



SolarCitizens

A community voice for cleaner energy and transport

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Putting flexibility first

Submission on the AEMC's Electricity Network Regulation Review (ENRR)
Package 2 consultation paper

From Solar Citizens

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Executive Summary and recommendations

As the AEMC consultation paper states, transmission and distribution charges comprise between 33 and 48 per cent of electricity bills, so how distribution network revenue is set is one of the largest determinants of what households pay.

This submission is confined to discussing distribution network revenue given this is where consumer energy resources (CER) connect and can substitute for network infrastructure, but many of the principles are likely to also apply to transmission network revenue.

The Commission has told submitters that its starting point "does not rule out ambitious and substantive reform", and that it will consider reform "where a strong evidence base indicates that consumers stand to benefit".

We now have a situation where consumers are potentially paying twice, once for the solar, batteries, hot water systems, air conditioners, EVs and other devices they have already bought, and again for network capacity built to provide services those devices could, in most circumstances, have supplied at lower cost.

Solar Citizens is calling on the AEMC to make flexibility the first option that a distribution network tests. Before proposing capital expenditure to relieve a forecast or existing constraint, a distribution network (DNSP) should have to establish that consumer energy resources cannot relieve it at lower cost and publish that comparison. EU law requires regulatory arrangements that enable and encourage distribution operators to procure flexibility where it cost-effectively avoids network upgrades, and generally requires transparent, non-discriminatory, market-based procurement. In 2024/25 British distribution networks procured 9GW of distribution flex from household, business and utility resources.

Changing the process by which revenue is set is equally important. Solar Citizens recommends assessing all thirteen distribution networks at once, every two years, on a published formula and a common data schedule. This shortens the forecast horizon to something more easily forecastable, reduces the resourcing asymmetry and makes comparison between distribution networks possible in a way that thirteen separate revenue determination timetables prevent.

A duty to test flexibility only works if there is no bias by type of expenditure. Today a distribution network earns a return on an asset (capex) for its life and recovers an operating expense (opex) as an expense only in the year it is incurred, so the two options are not commercially equivalent no matter how they are assessed. Solar Citizens recommends the use of total expenditure with the split between fast and slow money set administratively by the regulator, reducing the preference arising from different capitalisation treatment. Aligning the sharing rates of the Capital Expenditure Sharing Scheme (CESS) and the Efficiency Benefit Sharing Scheme (EBSS) is not a substitute. Menu regulation should also be adopted, to discourage inflated forecasts, subject to the AER's independent cost assessment and careful calibration.

Neutrality is a starting condition, but it is not the same as changing financial motivation. DNSPs also need a real share of the money they save consumers by not building, which is what an Avoided Network Cost Payment could provide in place of the Demand Management Incentive Scheme (DMIS). At least two further rewards should sit beside it: a decarbonisation incentive valuing measured contribution to electrification at the value of emissions reduction, and innovation funding held outside the expenditure incentive arrangements, allocated competitively and published in full, including where projects fail.

The regulated asset base (RAB) should also be able to move in both directions, so that over-building can be assessed by ex post (after the expenditure) review and stranded assets can be written down rather than recovered in full from remaining customers, with the AEMC to determine the definition of stranding and the sharing method.

Finally, the Australian Energy Regulator (AER) needs to be accountable for the additional discretion these changes would give it, through published program logic, measured outcomes and independent evaluation.

Solar Citizens' recommendations are set out below:

1. **Impose a flexibility-first procurement duty.** Before proposing capital expenditure to relieve a constraint, a DNSP must test whether consumer resources could relieve it at lower cost and publish the comparison. Article 32 of Directive (EU) 2019/944 supports cost-effective flexibility procurement, but the published, priced comparison proposed here would be an additional Australian requirement. Give that duty effect by requiring a priced non-network counterfactual with every material augmentation proposal. (Q2, Q5, Q6, Q9)
2. **Assess all distribution networks at once, every two years,** on a published formula and a common data schedule — simultaneity as Ofgem does it, frequency double the rate Norway does it — with a defined route for a distribution network with a genuinely exceptional transformation programme to seek a longer, more closely examined determination. (Q2)
3. **Change how distribution network revenue is set**
 - 3.a. **Set the capitalisation share administratively,** applying a predetermined split of total expenditure between fast and slow money, so that a network's return does not depend on whether it meets a need with an asset or a service. This is the central measure for levelising capex and opex, for creating a level playing field for CER/DER. Aligning CESS and EBSS sharing rates is not a substitute for it. (Q5)
 - 3.b. **Adopt menu regulation for expenditure forecasts.** Before each determination, the AER would publish a menu of spending options. Each option pairs a spending level with a reward rate, set so that the more a DNSP claims it needs to spend, the smaller its share of any savings. A suitably designed menu could give DNSPs a financial reason to make more accurate forecasts, while the AER would still need independent cost assessment, calibration and checks against strategic selection (Q2, Q3)
4. **Change how distribution networks are rewarded**
 - 4.a. **Develop an Avoided Network Cost Payment to replace the DMIS,** taking New York's Orange and Rockland incentive as a design comparison. That incentive starts at 30 per cent of the estimated net benefit of a non-network option, adjusts for 50 per cent of any cost overrun or underrun, and has a zero floor and a ceiling of 50 per cent of the initial net benefit. The unamortised incentive balance earns the utility's approved weighted average cost of capital. The Australian payment rate and the benefits included in its calculation would need to be determined separately. (Q5)

- 4.b. **Introduce a Decarbonisation Incentive Scheme** valuing measured contribution to electrification at the value of emissions reduction as an earnings-affecting mechanism applied through the reset rather than a published scorecard, calibrated to reward orchestrated electrification that lands new load in existing headroom. (Q1, Q5, Q12)
- 4.c. **Fund network innovation outside the expenditure incentive arrangements**, through a dedicated fund allocated competitively across DNSPs, with a test directing funding to projects unlikely to benefit the DNSP itself, no repayment where a project does not pay off, mandatory publication including of failures, and no proprietary advantage from consumer-funded innovation. New Zealand's DPP4 arrangements are worth examining as a design comparison. (Q8)
5. **Allow for changes in the RAB in more circumstances**
- 5.a. **Make ex post review capable of addressing over-building.** Amend the National Electricity Rules so the AER can initiate a review where an augmentation is materially and persistently under-utilised relative to the forecast that justified it, even if the DNSP did not exceed its capital expenditure allowance. Under-utilisation should trigger scrutiny, not automatic exclusion. The AER should assess whether the investment was prudent in light of information reasonably available when the decision was made, including whether the DNSP properly compared it with a credible, priced non-network option. Where expenditure fails that test, the Rules should permit the AER to exclude the imprudent amount from the regulated asset base. The AER's guidelines should then specify the evidence and review process. (Q9)
- 5.b. **Amend the Rules to allow stranding with shared costs**, as the ACCC recommended in 2018 and directed to this Commission: the Rules should expressly allow a process by which network assets may be stranded and the cost of that stranding shared between users and networks, with the AEMC to determine the definition of stranding and the sharing method. The two remedies address different cases: an imprudent investment and an asset stranded despite a prudent original decision. Ex post review deals with an investment the DNSP should not have made, while stranding deals with an asset that is no longer needed. Without a no-fault route, every write-down argument has to be run as a finding of imprudence against a plan the AER approved. (Q9)
6. **Make the AER accountable for the powers this Review would give it:** program logic evaluation of its revenue and rate of return decisions under the Commonwealth Evaluation Policy, a duty to respond substantively to stakeholder submissions, and independent periodic review of its economic regulation performance. Accountability should extend to the outcomes of the Rate of Return Instrument. The AER should publish each network's actual and allowed profit in dollars annually, explain material differences and feed the evidence into the next instrument. (Q2, Q11)

The most important proposition in this submission: flexibility first

This Solar Citizens submission largely follows from the ‘flexibility first’ sequencing principle for distribution network decision making and revenue first articulated in Great Britain. ‘Flexibility first’ says that before a distribution network builds capacity, it should have to establish that the same job cannot be done more cheaply using the distributed energy resources (DER: generation, storage and flexible demand) that consumers have already paid for and its revenue should be weighted accordingly. It recognises the inherent consumer benefits of drawing on assets in people’s homes and businesses to alleviate network congestion. The asset owners are paid for the flexible use of their assets, and all bill payers benefit from lower costs due to the reduced capital expenditure on new or expanded infrastructure.

There are currently over 4.5m rooftop solar installations and more than 800,000 small-scale battery installations in Australia ([Clean Energy Regulator](#)). Consumers financed that fleet, as well as hot water systems, air conditioning units, pumps and other devices in machines in homes and businesses. When a network builds capacity that duplicates what the fleet of Consumer Energy Resources (CER) could have supplied, consumers pay for the same service twice. More formally, consumers can pay for avoidable network capacity if a DNSP builds to meet a constraint that contracted consumer flexibility could have relieved more cheaply at that location and time.

