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Unlocking the clean energy potential of Australian business rooftops

Barriers to uptake of solar and storage in business and community buildings and how to overcome them

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Key Findings

C&I solar and storage has significant untapped potential in Australia. Installed C&I solar capacity stands at 5.6GW, forecasts point to 17–31GW by 2050, and the technical rooftop potential could be even higher.

A range of barriers are constraining uptake, including business-level investment barriers, complex and inconsistent network tariffs, and slow, unpredictable grid connection processes.

These barriers can be overcome through improved incentive schemes, reviewed and standardised network tariffs, a streamlined grid connection process, and a first-principles review of distribution network economic regulation.

Unlocking the C&I solar and storage sector could help accelerate renewable supply and storage additions, serve business energy demand, and reduce energy costs for businesses.

Executive summary

Australian households are playing a leading role in Australia's transition to renewable energy, with the power-generating capacity installed on household roofs roughly equal to that of coal power stations.[1] In addition, almost half a million small-scale batteries will have been installed in the first year of the federal government's Cheaper Home Batteries Program.[2] However, we have not seen the same scale of action in Australia's commercial and industrial (C&I) sector even though it consumes substantially more electricity than the household sector, and that usage is biased towards daytime solar hours. Just 5.6 gigawatts (GW) of solar is installed on C&I premises today against a forecast capacity of 17–31GW by 2050, and the technical rooftop potential could be even higher still. C&I storage deployment is well behind households, though demand is increasing quickly.

For the purposes of this report, the C&I sector encompasses any non-residential, non-utility energy user, from manufacturers and retailers to farms, hospitals, and schools. This sector could play a far larger role in accelerating Australia's energy transition; in fact, it must play a larger role if the country is to meet its renewable energy targets. The National Energy Market (NEM) and Western Australia's South West Interconnected System (SWIS) grids are tracking below the pace of renewable supply additions needed to meet the 82% renewables target, and C&I solar can help fill that gap. It can be deployed faster than utility-scale alternatives, because it generally doesn't require extensive planning and environmental approval processes, nor new transmission build that can add several years to the roll-out of utility-scale power projects. It is also well suited to serving typical business demand profiles, supports energy cost reductions and competitiveness for businesses, and contributes to emissions-reduction goals.

Despite the significant market potential and benefits, C&I solar and storage continues to have low annual installation levels, as it is constrained by four key barriers. These key barriers were identified by IEEFA through interviews with stakeholders and our own analysis.

a) Business-level investment barriers

There are a number of business-level investment barriers constraining C&I solar and storage uptake.

- As has been well documented in historical research into investment in energy efficiency, because C&I solar and storage investments are usually deemed non-core business expenditure, managers tend to apply high return thresholds for these investments above the actual cost of capital.[3]

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[1] Across the NEM and SWIS combined there is 22GW of residential rooftop capacity according to GEM 2026 analysis based on CER STC registry data. Coal capacity source: CEC. Rooftop Solar and Storage Report: July to December 2025. February 2026.
[2] Green Energy Markets. 2026. Note this includes residential and small business, but the vast majority is residential.
[3] International Energy Agency (IEA). Mind the Gap – Quantifying Principal-Agent Problems in Energy Efficiency. October 2007; Energy Policy. Barriers within firms to energy-efficient investments. *DeCanio, S.* Vol 21. Pages 906-914. September 1993.

- As most businesses rent their premises, landlords will usually be the final decision-makers on solar and battery investments. Yet because the landlord doesn't pay the energy bill, they see little to no financial benefit from these systems, so have limited incentive to help drive the project forward. Tenants are also often on leases shorter than the life of a solar and storage asset, meaning they often cannot capture the full return on an investment they fund themselves.

