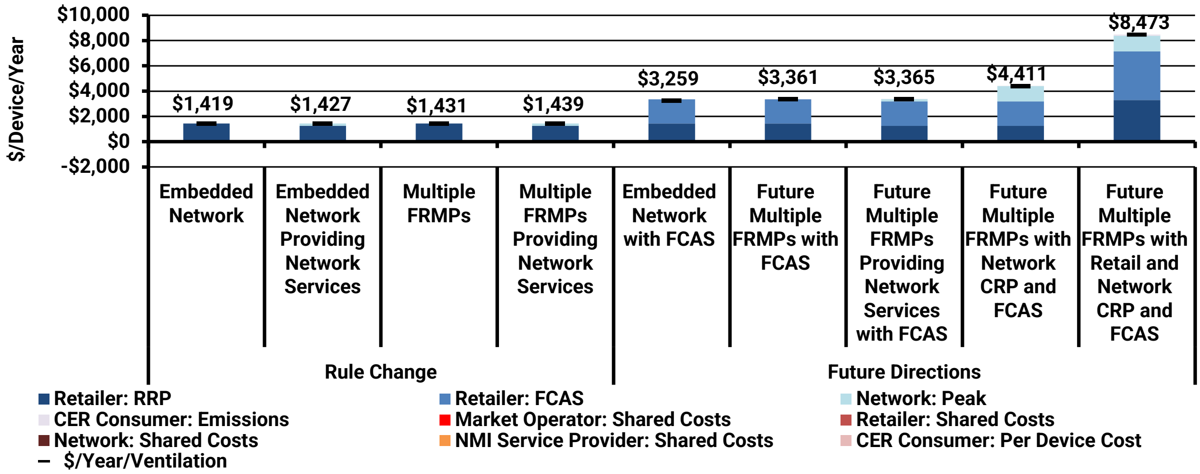


Source: Energeia

Note: Red = Cost; Blue = Benefit; Network: Peak = Operation of CER to minimise peak demand impacts; Network: Management = Network usage of data enabled through CER device metrology provision to network operators

The future direction policy options primarily seek to expand CER flexibility by unlocking key barriers in the energy market. This includes FCAS market participation and wider consumer choice for network and retailer tariffs. Similar results were observed for unidirectional loads such as ventilation, as shown in Figure C3

Figure C3 – Large Customer Ventilation Case Study



Source: Energeia

Note: Red = Cost; Blue = Benefit; Network: Peak = Operation of CER to minimise peak demand impacts; Network: Management = Network usage of data enabled through CER device metrology provision to network operators

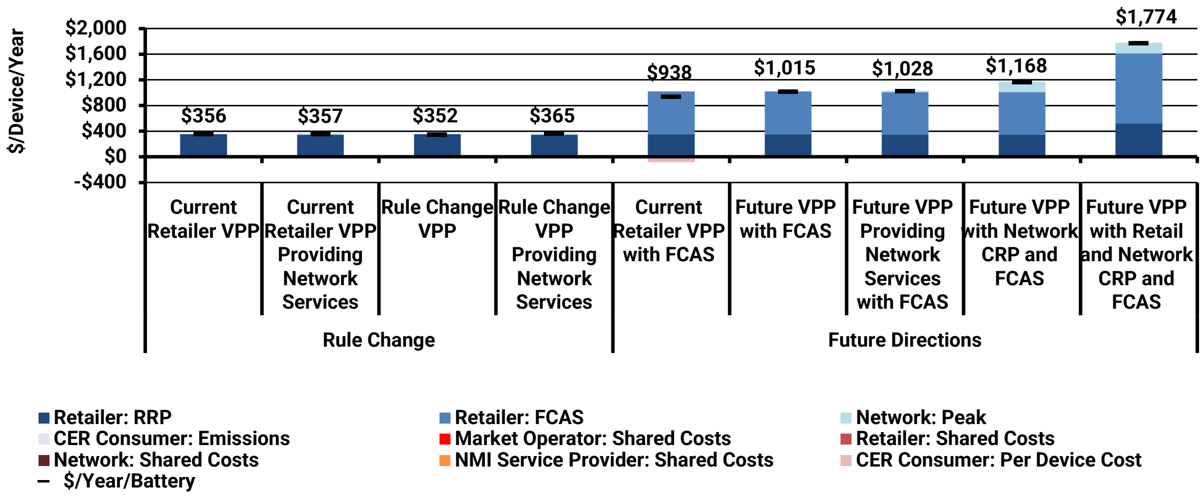
In the case of ventilation, Future Multiple FRMPs with Retail and Network CRP and FCAS accrue $5,215/ventilation/year in estimated net benefits compared to Embedded Network with FCAS, again driven by reduced metering costs and improved cost reflectivity of retail and network pricing enabling greater utilisation of load flexibility.

The other options follow benefit trends similar to the battery device policy options, with Future Multiple FRMPs with Network CRP and FCAS seeing similar but lower retailer costs due to the lack of retailer cost-reflective pricing, and the remaining future directions options generating decreasing levels of benefits due to the lack of both network and retailer cost-reflective pricing and increased metrology requirements.