The size of savings being forgone by not utilising CER/DER has been estimated repeatedly in Australia, by different parties, using different methods, over nearly a decade, and the answers have all been large. The ENA-CSIRO Electricity Network Transformation Roadmap concluded in 2017 that orchestration of DER would avoid \$16 billion of network infrastructure investment by 2050, reduce cumulative total system expenditure by \$101 billion, and see networks paying consumers more than \$2.5 billion a year for grid support services by 2050, with network charges 30 per cent below 2016 levels ([Energy Networks Australia and CSIRO, *Electricity Network Transformation Roadmap*](#)). In 2021 Baringa's modelling found that proper orchestration could avoid \$11 billion of network infrastructure investment by 2040 ([McConnell and Kuiper, p.33](#)), and IEEFA's assessment put the combined network and generation benefit at \$19 billion by 2040, the generation component drawing on NERA's estimate of \$8 billion in avoided generation and storage cost ([IEEFA](#)).

More recent modelling undertaken by [Energeia for the AEMC](#) estimated that fully unlocking the flexibility of forecast CER could deliver \$45 billion in net present value benefits to 2050. Energeia estimated the network component using avoided network costs and AER-approved estimates of long-run marginal cost. This component represented 12 per cent of the total benefits in net present value terms—implying approximately \$5.4 billion in avoided network costs to 2050. None of these studies anticipate the enormous BTM (behind the meter) battery uptake of the last 15 months. This means every one of these estimates was made with a smaller consumer-owned fleet of DER than exists today.

Britain has moved from estimating the value of flexibility to scaling distribution flex. Great Britain began a major reform of economic regulation for energy networks through Ofgem’s RPI-X@20 review, culminating in October 2010 in the decision to replace the long-standing RPI-X price-control framework with RIIO “Revenue = Incentives + Innovation + Outputs”. RIIO retained incentive-based revenue regulation, but shifted it towards longer-term, output-led regulation, stronger stakeholder engagement, explicit innovation support, and mechanisms to manage

uncertainty. The approach was designed to make monopoly network companies more responsive to decarbonisation, changing user needs and the need for smarter networks, while preserving pressure for efficient delivery and value for consumers. It emphasised flexibility, but in the initial years, take up was slow. For example, contracted volume for the first reported year in 2018 was 116 MW ([Energy Networks Association \(ENA\), Insights Forum: Open Networks, 24 July 2024, slide 37](#)).

For RIIO-ED2—the five-year electricity-distribution price control for which the method was set in 2020—Ofgem established a ‘flexibility first’ approach as part of ‘enabling a decentralised, decarbonised and digitalised energy system’. Ofgem stated, ‘we expect DNOs [Distribution Network Operators] in the first instance to use flexibility to address network constraints, while ensuring networks do not become blockers to an uptake in low carbon technologies’ ([RIIO-ED2 Methodology Decision: Overview](#)).

In 2024-25, British DNOs contracted a record 9 GW of flexibility of 31 GW tendered, and harnessed 22 GWh — a three-fold increase on the previous year — which the Energy Networks Association (British ENA) estimated saved bill payers more than £300 million in 2024, with more than £3 billion projected over the following three years ([Energy Networks Association](#)). The longer-run system value is larger again: the Carbon Trust's assessment of flexibility across heat, transport, industry and power in Great Britain found net savings of up to £16.7 billion a year by 2050 ([Carbon Trust, Flexibility in Great Britain](#)).

Payments to British battery owners vary considerably by location, product, availability period and actual dispatch: recent network examples range from availability payments of £1.31–£18.54 per MW per hour to utilisation payments of £60–£3,584 per MWh. National Grid DSO reported that providing 1 kW of flexibility for a four-hour short-term event could earn £14.34, while UK Power Networks currently advertises maximum utilisation prices of £600/MWh for demand reduction and £850/MWh for demand turn-up. These are gross service payments, not guaranteed annual earnings received by each battery owner.

The Commission may reasonably ask whether flexibility-first is deliverable at scale in Australia. The British example shows that the market will likely need time to scale and mature and Areti, the distribution network for Rome, shows that the scale-up can be planned for. Facing peak demand rising from 2.1 GW in 2022 to a forecast 3.3 GW by 2032, with those peaks occurring for roughly 1,000 hours a year, Areti decided to reinforce its network to 2.6 GW and to meet the remaining 700 MW — about 250 GWh — through procured flexibility. Full reinforcement was estimated at €1,100 million. The combined approach is estimated to cost €480 million of reinforcement plus €130 million of flexibility, and Areti estimates it will reduce total annual expenditure by 45 per cent over this time period ([EU DSO Entity, Report on Distributed Flexibility Practices](#)). Areti is so far managing 22 MW of flex from 1,300 customers and 18 service providers (aggregators), with a constant growth of the market liquidity in the last two years. Flex takes time to scale, but Australia's rapid growth in BTM battery uptake with the majority of these batteries being ‘VPP ready’ should enable fast scaling with the right regulation.

Solar Citizens believes ‘flex first’ is an important solution to the question many people have been asking, ‘why are battery owners not signing up to VPPs?’. It could provide substantial revenue to battery owners in network constrained areas and substantially reduce the cost of network augmentation that might otherwise be required with electrification.

Three consequences of a ‘flex first’ proposition run through the answers to the consultation paper below. Networks need a requirement to test flexibility before building, not an encouragement. They need to earn a real share of the money they save consumers by not building, which is a different instrument from the Demand Management Incentive Scheme (DMIS). And the return on capital has to cease being the only part of the revenue determination that compounds.

Question 1: Prioritisation framework for the Review

Solar Citizens supports the proposed assessment criteria and particularly supports outcomes for consumers being listed ahead of market efficiency. Including emissions reduction and the principles of good regulatory practice are also supported.

We propose one addition to the criteria, risk of structural lock-in. A decision taken in 2027 can foreclose cheaper pathways for the following two decades. The greatest economic risk to consumers in a transition moving this fast is unlikely to be the issue that looks most material today. Perhaps data centres will be a large risk in 2037 and beyond, but with so much technological change, the future is very difficult to forecast.

The economic regulation of distribution networks was designed for a one-way system and has not been fundamentally revisited since; what this Review settles will shape investment into the 2050s. We recommend an explicit criterion: whether an option preserves or forecloses future options, assessed over at least thirty years.

For the same reason we caution against giving too much weight to implementation feasibility. It risks circumscribing the options the Review is willing to consider before assessing whether they are worth looking at. If this Review is done well, some of what follows will, for example, involve substantial changes to the AER’s revenue determination process.

Question 2: Are changes required to the revenue determination process?

1. Do you think there are problems with the amount of time and resources the current revenue determination process takes? Are there any other ways to improve the efficiency and effectiveness of the revenue determination process we should consider?
2. Do you think any changes should be made to streamline or otherwise improve the efficiency of:
 - a. the F&A stage for TNSPs and/or DNSPs?
 - b. the NSP development of regulatory proposal stage?
 - c. the revenue determination stage?If so, please explain what those changes are and the expected benefits.
3. Do you think more fundamental changes are required to the revenue determination process? If so, please explain what those changes are and the expected benefits.
4. Do you think changes should be made to the regulatory determination timetable? If so, please explain what those changes are and the expected benefits.

2.1 Issues with the current amount of time and resources

It is hard to see how the lengthy and costly revenue process currently benefits consumers. In terms of length, distribution networks must effectively start preparing revenue proposals as soon as a final determination is granted by the AER. Effectively DNSPs can be forecasting and

planning a decade ahead in the midst of a once in a century energy transition, unable to anticipate the changes in technology, policy and regulation that will occur during this time of fast evolution. Then there is the determination process itself. SA Power Networks' 2025-30 revenue proposal took over three years end to end, and its supporting "Attachment 20" documentation ran to 130 separate items, down to an Adelaide flying-fox population trend report ([IEEFA, 2024, p.38](#)). IEEFA's assessment is that the current volume of documentation "would appear to address the information asymmetry between the proponent and the regulator, but threaten to swamp the regulator in detail" ([IEEFA, 2024, p.38](#)).

The structural feature of propose–respond is that the process opens with the network's own number, and that number anchors everything after it. The AER's task becomes trimming a figure the network selected rather than independently establishing what efficient revenue looks like. Consumer advocates contest a document produced by a party with vastly greater resources and exclusive access to the underlying data. More disclosure does not fix the information asymmetry. Thirteen years of escalating disclosure is how we have thousands of pages of material in each propose-respond cycle.

In terms of cost, the AEMC consultation paper suggests networks spent approximately \$190 million preparing their most recent revenue determinations, including about \$35 million on consumer engagement (AEMC consultation paper, chapter 2). The Productivity Commission in 2013 found Victorian DNSP determination documents grew from about 450 pages in 2000 to 1,800 pages in 2010, and a full determination cycle cost around \$330 million in administrative expense, excluding merits review — so the current figure would be expected to be even higher than that suggested by the AEMC ([IEEFA, p.37](#); [McConnell and Kuiper, p.42](#)).

2.2 Assess all networks at once, every two years = more fundamental change

The most valuable structural change available to this Review is to cease requiring thirteen separate distribution determinations on staggered five-year cycles and instead assess all distribution networks simultaneously, say every one to two years.

Great Britain assesses every distribution network operator together: one price control, one timetable, one published methodology, and is currently being designed for the period after 2028 ([Ofgem, ED3 Framework Decision](#)). Britain's cycle is five years, not two, so it demonstrates simultaneity rather than frequency but to date, the British take-up of CER/DER has been much slower than Australia's.