- In many cases, government incentive schemes intended to correct for the negative externality of carbon pollution exclude the C&I sector or are being phased out. C&I is effectively the "missing middle" because systems are typically too large for residential incentives, such as the Cheaper Home Batteries Program, but too small for the utility-scale Capacity Investment Scheme. The value provided by certificates under the federal government's Renewable Energy Target – via Large-scale Generation Certificates (LGCs) and Small-scale Technology Certificates (STCs) – is declining rapidly. This means C&I solar systems receive significantly less support than previously, and the support they do receive is generally well below the value of carbon abatement estimated by the Australian Energy Regulator (AER).[4]

To help counter the sub-optimal level of investment in C&I solar and storage arising from these issues, governments need to develop a **comprehensive, long-term framework to drive decarbonisation of the electricity sector.** It should support all forms of zero-emissions energy, irrespective of scale, and the value of that support should align with the AER's guidance on the value of emissions reductions.[5] At the very least, policy support should align with the value paid for abatement under the federal government's Safeguard Mechanism. In the absence of a comprehensive decarbonisation framework, or as an interim step, governments should seek to address some of the holes in the existing, patchwork approach by **introducing incentives to help the "missing middle" of C&I solar and storage overcome business-level investment barriers.**

b) Complex and inconsistent network tariffs

Australia has 16 different distribution network service providers (DNSPs), each of which has been free to develop its own distinct network tariff structures.[6] The result a fragmented and inconsistent network tariff landscape for C&I distributed energy resource (DER) project proponents operating across DNSP boundaries. Tariff structures vary significantly across DNSPs, making it difficult for businesses to model investment returns, develop software and control systems to manage batteries, and develop nationally scalable business models. In this report, we examine demand charges, which can be up to 40% of business's electricity bills. We find they are inconsistently applied across DNSPs, differing based on the lasting cost of a single spike, when peak demand is measured, how

[4] Australian Energy Regulator (AER). Valuing emissions reduction – AER guidance and explanatory statement. May 2024. Page 4. With the exception of Victoria's VEU scheme which covers C&I solar.
[5] Ibid. Page 4.
[6] Three Victorian DNSPs – Powercor, CitiPower and United Energy – have shared ownership and have harmonised tariff structures. Ergon and Energex – both subsidiaries of Energy Queensland Limited – also have harmonised structures.

charges differ across seasons, and the complexity of the demand charge structure. This creates significant complexity and cost for C&I solar and storage providers (and electricity retailers). Further, the window in which demand charges are applied can often be so wide that it does not appear to adequately enable businesses to shift loads away from network peak periods. This could be reducing the ability of network tariffs to incentivise long-term network cost reductions.

Given this, **network tariff structures should be reviewed by the AER** to reduce the number of tariff structures, standardise them at a national level (or at least NEM-wide level) and ensure they send a clear incentive to consumers to manage their demand (or export power to the grid) where this could reduce the need for costly network upgrades. In addition, to prevent the complexity problem re-emerging, responsibility for tariff design should be given to the AER rather than individual DNSPs.

c) Inconsistent, slow and unpredictable grid connection processes

An inconsistent, slow and unpredictable grid connection process imposes material costs and delays on C&I projects. There is a lack of consistency in the grid connection processes and technical requirements for connection across DNSPs even though the technology involved is the same. In IEEFA's interviews, we heard reports of grid connection timelines ranging from a few months to a year or more for more complex projects or those with a number of iterations in the connection application process. We also heard reports of certain Australian DNSPs regularly taking longer than others to process applications. DNSPs retain discretion over specific technical requirements, meaning proponents can face different technical requirements for systems in different areas. Additional technical requirements can also emerge during the process rather than being stated upfront, creating iterative revision loops that compound delays and cost. There is also a lack of consistent and easily accessible information on the degree to which different parts of the network could host solar capacity, making it harder for consumers and the solar industry to make well informed decisions about where they should be pursuing solar projects. **The grid connection process should be streamlined,** through a range of measures outlined below:

- A fast-track connection pathway should be developed (similar to residential systems) for C&I projects that adhere to a standard technical architecture that mitigates power quality and safety risks. This should be developed by the Clean Energy Regulator's National Technical Regulator for Consumer Energy Resources with input from DNSPs and the C&I sector.