Small Customers

The small customer battery case study results in Figure C4 show that Future VPP with Retail and Network CRP and FCAS would generate the greatest additional benefits: $837/battery/year in estimated net benefits compared to Current Retailer VPP with FCAS. This consists primarily of benefits from reduced metering costs and improved cost reflectivity of retail and network pricing enabling greater utilisation of load flexibility.

Figure C4 – Small Customer Battery Case Study



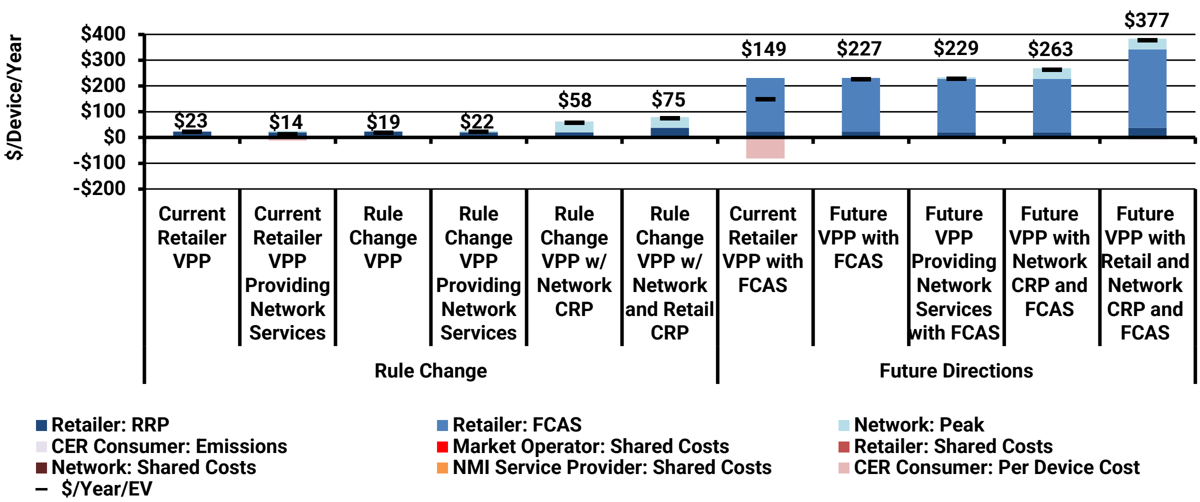
Source: Energeia
Note: Red = Cost; Blue = Benefit; Network: Peak = Operation of CER to minimise peak demand impacts; Network: Management = Network usage of data enabled through CER device metrology provision to network operators

The remaining future directions policies have decreasing benefit streams compared to Future VPP with Retail and Network CRP and FCAS because of their metering configurations and out-of-scope policy settings, which have varying levels of cost categories and flexible market arrangements. Future VPP with Network CRP and FCAS have benefit streams similar to those of Future VPP with Retail and Network CRP and FCAS, as its cost-reflective network pricing allows for greater use of load flexibility without any trade-offs from the consumer's perspective; however, exhibits lower retailer benefits due to its lack of retailer cost-reflective pricing.

Future VPP Providing Network Services with FCAS yields even lower benefits because it lacks any type of cost-reflective pricing, while Current Retailer VPP with FCAS has the least benefits due to its costly metrology requirements, despite having slightly higher retailer benefits than the comparable options with the additional provision of network services and splitting of the VPP usage time between several value streams lowering the absolute allocation to retailer benefits. The minor cost difference between Future VPP with FCAS and Future VPP with FCAS is due to the additional metering cost, as the Future VPP with FCAS option does not require a separate MASS-compliant meter for FCAS participation.

Similar results were observed for unidirectional loads, including small customer EV charging, as shown in Figure C5.

Figure C5 – Small Customer EV Charging Case Study



Source: Energeia
Note: Red = Cost; Blue = Benefit; Network: Peak = Operation of CER to minimise peak demand impacts; Network: Management = Network usage of data enabled through CER device metrology provision to network operators

In the case of EV charging, Future VPP with Retail and Network CRP and FCAS yields an additional $228/EV/year in estimated net benefits compared to Current Retailer VPP with FCAS, again driven by reduced metering costs and improved cost reflectivity of retail and network pricing enabling greater utilisation of load flexibility.

The other options follow benefit trends similar to the battery device policy options, with Future VPP with Network CRP and FCAS exhibiting similar but lower retailer costs due to the lack of retailer cost-reflective pricing; Future VPP Providing Network Services with FCAS, Future VPP with FCAS, and Current Retailer VPP with FCAS generate decreasing levels of benefits due to the lack of both network and retailer cost-reflective pricing and increased metrology requirements.

Energeia's mission is to empower our clients by providing evidence-based advice using the best analytical tools and information available

Heritage

Energeia was founded in 2009 to pursue a gap foreseen in the professional services market for specialist information, skills and expertise that would be required for the industry's transformation over the coming years.

Since then, the market has responded strongly to our unique philosophy and value proposition, geared towards those at the forefront and cutting edge of the energy sector.

Energeia has been working on landmark projects focused on emerging opportunities and solving complex issues transforming the industry to manage the overall impact.

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