Norway provides a model of shorter frequency. It sets revenue annually through a more mechanical process: a formula published in advance, cost data submitted on a common schedule, benchmarking results published in full, and an adjustment two cycles later to correct the difference between forecast and actual capital costs, applied with interest according to each network's share of the sector's regulated asset base (RAB) ([Norwegian Energy Regulatory Authority](#)). Both countries use ex ante incentive regulation. Both demonstrate that the volume of process the NEM currently devotes to each determination is a choice.

Simultaneous two-yearly assessment would achieve at least five positive outcomes:

1. It makes genuine comparative benchmarking more feasible. Data envelopment analysis of the kind Norway runs requires cost and asset data for the whole set of networks on a common schedule and a common definition. Staggered determinations guarantee

that the comparator data is always partly out-of-date, which is one of the objections networks raise to being benchmarked against each other.

2. It shortens the forecast horizon to something forecastable. Five years is too long for the current rate of change in distribution systems. The battery volumes of the past twelve months were not credibly forecast at the start of the present revenue determination periods, as one obvious example.
3. It ends the resourcing asymmetry enhanced by staggering. Staggering determinations by state may suit the AER's workload management, but it means consumer advocates face an unbroken sequence of revenue determination processes with no interval between them. That systematically favours the party with permanent staff assigned to the task. One process every two years, covering all networks, is contestable by even a relatively small consumer organisation. The current length of the processes requires large resources from consumer organisations in order to be able to engage effectively.
4. It removes much of the propose–respond drafting cycle, and should, if well designed, reduce the minimum \$330 million cost burden per cycle on electricity bill payers. Noting that the DNSP, AER and consumer advocate workload and transition costs of this recommendation will need to be examined through the ENRR process.
5. It makes the incentive instruments outlined in the rest of this submission workable. A menu of expenditure and sharing-factor pairs (see Question 3) has to be published to all networks at once to function. An administratively set capitalisation share (see Question 5) needs periodic recalibration on a common basis. A published utilisation and asset base benchmark (see Question 7) is very difficult to administer unless every network is measured on the same date.

Under this proposal, an exception route would be needed, and we suggest an application for closer examination, rather than a general right to reopen. A DNSP facing a genuinely large one-off transformation programme should be able to apply for a longer determination subject to more intensive audit, so that adversarial scrutiny is concentrated where the money and the uncertainty are. New Zealand operates a process of this kind, where a DNSP may apply for a customised price-quality path in place of the default path, and Wellington Electricity, Powerco and Orion have each done so ([Commerce Commission, customised price-quality path](#)). Solar Citizens offers that as a precedent for the structure and not as a tested recommendation — we have not assessed how those applications have performed for New Zealand consumers, and the Commission should examine that before borrowing this detail.

We do not support a watered down version of this proposal. A modestly shortened five-year period, or further staggering with better coordination, would consume the Review's implementation capacity while leaving the underlying problems in place.

2.3 Improving the individual stages

F&A stage. Much of what is settled at this stage is decided separately for each of thirteen distribution and five transmission networks, but with broadly similar answers. Under simultaneous assessment streamlining largely resolves itself.

Proposal stage. Networks should be required to submit, with every augmentation project above a materiality threshold, a priced flexibility (non-network) counterfactual: what it would

cost to meet the same need using flexible demand, storage or orchestrated consumer resources, and why that option was not chosen. This is the procedural expression of the procurement duty we set out at Question 6, and it is what makes the duty enforceable. Without it, the choice not to pursue a non-network option is made inside the business and is visible to nobody outside it.

The flexibility-first obligation should be proportionate and enforceable. Below the materiality threshold, a published screening test may be sufficient. Above that threshold, or wherever screening identifies a credible non-network option, the distribution network should undertake transparent market testing developed with prospective providers and consumer representatives. Failure to satisfy the obligation should affect expenditure approval and any subsequent prudency assessment. Solar Citizens recognises that flexibility procurement will take several years to scale, but this strengthens rather than weakens the case for establishing the obligation and associated procurement arrangements now.

Determination stage. The AER should publish the reset calculation in full — input data, benchmarking results, and the resulting revenue figure — and the unit costs feeding it should be anchored independently rather than accepted at each network's own reported figure. Telecommunications regulation provides an established precedent for anchoring. Ofcom's wholesale local-loop and line-rental charge controls are built on a bottom-up long-run incremental cost model of a hypothetical efficient operator building the network today, so BT's allowed charges are set against what an efficient entrant would spend rather than against BT's embedded costs ([Ofcom, LLU and WLR Charge Controls 2014-17](#)). A bottom-up model of efficient costs tests what an efficient distribution business should pay for the assets and work it needs—for example, the reasonable cost of buying and installing a distribution transformer.

2.4 The regulator must be tested too

Concentrating more of the determination in the AER's published calculation and less in the network's proposal increases the consequence of the AER getting it wrong. We think that trade is worth making. However, it does mean the AEMC's Review needs to address the accountability of the AER, which Package 2 currently does not.

The Australian National Audit Office found in 2020 that the AER "has been a partially effective regulator", and IEEFA observes that the AER's performance in economic regulation "has never been independently examined" ([IEEFA, pp.30-31](#)). Solar Citizens recommends three mechanisms to keep the AER accountable. Some measures could be adopted administratively; binding duties and an independent review mandate may require legislative or Rules changes.

First, the AER's revenue-setting and rate of return decisions should be subject to a program logic evaluation under the Commonwealth Evaluation Policy, which the AER is already within scope of through the *Public Governance, Performance and Accountability Act 2013*. The point of an evaluation of this kind is that a claim of neutrality between suppliers and consumers gets tested against outturn data instead of asserted ([Watkinson and Orme, EMAS response to the AER 2026 RoRI draft decision, pp.3-5, 8](#)). The Review should not confine itself to whether the instrument can respond to changing risk while excluding whether its parameters and inflation treatment are producing an efficient allowed return. The AER should publish each network's actual and allowed profit in dollars annually, explain material differences and feed the evidence into the next instrument.

Second, the AER should be required to respond formally and substantively to Consumer Reference Group and stakeholder submissions. Watkinson and Orme found that in the 2026 rate of return draft decision the AER "set aside, or not responded to" substantive points put to it ([EMAS response, p.xiii](#)). A submission that can be passed over without a stated reason is not good governance.

Third, the AER's economic regulation performance should be subject to genuinely independent periodic review. DNSPs are benchmarked. An independent review of AER economic regulation would test whether its decisions produce the intended consumer outcomes.

Question 3: Are changes required to improve the quality of expenditure forecasts?

1. Do you consider there are any problems with the current approach to capex and/or opex forecasting and the associated incentives that we should consider? If so, please explain what those problems are.
2. Do you consider changes are needed to the revenue determination process, the incentive framework, or both, to support better quality capex and opex forecasts and more complete information from NSPs? If so, please explain what those changes are.
3. Are there any methods used in other regulatory regimes to incentivise better quality expenditure forecasts that you think we should consider as part of the Review?

3.1 The direction of forecasting and incentives

Solar Citizens is concerned that forecast errors are more likely to be on the side of high than low demand suggesting structural challenges. The Commission's paper notes that network utilisation has declined since the mid-2000s "largely due to increases in zone sub-station capacity during this period", driven partly by jurisdictional reliability standards and by forecast demand growth in New South Wales and Queensland which "led to systematic investment in zone substation transformer capacity from 2009 to 2014" (AEMC consultation paper, section 3.5.2). Similarly, IEEFA calculates distribution regulated asset base (RAB) per customer rose 34 per cent in real terms between 2006 and 2022, and 60 per cent to its 2015 peak, while network utilisation fell from 57 per cent to 41 per cent ([IEEFA, p.5](#)). Consumers are still paying a return on the capacity and will be for decades. Meanwhile, the trajectory seems to be continuing with SA Power Networks, Ergon and Energex each proposed capex increases of 20 to 22 per cent for 2025-30 against 2020-25, in regions where rooftop solar penetration exceeds 45 per cent ([IEEFA, p.6](#)).

A network that over-forecasts demand receives an allowance, builds the asset and earns a return on it for its operating life. A network that under-forecasts risks breaching a reliability standard, with regulatory penalty and public criticism attached to identifiable people inside the business. Under genuine uncertainty, forecasting high is the correct commercial answer. The AER says so itself: "Network service providers receive a guaranteed return on their RAB. For this reason, they have an incentive to overinvest if their allowed rate of return exceeds their actual financing costs" ([AER, *State of the Energy Market 2023*, quoted in IEEFA, p.59](#)).

3.2 Menu regulation should be considered

The regulatory economics literature suggests an instrument that reduces information asymmetry without asking the AER to out-forecast the network, and Solar Citizens recommends

the Commission examine how menu regulation might be applied in the NEM. Under menu regulation the regulator publishes, ahead of each reset, a schedule of expenditure levels (how much a network is allowed to spend and recover) and linked sharing rates (how much of any under-spend a network gets to keep versus hand back to customers) constructed so that as the claimed expenditure needed rises, the sharing rate falls. If a network chooses to pick a modest budget, it keeps a generous slice of any savings. If it picks a lavish budget, it keeps much less. Each network then picks its own point on the published schedule ([Oxera, Menu regulation: is it here to stay?](#)). A network that inflates its forecast wins a larger allowance but buys it at a worse sharing rate and a lower score on the efficiency of the costs it has claimed. Ofgem states the purpose of its Business Plan Incentive in these terms — to overcome the information asymmetry between the regulator and the companies it regulates. Ofgem used it from its fourth distribution price control review onwards, and Italy applies the same logic in Basic ROSS, the first stage of Italy's new method for regulating electricity and gas networks ([Regulatory Assistance Project, Italy case study](#)).