- Technical requirements should be harmonised across Australia (or at least NEM-wide) with the Clean Energy Regulator's National Technical Regulator for Consumer Energy Resources playing a key role.

- DNSPs should be required to publish granular data on DER hosting capacity by location via a national, publicly accessible online portal.

- DNSPs should be required to publish data on C&I grid connection application processing timeframes, which should be collated and compared as part of broader network reporting processes.

- DNSPs should be incentivised to process grid connection applications quickly.

d) Uneven playing field for DER-provided network services

Distributed solar and storage can deliver value to the network through services such as voltage support, congestion management, and reduced or deferred network augmentation. The Regulatory Investment Test for Distribution (RIT-D) includes an options screening process in which DNSPs judge whether technological competitors (such as C&I solar and storage) might do a better job of serving an identified network need than upgrading their own network assets (over which they have exclusive licence). However, how this process is run is largely not conducive to effective competition from non-network alternatives in the form of C&I solar and storage. Other elements of the economic regulation regime also appear to constrain the consideration of non-network alternatives such as DER. Australia is not alone in grappling with these issues – momentum is growing internationally towards reform of the economic regulation of electricity networks. **An independently led, first-principles review of the economic regulation of distribution networks should be undertaken.** This should examine the potential for non-network solutions such as DER to compete with traditional poles and wires investment.

Together, these structural barriers to C&I solar and storage investment are preventing the sector from reaching its full potential at speed. The recommendations in this report offer a set of solutions to address the barriers and enable the C&I sector to be scaled up at pace, helping serve demand as coal exits, and supporting Australia in attaining its emissions reduction goals while reducing energy costs for businesses.

Box 1: Key barriers and recommendations

Barriers	Recommendations
Business-level investment challenges	1. The federal government should develop a more comprehensive, long-term policy framework to drive decarbonisation of the electricity sector. In the absence of this, or as an interim step, governments should consider introducing incentives to help the "missing middle" of C&I solar and storage overcome business-level investment barriers.
Complex, inconsistent network tariffs	2. C&I network tariffs should be reviewed by the AER to substantially reduce the number of tariff structures, standardise tariffs at a national (or at least NEM) level, and ensure they send a clear, actionable incentive to consumers to manage their demand (or export power to the grid) where this could reduce the need for costly network upgrades.
Inconsistent, slow and unpredictable grid connection processes	3. The grid connection process should be streamlined. • A fast-track connection pathway should be developed (similar to residential systems) for C&I projects that adhere to a standard technical architecture that mitigates power quality and safety risks. This should be developed by the Clean Energy Regulator's National Technical Regulator for Consumer Energy Resources with input from DNSPs and the C&I sector. • Technical requirements should be harmonised across Australia (or at least NEM-wide) with the Clean Energy Regulator's National Technical Regulator for Consumer Energy Resources playing a key role. • DNSPs should be required to publish granular data on DER hosting capacity by location via a national, publicly accessible online portal. • DNSPs should be required to publish data on C&I grid connection application processing timeframes, which should be collated and compared as part of broader network reporting processes. • DNSPs should be incentivised to process grid connection applications quickly.
Uneven playing field for DER-provided network services	4. An independently led, first-principles review of the economic regulation of electricity distribution networks should be undertaken. This should examine the potential for non-network solutions such as DER to compete with traditional poles and wires investment.