Ofgem's Business Plan Incentive pays or charges each network according to how efficient and well-justified its own expenditure proposal is, measured in basis points of return on regulatory equity. In the RIIO-3 determinations for the 2026–31 period, the assessment was capped at ± 60 basis points: up to +40 and –20 basis points for the efficiency and justification of the costs proposed, and up to ± 20 basis points for the clarity and credibility of the plan itself. For example, Scottish Power Transmission earned +11.8 basis points, worth about £12.5 million over five years, while Southern Gas Networks lost 11.6 basis points, worth about –£16.8 million ([Ofgem, RIIO-3 Final Determinations Overview Document, December 2025](#)). For electricity distribution, Ofgem's May 2026 decision for the 2028–33 period calculates the reward as the gap between a benchmark company's costs and the DNSP's own proposed costs, multiplied by the sharing factor under the totex incentive mechanism, capped at +40 basis points. ([Ofgem, ED3 Sector Specific Methodology Decision, core document, May 2026](#))

The regulator never has to know whether a given network is truly high-cost or low-cost. It just publishes the menu and lets the firms sort themselves. The structure of the menu makes honesty the most profitable strategy for every type of firm — high-cost or low-cost — without the regulator needing to out-forecast anyone. A well-designed menu makes truth-telling the rational choice, and the information asymmetry becomes unprofitable to exploit rather than something that needs to be eliminated ([Joskow, Incentive Regulation in Theory and Practice, NBER Working Paper 14530](#)). Under simultaneous two-yearly assessment, each network's forecasts from the preceding cycles and their outturn should be published alongside the reset calculation as a matter of course.

3.3 How to manage uncertain augmentation

Lumpy discrete augmentation does not fit a menu well and needs separate treatment. Ofgem's framework recognises this through its uncertainty mechanisms, which sit alongside the baseline totex allowances and the menu-style incentives described above. Ofgem sets baseline allowances only where it is satisfied of the need and the cost certainty of the proposed work; where uncertainty remains, expenditure is moved out of the baseline and into a pipeline of uncertainty mechanisms that release funding only when the need is demonstrated. For electricity distribution under ED3, Ofgem applies a sensitivity analysis to each network's load plan, splitting expenditure into high-confidence, low-regret investment that enters the baseline,

and lower-confidence investment that sits in uncertainty mechanisms and is triggered if demand materialises. The mechanism types include re-openers — defined windows through which networks submit project-specific applications that Ofgem assesses and determines — volume drivers for uncertain quantities at known unit costs, and use-it-or-lose-it allowances that return unspent funding to consumers ([CERRE, Towards a More Dynamic Regulation for Energy Networks](#); [Ofgem, ED3 rules announcement, May 2026](#)).

Cost recovery should not prevent a distribution network from entering an efficiently procured flexibility contract merely because the contract crosses a revenue determination boundary. Where a commitment beyond the current regulatory period is demonstrably necessary to secure the least-cost non-network option — that is, for longer than two years under the determination cycle proposed by Solar Citizens — the AER should be able to approve its cost-recovery treatment in advance. Any approval should preserve competition, avoid unnecessary lock-in and leave the DNSP responsible for procurement, performance and delivery risks it can manage. This is consistent with experience in Britain, where distribution networks have offered flexibility contracts with terms of up to seven years.

One design refinement worth investigation is how Britain's Office of Rail and Road separates enhancements from recurrent renewals but goes further. Enhancements are funded through a client-led pipeline with their own governance and value-for-money tests, and enter the RAB only once delivered against an agreed baseline. Renewals funding is ring-fenced so a delayed or cancelled enhancement cannot be used to justify deferring routine asset renewal ([ORR, Enhancements in CP7: roles and responsibilities](#)). The Commission should consider whether an explicit ring-fence between augmentation and recurrent expenditure would strengthen the design.

Question 4: Are changes required in how consumer preferences are reflected in the revenue determination process?

4.1 Issues with the current approach

Consumer engagement in revenue determinations is a fraught issue because of the complexity of distribution network forecasting, planning and operations and the information asymmetry inherent in any engagement process. It's hard to find examples of where a consumer or consumer organisation has changed any substantial aspect of any DNSP's revenue proposal, despite the tens of millions of dollars. At worst, consumer engagement is performative or persuasive, securing social licence for pre-existing plans.

Timing is the first problem. Engagement generally happens after the network has formed its investment plan. Consumers are asked about trade-offs inside a settled capital programme — reliability against price, this project before that one — rather than about whether the programme is needed at the proposed scale. The decisions that matter are taken before consumers are in the room.

Resourcing is the second. According to the AEMC consultation paper, networks deployed \$35 million on engagement alone in the last round of revenue resets. Consumer advocacy organisations' revenue are a fraction of that, without access to the network's underlying asset and demand data, across multiple simultaneous determinations. Calling the result 'engagement' between parties overstates the symmetry considerably. This is one of the

practical reasons Solar Citizens supports assessing all networks at once, every two years: it is the difference between a process a small organisation can contest properly and one it can only usually observe.

Third, and specific to the consumers we represent, owners of solar and batteries are a distinct population whose interests general residential representation does not capture. Over four and a half million households and businesses now have a direct financial stake in whether their network builds poles and wires or uses what consumers have already installed. We suggest that interest needs explicit consideration.

4.2 How preferences should be identified and reflected

There is a need for clarity on the issue of consumer preferences and where they should be applied in the revenue determination process. Where consumers express a clear view on matters within their competence — service standards, the balance of price against reliability, tariff structures, willingness to make their equipment available to the network — the AER should be required to state in its determination how that view affected the outcome. At present a network can document consumer extensive engagement and a determination can issue with no visible trace of it.

Solar Citizens does not support retailers taking a more prominent role in representing consumer preferences in revenue determinations. Retailers are commercial parties with their own interests in network tariff structures, in the treatment of exports, and in the terms on which consumer resources participate. Those interests overlap with consumers' interests in places and diverge sharply in others. A retailer's position on fixed charges, on export pricing, or on who controls a household battery is a position taken on its own behalf. Retailers are entitled to advocate for themselves. They are not consumer representatives, and routing consumer preferences through them would displace bodies that represent consumers. Retailers already participate fully in these processes in their own right.

4.3 The obligation sits with the AER

The current process does not consistently show how a preference expressed during engagement changed the expenditure approved; the Commission should test this across a sample of determinations. Solar Citizens suggests the Commission consider changes to what's required of the AER in every determination. Such requirements could include, to:

- state how consumer preferences on price and service standards were weighed against the proposed expenditure, and where the AER departed from a clearly expressed consumer preference, explain why the alternative it approved produces a better outcome for consumers;
- test whether the expenditure consumers were asked about is the same expenditure the AER is approving — and if the scope has changed between engagement and determination, require the network to return to consumers on the change before the determination is finalised;
- publish its assessment of whether the engagement process was adequate to support the claims the network makes in its proposal, separately from the network's own account of that engagement.

However, engagement is not an alternative to reform of the financial incentives. Without totex, without a flexibility-first obligation, without a menu that rewards honest forecasting, engagement will continue to produce well-documented agreement with decisions that were taken before anyone was in the room.

Question 5: Are changes required to levelise incentives between capex and opex?

1. Does the current framework provide a level playing field for all technology types at both the transmission and distribution level?
2. Do you think that the current framework incentivises NSPs to favour capex- over opex-based solutions? If so, what are the most important factors that drive this outcome?
3. Do you have any observations on how interactions between the CESS and EBSS may impact efficient NSP choices in relation to capex and non-network solutions?
4. Do you have observations on the effectiveness of the DMIS in driving non-network solutions?
5. Do you have any views on improvements or alternatives to incentivise NNOs?

This is the question that matters most for the consumers Solar Citizens represents.

5.1 Is there a level playing field for all technology types?

No, for the reasons detailed below.

5.2 Does the current approach favour capex, and what drives it?

Yes. Under the current approach, the dominant driver is that the return on capital accrues only to capitalised expenditure.

In simple terms, a dollar spent on a transformer enters the regulated asset base (RAB) and earns a regulated return plus depreciation for the life of the asset. A dollar spent procuring flexible demand that relieves the same constraint is recovered once, in the year it is incurred, and earns nothing further. Even where the flexibility option is cheaper in total, the network option is worth more to the business. No incentive scheme currently in the Rules is substantial enough to close a gap of that type, because the gap is not a few percentage points on a project. There are substantially different timing and earnings opportunities created when capitalised spending enters the RAB and an equivalent service is recovered as operating expenditure.

Networks also set their own capitalisation policy. The boundary between capital and operating expenditure is determined in significant part by the regulated business, subject to review. Giving a business with a structural preference for one side of the boundary substantial control over where the boundary sits is an obvious conflict of interest.

Solar Citizens does not suggest that these outcomes reflect bad faith on the part of network businesses. Rather, they reflect the incentives and requirements created by the current Rules. Our focus is therefore on improving those arrangements so they better support the outcomes consumers and the energy system need.

In more technical terms, capital expenditure (capex) below the regulatory allowance is recovered with certainty and earns a return through the weighted average cost of capital (WACC) applied to the regulatory asset base (RAB) for decades, while operating expenditure (opex) is reassessed by the AER every five years and demand-side solutions typically attract

only contracted payments with no comparable guaranteed return (NEM Reform, p.34). This is the Averch-Johnson effect. Ross Garnaut's 2011 Review found the regime "provides excessive incentives for investment whether or not it is wanted by consumers", a feature IEEFA found "still in place 13 years later" (IEEFA, p.26). KPMG's 2018 analysis found a 1% gap between a network's actual financing cost and its allowed WACC can generate up to AU\$150 million a year in profit (IEEFA, p.26; McConnell and Kuiper, p.34).

5.3 Interactions between the CESS and EBSS

The CESS rewards a network for spending less than its capex allowance. The EBSS does the same for opex. The two schemes do not work the same way: the share of savings the network keeps differs, and the period over which those savings are retained before flowing through to consumers differs as well. Running these as two separate schemes creates an incentive to choose the incentive scheme with more favourable terms. However, there is a real risk the Review takes the wrong turning here. Aligning the sharing rates between the CESS and the EBSS is not a solution to the capex bias. It is a tidy-up that leaves the return on capital untouched, and it would be very easy to present as having addressed Question 5. The bias does not arise from a mismatch between two sharing rates. It arises from the fact that only one category of expenditure earns a return for decades. Solar Citizens does not support the Review treating changes to the CESS and EBSS as the answer to the question of different earnings from capex and opex.

5.4 The DMIS is the wrong instrument, and the evidence is now conclusive

The Commission's own figures answer the first question: of roughly \$1 billion notionally available across the 2017-2022 revenue period, only \$3.2 million was actually spent on demand management through the DMIS (IEEFA, p.33; McConnell and Kuiper, pp.34-35).

The design of the DMIS explains this outcome. The scheme pays up to 50 per cent of project cost, capped at the estimated net benefit, with total accruals capped at 1 per cent of allowed revenue for the year. Consider a network choosing between a \$10 million augmentation and a \$6 million non-network alternative. The augmentation enters the asset base and earns a return and depreciation over its life. The alternative is recovered as incurred and may attract a payment constrained by the 50 per cent limit, the net benefit cap, and a 1 per cent annual envelope.

The Commission's paper records that the DMIS was introduced in its current form in 2015 to address a perceived structural bias toward network solutions, and that the concerns then included that benefits from non-network options are "short term relative to the regulated rate of return earned on (capex-based) network investment", and that DNSPs "do not capture the benefits achieved at other levels of the supply chain (such as reduced generation costs)" (section 3.2.4). Those diagnoses were correct. The instrument was too small to act on them and we now have eleven years of evidence to prove it. Solar Citizens solution is for the regulator to set a fast/slow money split discussed in section 5.5 and to pay networks an avoided network cost payment, set out in section 5.6.

5.5 Set the capitalisation share administratively

The Commission's paper sets out a potential total expenditure approach involving "applying a predetermined split to totex, with one proportion recovered as fast money and the remainder

added to the regulatory asset value". Solar Citizens supports the capitalisation share being set administratively. Italy's ARERA has implemented exactly this under ROSS, with the capitalisation share set administratively as an average of each DNSP's historical and forward-looking opex/capex mix rather than following the DNSP's own accounting choice ([Regulatory Assistance Project, Italy case study](#)). The Commission's own paper states the result: "the network is incentivised to find the most efficient (least cost) way to meet its obligations, rather than by shifting expenditure into the category receiving more preferable regulatory treatment".

Predetermined capitalisation addresses one source of the preference for network assets, but it does not address every source. It changes the treatment of expenditure so that the proportion added to the RAB does not depend on whether the DNSP builds an asset or buys a service. If the same capitalisation rate applies to both options, the DNSP cannot increase the amount entering the RAB merely by choosing the asset. This makes the comparison between a transformer and a flexibility service more neutral.

A separate issue is whether the rate of return applied to the capitalised share is set correctly. If the allowed return is higher than the DNSP's efficient cost of finance, capitalised expenditure remains profitable. Predetermined capitalisation limits this effect by applying the same capitalisation share to asset and service expenditure, but it does not eliminate it. Consumers would still pay the excess return on whatever proportion of total expenditure enters the RAB.

These reforms address different problems. Predetermined capitalisation reduces the advantage a DNSP can obtain by choosing or classifying expenditure as capex. A properly calibrated Rate of Return Instrument limits the risk that consumers pay more than the efficient cost of financing expenditure added to the RAB. Solar Citizens considers both necessary.

A fixed capitalisation share does not replace an incentive to control total expenditure. The two measures need to be designed together so that a DNSP has reason to choose an efficient solution and deliver the services consumers are paying for. Ofgem's ED3 decision retains its Totex Incentive Mechanism while strengthening the link between investment funding and delivery, including provision for funding to be returned where planned outputs are not delivered ([Ofgem, ED3 Framework Decision](#)).

5.6 Pay the avoided network cost

Solar Citizens suggests the Commission consider an Avoided Network Cost Payment to replace the DMIS, using the non-wires alternative incentive operated by Orange and Rockland in New York as a design comparison. The utility's initial incentive is 30 per cent of the estimated net benefit of the non-network option relative to conventional investment. Its final incentive is adjusted for 50 per cent of any difference between estimated and actual non-network costs, subject to a zero floor and a ceiling of 50 per cent of the initial net benefit. The unamortised incentive balance earns the utility's approved weighted average cost of capital ([NY PSC, Orange and Rockland non-wires alternative operating procedure](#)).

This measure is secondary to the capitalisation share at section 5.5 and should not be adopted in place of it. The payment also does something the capitalisation share cannot. As set out at section 6.2, a non-network solution frequently produces benefits beyond the DNSP's own avoided expenditure — reduced wholesale and generation cost, avoided transmission investment, avoided expenditure by consumers, and emissions reductions. The Commission has itself recorded this as the original reason for the DMIS, noting that DNSPs "do not capture

the benefits achieved at other levels of the supply chain (such as reduced generation costs)" (section 3.2.4). An Australian payment could recognise some of those wider benefits, but the Commission would need to specify which benefits enter the calculation and how they are valued. The Orange and Rockland precedent does not, by itself, establish a payment for avoided wholesale or transmission costs or emissions reductions.

Two design points follow. The payment should sit outside total expenditure, as the CESS and EBSS do, so that it is not itself subject to the capitalisation split. And the share should be set on the understanding that the capitalisation share has already removed the bias — a payment calibrated as though it had to overcome the full capex advantage, as the Orange and Rockland design must in a conventional rate-base regime, would overshoot in a regime where that advantage has already been removed. Solar Citizens does not propose a figure and suggests the Commission determine one through public consultation once the capitalisation share is settled.

5.7 Reward decarbonisation, using the price that already exists

Solar Citizens recommends the AEMC consider creating a Decarbonisation Incentive Scheme, valuing a DNSP's measured contribution to electrification — supporting customers off reticulated and bottled gas, and facilitating electric vehicle charging — at the AER's published interim value of emissions reduction - which is \$80/tCO₂-e for 2026 (AUD 2023). The value rises annually under the ministers' agreed method and the AER publishes the schedule, so a scheme should reference the applicable year's value rather than a fixed figure. DNSPs could be allocated a defined proportion of the estimated reductions, say under an AER guideline.

We note electrification raises network utilisation, so there is a risk that a decarbonisation reward and a utilisation reward (see question 7) can pay twice for the same outcome. One option would be for the scheme to be calibrated to reward efficient and orchestrated electrification specifically such that new load lands in existing headroom rather than triggering augmentation, for example.

Question 6: How should we approach DSO incentives through this Review?

1. What are your views on how the need for new DSO incentives should be considered?
2. How broadly should the concept of the 'whole system' be defined for DSOs? Please provide examples of the benefits that would fall within your preferred scope and explain why it would be appropriate for a DSO to be incentivised to maximise those benefits.
3. What level of quality and depth of coordination should DSOs be responsible for delivering?
4. Should these outcomes be achieved through obligations, incentives or a combination of both?
5. Where incentives may be appropriate, which aspects of coordination should they target?

6.1 National consistency in 'DSO' functions

The fundamental technical change in distribution networks is the transition from predominantly static, one-way operation to dynamic management of two-way imports and exports. DNSPs will need greater visibility, operational systems, forecasting, transparent export management and the ability to procure distribution flexibility. The National Electricity Rules should reflect these changes. However, this does not establish a need to create a separate Distribution System Operator (DSO) role with broad functions that overlap with, or extend beyond, the role of a

dynamically operating DNSP. Nor does it necessitate the need for new incentive arrangements to support DSO activities.

Solar Citizens view is that in general, a DNSP should dynamically manage network imports and exports within transparent operational limits; publish standardised, timely information about available capacity, constraints and network needs; and procure distribution flexibility first where it is the efficient means of meeting an identified distribution-network need.

The Rules should require national consistency in the 'DSO' functions where it matters for consumers, aggregators, retailers and technology providers, including:

- voltage management
- dynamic operating-envelope methodologies and interfaces (see [IEEFA, 2024](#))
- publication of network constraints, available capacity and curtailment information;
- data standards and access arrangements;
- operating interfaces for aggregators and CER service providers;
- definitions and procurement processes for distribution flexibility; and
- any future dynamic network-pricing arrangements.

Poor voltage performance directly reduces the value consumers get from equipment they own by reducing appliance lifetime and curtailing exports. The Victorian Essential Services Commission already requires reporting of the number and proportion of assets above the maximum and below the minimum voltage limit; more sophisticated measures accounting for the duration of over-voltages should be developed by the AEMC for the entire NEM and compliance against the nominal voltage standard required. ([McConnell and Kuiper, pp.44-46](#)).

Formalising DSO functions will increase DNSPs' control over information and access conditions that determine whether consumers can connect, export, enrol with an aggregator or provide flexibility. National DSO arrangements must therefore include enforceable requirements for equivalent and timely access to network information, non-discrimination between affiliated and independent service providers, transparent ring-fencing waiver decisions, and published compliance and enforcement outcomes.

Solar Citizens does not support a separate DSO incentive at this stage. The specified functions should first be established as enforceable obligations. Creating DSO incentives would not seem to be an efficient way to support functions that should be core to the functioning of a DNSP with high penetration of CER/DER.

6.2 How broadly the 'whole system' should be defined

Solar Citizens disagrees with the premise that DSOs should be responsible for achieving efficient whole-of-system outcomes. A DNSP cannot determine or optimise wholesale market participation, retailer contracting, aggregation arrangements, consumer preferences or the competing value streams available to each consumer-owned device. An objective requiring a regulated monopoly to facilitate the use of all available consumer energy resources in the most economically efficient manner for whole-of-system benefit is not achievable, and the attempt would extend a monopoly's reach into decisions that belong to consumers and their chosen agents. A broad coordination mandate would be difficult to measure and might give a monopoly influence over decisions better left to consumers and their chosen providers

The network-facing role should be defined narrowly and precisely, for example:

A DNSP should dynamically manage imports and exports within transparent operational limits; publish standardised, timely information about available capacity, constraints, curtailment and network needs; and competitively procure distribution flexibility where that is the efficient way to meet an identified distribution network need.

How a consumer, retailer or aggregator uses a customer-owned device beyond those network constraints is a separate matter. Consumers should be able to choose whether to participate in energy and flexibility markets, who acts on their behalf, and which services their resources provide. The suggestion that DSOs should ‘coordinate’ CER strikes us as strange given the NEM was set up on the basis of efficient competition and voluntary participation in markets.

Solar Citizens also does not support making the DNSP responsible for facilitating value stacking. Market-wide value stacking and dispatch interaction are properly matters for AEMO and the market rules. The DNSP's responsibility should be that distribution constraints and service requirements are visible, predictable and applied only where genuinely needed, so that they do not unnecessarily prevent a consumer resource from providing other services.

The only exception is where examining whole of system value is appropriate for flexibility. When a DNSP or the AER assesses whether a non-network option beats building, the benefits counted should include those falling outside the DNSP's own expenditure — avoided wholesale energy and generation cost, avoided transmission investment, avoided expenditure by consumers themselves, and emissions reductions valued at the ministers' stated value. For example, shifting household battery discharge into high wholesale price periods reduces generation cost for every consumer, not network cost in one DNSP's area. And coordinated management of EV charging and storage reduces the transmission and generation capacity the whole system needs.

6.3 One national interface for distribution flexibility, not thirteen

Solar Citizens recommends national consistency in how DNSPs advertise and procure local flexibility. A provider operating across network areas should face common service definitions, qualification requirements, data formats and a common market interface, rather than thirteen bespoke processes. The Commission should assess whether a single national platform or interoperable platforms can deliver those requirements at lower total cost.

Italy provides a useful example of reuse. Areti procures flexibility for Rome through RomeFlex, hosted on the local flexibility market platform operated by GME, Italy's energy-market operator ([ARERA, DSO Flex presentation](#)). The EU DSO Entity reports that the RomeFlex environment can be reused by other DNSPs, allowing them to begin procuring flexibility in around six months. It reports that Areti currently manages 22 MW of flexibility from 1,300 customers through 18 service providers ([ARERA, I DSO facilitatori neutrali e acquirenti di servizi ancillari locali](#); [ARERA, Deliberazione 352/2021/R/eel](#)).

Reuse is not the same as a requirement to use one platform. The Italian example shows why shared systems and rules can reduce the work required to establish a local market, but it does not establish that a single operator would be the least-cost choice for the NEM. Solar Citizens recommends that the Commission require common national access and procurement rules, then compare the full costs and benefits of one national platform with interoperable platforms before deciding who should operate them. DNSPs would remain responsible for identifying local needs and procuring services to meet them.

Question 7: Incentives to support efficient network utilisation

1. Do you consider that there should be more explicit incentives established to drive efficient network utilisation by NSPs?
2. How could such a mechanism be designed and how could measurement limitations be addressed?
3. Are there other options to drive efficient utilisation that you would like the AEMC to consider?

7.1 Should there be more explicit incentives for efficient utilisation?

Yes, with careful design. Solar Citizens appreciates that DNSPs may be concerned about incentives based on utilisation which may be impacted by factors beyond the DNSP's control, such as the current boom in data centres. However, measuring two way utilisation on a distribution network is an important way of evaluating a DNSP's performance in the efficient and effective use of its assets and distribution flexibility. Creating appropriate incentives will not be straightforward but it could help significantly change the forecasting, planning and operation of distribution networks in consumers' interests.

Of course, an incentive on measured utilisation, standing alone, is satisfied by growing demand just as readily as by avoiding capacity. It should therefore be introduced only alongside the procurement obligation at Question 6 and the priced comparison at Question 2. On its own it risks rewarding load growth for its own sake.

7.2 Design and measurement

As the consultation paper makes clear, the current measure of network utilisation is annual maximum demand at each substation compared with that substation's capacity. It is peak-only, single-direction and substation-level. It does not measure reverse flows and it cannot see hosting capacity at the low-voltage level where consumer equipment actually connects.

Australian work has already been done on what could replace the current metric, and Solar Citizens recommends the Commission start from this work, rather than from first principles. Researchers at the Institute for Sustainable Futures at the University of Technology Sydney, with support from Energy Consumers Australia, have proposed two headline measures ([Langham, Ibrahim, Rispler and Roche, *Reimagining Network Utilisation in the Era of Consumer Energy Resources*, 2024, discussed in McConnell and Kuiper, pp.42-44](#)):

- Total Energy Throughput Utilisation, which measures the portion of network capacity used by energy flows in either direction and accounts for locally consumed consumer resource energy, so that it recognises customer value delivered through imports, exports and self-consumption rather than only peak import.
- Two-way Power Flow Utilisation, which measures the capacity risk accrued in delivering that throughput and exposes the time-of-day and seasonal variation in two-way use that determines how throughput can be increased.

These are complemented by asset-level measures for voltage compliance, reliability and accumulated asset risk, and by a simple inflation-adjusted network cost per unit and per customer. Testing against real network data found that Total Energy Throughput Utilisation responded as intended to increased solar with battery load shifting and to other consumer actions that reduce curtailment.

The UTS authors are explicit that these measures were designed as performance metrics and not as the basis for regulatory incentives, but they are also clear that the Total Energy

Throughput Utilisation scheme could be used to reward performance on exports and self-consumption rather than only on peak import. It could also absorb much of what is proposed as a separate DSO incentive and Solar Citizens recommends the AEMC test its potential as an incentive metric. We would also suggest investigating how this metric could be calculated at efficient cost is a substantive implementation question worth the AEMC's time.

7.3 Publish the benchmarks annually, across every network at once

Solar Citizens recommends the AER be required to publish annual, formula-driven benchmarking of both the RAB and utilisation, across all distribution networks simultaneously, adjusting the results to account for differences in the conditions they operate under (customer density, terrain, vegetation, climate, the proportion of underground cable, etc) — the method Norway uses ([Norwegian Energy Regulatory Authority](#)).

We note that Norway benchmarks a much larger set of DNSPs than the NEM's thirteen, and a small comparator set weakens any frontier method. That could be a reason to supplement domestic benchmarking with a disciplined international comparator method and to publish the comparator choice for the contest. It is also a direct argument for assessing all networks simultaneously, as we recommend at Question 2.

7.4 The importance of the specifics of network data provision

This data provision could fit well with the Commission's recent rule on enhancing distribution network planning and reporting which requires the AER to prepare guidelines prescribing the network data that DNSPs must publish, having regard to visibility of the state of the network, net economic benefit, protection of confidential and private information, and existing reporting obligations ([AEMC, *Enhancing distribution network planning and reporting*](#)).

Solar Citizens suggests that the Commission use this Review to detail what those AER guidelines need to contain, to ensure utilisation can become visible. This could include:

- hosting capacity and available import and export headroom at feeder level;
- curtailment, by feeder and by cause;
- the measures at section 7.2 above once developed; and
- a consistent national format so that data can be compared across the thirteen DNSPs and used by a party operating in more than one network area.

In addition, distribution network development plan's five-yearly publication is tied to the regulatory proposal cycle, so if determinations move to a two-year cadence as we recommend at Question 2, the plan and its annual update should follow.

Question 8: Are changes required to better incentivise network innovation?

1. What are your views on the effectiveness of the incentive framework for network innovation?
2. What improvements can be made to this framework to drive greater levels of innovation?

8.1 Effectiveness of the current arrangements

While there is some excellent innovative work being done in DNSPs, the incentive arrangements do not meet the needs of the sector or of consumers. As the Consultation Paper

states, the AER approved \$9.87 million under the Demand Management Innovation Allowance (DMIA) Mechanism in total in FY2025. Ten million dollars across every network in the NEM, in the same year when Australian consumers installed 14 GWh of battery storage. That is not a sufficient research and development budget for an industry in the middle of the largest transformation in its history.

8.2 Improvements

We suggest funding for innovation should sit outside the expenditure incentive schemes, so that a DNSP is neither rewarded for underspending it nor penalised for a trial that does not work. Solar Citizens suggests the Commission consider recommending a dedicated network innovation fund, perhaps administered by ARENA, on the model of the competitively allocated innovation funding Ofgem has run in Great Britain since RIIO ([McConnell and Kuiper, p.48](#)). ARENA already assesses energy technology proposals, already publishes results as a condition of funding, and has no interest in the size of any DNSP's RAB. Competitive allocation across DNSPs also breaks the assumption that each of thirteen DNSPs needs its own budget to solve its own version of a shared problem. Great care would be needed to design an innovation funding scheme so it was efficient and effective. In particular, the funding approach would need to be streamlined to allow for prompt approvals and rigorous to avoid duplication.

New Zealand's arrangements are also worth considering. It sets a ring-fenced allowance at 0.8 per cent of maximum allowable revenue, aggregating to a maximum NZ\$91.9 million across fifteen DNSPs over 2025-30, recoverable at up to 100 per cent where the project is unlikely to produce a financial benefit to the DNSP within five years and at a reduced rate otherwise, with a share reserved for projects undertaken jointly ([Commerce Commission, EDB DPP4 final decision, Attachment D](#)). Solar Citizens raises this as a design worth examining rather than as a recommendation to adopt: we have not assessed how it has performed in practice, the New Zealand regime differs from the NEM in the scope of the regulator's discretion, and any percentage for the NEM would need to be set independently.

Regardless of what innovation funding model is chosen, any project consumers fund should be reported publicly in enough detail that another DNSP, an aggregator or a researcher can use the result (and preferably the data), and negative results should be published as a condition of funding.

Question 9: Does the framework appropriately allocate risk given the changes underway?

1. Do you consider that some sources of uncertainty are increasing in the context of the energy transition? Given the changes underway does the framework appropriately allocate risk between NSPs and consumers?
2. Are the various intra period and ex post adjustment mechanisms appropriately targeted and fit for purpose?

9.1 Increasing uncertainty and the allocation of risk

We agree that uncertainty is increasing and with the Commission that consumers ultimately bear the consequences of forecast error and are also likely to be bearing a greater share or risk with the greater reliance on intra period adjustment mechanisms. Solar Citizens greatly appreciates the Commission's willingness to 'assess whether the current balance between ex

ante regulation and intra period adjustment continues to promote efficient investment and efficient use of electricity services in the long term interests of consumers, or whether increasing reliance on these mechanisms is changing the incentive properties of the framework and the way in which risk is shared between consumers and NSPs’.

Where a DNSP can influence utilisation, staging, reversibility or obsolescence risk, its exposure should be specified before the investment decision. For example, a DNSP should bear greater risk where it could have staged an augmentation, delayed commitment until demand became clearer or used flexibility to preserve future options. Advance risk allocation should complement rather than displace ex post review. Advance allocation addresses the consequences of uncertainty that was recognised when the decision was made; ex post review addresses whether the decision itself was prudent, including whether the DNSP properly examined a credible non-network alternative.

9.2 Are the intra-period and ex post adjustment mechanisms fit for purpose?

The paper states that the NER empowers the AER to review capital expenditure after it is incurred and exclude imprudent or inefficient expenditure from the RAB, and that this power "applies to all capital expenditure" regardless of whether it was within or above the original allowance. We agree that this is a fundamental consumer protection. In practice, review is initiated through the process in the AER's Capital Expenditure Incentive Guidelines, triggered under three limbs: overspend against the approved allowance, related party margins or a change in capitalisation policy. As the paper states, "prudency and efficiency assessments apply only to the overspend limb" (AEMC consultation paper, chapter 4). While this mechanism detects overspending against a forecast, it does not detect over-building within a forecast. The 2009 to 2014 zone substation episode the Commission describes was the second kind of failure, not the first ([IEEFA, p.30](#)). IEEFA now estimates that regulated electricity networks received around \$15 billion in supernormal profits between 2014 and 2023, much of it earned within regulatory allowances rather than through expenditure above them ([IEEFA, 2025](#)). An ex post mechanism triggered principally by overspending cannot address that failure mode.

The Rules therefore contain a broad power that the guidelines make almost impossible to exercise against the failure mode that has actually cost consumers the most. The fact that the AER has exercised its ex post capex-exclusion power only once as far as we could tell — in Ergon Energy's 2025–30 distribution determination, where \$504.1 million of 2018–19 to 2022–23 capex was excluded from the opening RAB — gives grounds for genuine concern about the mechanism's practical effect. The Ergon decision demonstrates that the power can be used, but its apparent rarity calls for a published account of when review was considered and why it was or was not initiated. The rarity cuts two ways: it may reflect restraint and sound judgment by the AER, but it may equally signal that the threshold for intervention is set so high, or the evidentiary burden so demanding, that the mechanism functions more as a theoretical deterrent than a real accountability tool. Solar Citizens recommends the Commission assess the evidence and close the gap between the theory and the practice.

The prudency test asks whether the decision to incur expenditure was reasonable based on what the network knew or should have known at the time. The Rules or the AER's guidelines should state that, for augmentation expenditure, a network is expected to have compared the network option against a priced distribution flexibility (non-network options), and that prudency assessment includes whether that comparison was made and reasonably conducted.

In addition, ex post review should be capable of writing down the asset base. The ACCC recommended in its 2018 Retail Electricity Pricing Inquiry that Queensland, New South Wales and Tasmania take "immediate steps to remedy the past over-investment of their network businesses", through write-downs or network charge rebates, targeting at least \$100 a year for the average residential customer ([IEEFA, pp.20-21](#)), but this did not occur.

Solar Citizens would like to see the rules amended so that a review can be initiated on evidence of material and sustained under-utilisation of capacity relative to the forecast that justified it, whether or not there was an overspend, and so that exclusion from the asset base is an available outcome. We suggest the annual published benchmarking at Question 7 is what would supply the evidence to initiate such a review.

We recognise this is a consequential recommendation for network businesses and their financiers, and we are not proposing it lightly or retrospectively as a penalty. It is the necessary protection for consumers from excessive capacity.

The ACCC also recommended in 2018 that the Rules "explicitly allow for a process whereby network assets may be stranded and the costs of that stranding is shared between users and networks" ([IEEFA, p.27](#); [McConnell and Kuiper, p.41](#)). The ACCC directed that task to this Commission: it recommended that the AEMC "determine the definition of 'stranding' and how the costs of 'stranding' can be shared".

Both ex post review and stranding changes are needed. Ex post review addresses an investment the DNSP should not have made; the loss then falls on the DNSP. Stranding addresses an asset that is genuinely no longer needed because consumers changed what they do, where no one made an unreasonable decision; the loss is then shared. Without the no-fault route, every write-down has to be argued as imprudence against a plan the AER approved, which is a substantial part of why none has occurred. The ACCC noted a related gap in the primary law: the national gas law allows any capital expenditure to be assessed for redundancy, and the national electricity law contains no equivalent provision.

Stranding would allow assets such as underused single-wire-earth-return lines to be written down and replaced with stand-alone power systems, microgrids and other CER/DER alternatives without the network or its financiers carrying the entire loss — and, equally, without consumers carrying it alone. Western Power has decided to convert most of its remote line length to stand-alone power systems and microgrids on a similar basis. That decision reflects the fact that maintaining long, lightly used rural lines can impose costs far exceeding the cost of supplying the same customers through appropriately designed local systems. In such cases, continued investment in conventional poles-and-wires assets is not neutral: it locks consumers into avoidable replacement and maintenance expenditure, while potentially delaying more reliable and resilient supply options. A regulatory allowance for managed asset stranding would enable DNSPs to assess these alternatives on their whole-of-system cost, reliability, resilience and customer-service merits, rather than favouring network replacement merely because the existing regulatory arrangements protect the value of the incumbent asset base.

It's worth noting the link to Question 11 here. A network bearing a share of stranding risk has a reason to test augmentation against non-network options before building.

Question 10: Does the framework appropriately enable anticipatory investment?

1. Does the current framework appropriately balance the costs of investing too early against the costs of investing too late, and does it support investment at the point that maximises long term consumer value?
2. Are there aspects of the regulatory framework that act as a barrier to efficient anticipatory investment? Please provide evidence or case studies.

10.1 The balance between investing too early and too late - need to focus on DSO investment

The Commission notes anticipatory investment is ‘more easily done for a single, well-defined project than for a broad, trend-based program spanning many individual assets’ and this is an issue for the development of DNSPs into DSOs and therefore for Solar Citizens. The priority for early investment for DNSPs should be on the IT and data infrastructure that supports, for example, flexible exports and dynamic management of the network.

10.2 Barriers to efficient anticipatory investment, with evidence

Solar Citizens recommends that for all network infrastructure investment, including anticipatory, flexibility should come first, the test should be explicit, the alternative should be priced, and the commitment should be staged wherever staging is possible. Anticipatory investment proposals should therefore have to state the cost of waiting alongside the cost of building, including the cost of meeting the need with flexibility for a defined period. Substantial augmentation should be staged against observed demand triggers rather than approved once at the start of a period, through the gated pipeline described at Question 3. And where demand growth is uncertain, the option value of flexibility should be assessed explicitly.

Question 11: Does the RoRI enable appropriate compensation for risk within the context of the regulatory package as a whole?

1. Are emerging transition-related risks systematic or business-specific in nature?
2. Are TNSPs and DNSPs facing increasingly different risk profiles and, if so, are those differences relevant for the RoRI?
3. Does the current RoRI framework provide sufficient flexibility to reflect changes in systematic risk over time?

11.1 Are emerging transition-related risks systematic or business-specific?

There is a significant limitation in the scope of this question. It asks whether the Rate of Return Instrument provides sufficient flexibility to compensate networks for changing risk, but not whether the current parameters produce an efficient allowed return. Those questions cannot be separated. If the allowed return already exceeds the return required to finance an efficient network business, giving the AER greater capacity to respond to asserted new risks could increase rather than correct the existing imbalance. The Review should therefore consider both directions of error: under-compensation and over-compensation.

The transition risk of interest to Solar Citizens is that consumer-owned generation, storage and flexibility will substitute for network services and leave assets underutilised. How much of that risk any individual network faces depends substantially on its own decisions: export limits and

hosting capacity, connection terms, tariff structures, whether it procures flexibility or builds capacity and the reliability standards of its jurisdiction. Two networks facing similar consumer uptake can end up with materially different exposure depending on how they managed it. Therefore, much of the operational exposure is network-specific; only the part demonstrably systematic, material and not already compensated should affect the allowed return.

Before any transition-related risk affects the allowed return, the AER should be required to establish that the risk is systematic, material and not already compensated elsewhere in the regulatory package. A risk should not increase the allowed return where it can be managed through the network's own investment, procurement or operating decisions, or where consumers already bear it through cost pass-throughs, uncertainty mechanisms, expenditure allowances or shared stranding costs. Otherwise, consumers may pay twice for the same risk: first through the mechanism that transfers or shares the cost, and again through a higher return applied to the whole RAB.

11.2 Are TNSPs and DNSPs facing increasingly different risk profiles, and is that relevant to the RoRI?

The profiles are diverging, and distribution is more exposed to substitution than transmission because consumer resources substitute at the distribution level. Solar Citizens accepts the observation. We do not accept that this situation justifies a higher allowed return for distribution because the risk also creates a potential opportunity for CER to provide distribution flexibility (as discussed at numerous points in this submission).

Different exposure does not necessarily imply different systematic risk. A DNSP can reduce its exposure to substitution by procuring flexibility, increasing hosting capacity, avoiding premature augmentation and using staged investment. These are business decisions, not economy-wide risks. Nor should a higher return be used to compensate a DNSP for declining utilisation where the same distribution network has retained the option to build conventional capacity instead of procuring a lower-cost consumer service. The appropriate response is to correct the investment incentive and allocate the specific risk to the party best able to manage it.

11.3 Sufficient flexibility to reflect changes in systematic risk over time

The Rate of Return instrument (RoRI) is currently remade every four years with an extensive evidentiary process, expert input and independent panel review. Four years is adequate for the method, and Solar Citizens suggests the Commission resist both a shorter cycle and discretion to adjust the return between instruments. Systematic risk is a property of the economy, not of a technology cycle, and the allowed return applies to the whole asset base for the whole period, which makes it a material determinant of network charges.

The two-yearly simultaneous cycle recommended at Question 2 would improve how the instrument operates. At present it applies to networks commencing a regulatory period within the four years after its release, so two DNSPs of identical risk can receive different allowed returns depending on which year their period begins and what averaging period their cycle produces. Resetting revenue every two years shortens the period over which a DNSP is exposed to its own forecast error and so reduces the risk it bears. The return should recognise a reduction in risk as readily as it is asked to recognise an increase.

Support for a four-year instrument cycle should not be read as support for the present calibration of the RoRI. Stability in the method and accuracy in the allowed return are separate questions. Solar Citizens supports retaining the four-year cycle and opposes discretionary reopening between instruments, but the evidence used to set each instrument must include observed financing costs, actual returns and the performance of the previous instrument.

Observed results give the Commission reason to examine this question. IEEFA estimates that regulated electricity networks received around \$15 billion in supernormal profits between 2014 and 2023, in addition to \$17.6 billion in allowed equity returns, and that actual profit in 2022 was 2.5 times the level required to compensate for risk ([IEEFA, 2025](#)). These aggregate results do not establish that any single Rate of Return Instrument parameter caused the whole difference, but they do preclude an assumption that the present arrangements reliably self-correct or that the principal risk is under-compensation. The AEMC should not exclude the level and calibration of the allowed return from a review expressly examining the regulatory package as a whole.

Inflation treatment also requires examination. IEEFA notes that the AER has identified high inflation between 2022 and 2024 as an important cause of actual regulated equity returns exceeding allowed returns, while EMAS estimates that inflation variation produced a net gain to network businesses of around \$2 billion between 2015 and 2024. The issue is not whether networks should be protected from unexpected inflation while consumers bear unexpected disinflation, or vice versa. It is whether the present treatment is symmetrical over time and allocates inflation risk to the party best able to bear it without creating windfall gains. The next Rate of Return Instrument should be required to address that question expressly.

The AER should publish, for each network and each year, actual and allowed profit in dollars as well as percentages, with the contribution of inflation, debt costs, expenditure performance and incentive payments separately identified. The Commission should also examine a rule-based safeguard for persistent returns materially above the level required to compensate for risk. Any safeguard should be established in advance, apply according to published criteria, preserve transparent rewards earned under approved performance incentives and avoid giving the AER open-ended discretion to reopen the instrument between cycles. A predetermined correction of this kind is compatible with a stable four-year instrument; it is not an ad hoc change to the allowed return.

Question 12: Do you agree with our proposed assessment framework?

1. Do you agree with the proposed assessment criteria? Are there additional criteria that the Commission should consider or criteria included here that are not relevant?

Solar Citizens supports the proposed assessment criteria. In regards to the first criteria of outcomes for consumers, we suggest the Commission state, for each recommendation, what it has assumed about the uptake and capability of consumer energy resources. Recommendations premised on the distribution system of 2020 will fail against the system of 2035. Making the assumption explicit lets stakeholders test it and lets the recommendation be revisited if it proves incorrect.

Finally, Solar Citizens thanks the AEMC for the opportunity to make a submission, and we look forward to further engagement and consultation opportunities in the near future. Please don't hesitate to reach out should you have any questions about the content of this submission or wish to discuss the above recommendations.

A handwritten signature in blue ink, appearing to read 'Gabrielle Kuiper', with a long horizontal flourish extending to the right.

Dr Gabrielle Kuiper
Independent DER Specialist

A handwritten signature in black ink, appearing to read 'Heidi Douglas', with a long horizontal flourish extending to the right.

Heidi Lee Douglas
Chief Executive Officer, Solar Citizens

Acronym glossary

ARERA	Italy's energy, networks and environment regulator.
capex	Capital expenditure; spending on long-lived network assets.
CESS	Capital Expenditure Sharing Scheme; the AER's capex expenditure incentive.
DMIA	Demand Management Innovation Allowance.
DMIS	Demand Management Incentive Scheme.
DPP4	New Zealand's fourth default price-quality path for electricity DNSPs, covering 2025–30.
DSO	Distribution System Operator; here, active management functions proposed for distribution networks, not necessarily a separate organisation.
EBSS	Efficiency Benefit Sharing Scheme; the AER's opex expenditure incentive.
GME	Gestore dei Mercati Energetici, Italy's energy-market operator and host of the RomeFlex platform.
Ofgem	Great Britain's energy regulator.
opex	Operating expenditure; spending to operate and maintain a network, including contracted services.
RAB	Regulated asset base; the value on which a network earns a regulated return and recovers depreciation.
RIIO	Ofgem's network price-control approach: Revenue = Incentives + Innovation + Outputs.
RoRI	Rate of Return Instrument; sets the method for calculating regulated networks' allowed return.
ROSS	Italy's method for regulating network expenditure and service outcomes. Basic ROSS uses total-expenditure incentives; Full ROSS adds forward-looking business plans for selected large operators.
totex	Total expenditure: capex and opex combined. A predetermined share can be recovered promptly as "fast money", with the remainder added to the RAB as "slow money".