Unlocking Australia's C&I solar and storage potential

C&I solar potential

Commercial and industrial (C&I) solar photovoltaic (PV) systems include rooftop, building-integrated and ground-mounted systems that help serve the host site's electricity load and can sometimes also export surplus electricity to the grid. For the purposes of this report, C&I solar and storage systems are considered to be those installed on the premises of any non-residential, non-utility entity, including private businesses, agricultural enterprises, public sector buildings, non-profit organisations and community facilities such as healthcare and aged care providers. They vary widely in size from not much bigger than a residential solar system to about 5 megawatts (MW), and in rare cases above 10MW.[7] For the purposes of this study, we have excluded consideration of power systems used in remote, off-grid applications, which have very different commercial and technical characteristics to grid-connected systems.

Across Australia's main grids, commercial solar PV systems (100 kilowatts [kW] or less) have an installed capacity of 4.3GW, while those above 100kW represent a cumulative capacity of about 1.3GW, giving a total market size of 5.6GW. The market has emerged mostly over the past decade, which could be largely attributed to significant reductions in solar PV system costs and an increase in the wholesale price of electricity in the National Electricity Market (NEM).[8,9]

After an initial growth spurt in the market in the mid 2010s, annual installations have flatlined at about 600MW in the 2020s.[10] Major sectors installing commercial solar PV include retail, commercial, logistics/warehousing and education according to analysis by Jacobs.[11] To date the 5.6GW of installed C&I solar capacity remains relatively low compared with the 22GW of residential rooftop solar across the NEM and Western Australia's South West Interconnected System (SWIS) to December 2025.[12] At about 600MW per year, annual installations in the C&I solar market over the past few years have substantially lagged behind the roughly 2,500MW per year the residential sector has recorded in the same period.[13]

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[7] Note: Systems up to 5MW are exempt from registering as a generator in the NEM. Systems 5MW–30MW typically must register as a market participant but may be exempt – subject to Australian Energy Market Operator (AEMO) discretion, and dependent on the quantity of exported energy and market treatment of exported energy. CitiPower, Powercor. National Electricity Law. Accessed 4 May 2026.
[8] Green Energy Markets (GEM). Projections for distributed energy resources – solar PV and stationary energy battery systems, Report for AEMO. December 2024.
[9] CSIRO. Small-scale solar PV and battery projections 2025-26. December 2025. Pages 45-46.
[10] GEM. Solar Report. 2026.
[11] Jacobs. Mid-scale Solar PV System Projections for the Clean Energy Regulator. 15 August 2024. Page iii.
[12] GEM 2026 analysis based on CER STC registry data. Note: This number deducts capacity from systems that have been retired or replaced, which is often not accounted for in data published from other sources such as the Australian Photovoltaic Institute.
[13] Ibid.

Table 1: Total installed capacity of C&I solar, 2026, Australia's main grids

	Smaller commercial PV systems (<100kW)	Larger commercial PV systems (>100kW)	Total
Market size	~4.3GW	~1.3GW	**~5.6**

Source: Green Energy Markets. Excludes small power stations – is only behind the meter (BTM) on main grid systems, e.g. NEM, SWIS, North West Interconnected System (NWIS) and Darwin-Katherine Interconnected System (DKIS).

Forecasts for Australia's total commercial PV capacity in 2050 range from 17GW (CSIRO) to 31GW (GEM). This represents the likely cumulative installation capacity in 2050, including existing systems. This capacity usually sits in two buckets: smaller than 100kW capacity and larger than 100kW. It should be noted that CSIRO includes some "small power stations" in its totals, which are outside the scope of this report as they are designed for electricity generation and sale into the wholesale spot market, rather than designed to help serve a business's energy demand.

Table 2: C&I solar capacity forecasts for 2050

Consultant	Smaller commercial PV systems (<100kW)	Larger commercial PV systems (>100kW)	Total
CSIRO (Step Change)[14] NEM and SWIS	~11GW	~6GW	**~17GW**
GEM Australian main grids	~21GW[15]	~10GW[16]	**~31GW**

Sources: CSIRO and GEM. Notes: CSIRO includes some "small power stations" in the >100kW capacity figures, and there is insufficient published data to break those out. However, GEM figures are all BTM C&I solar. CSIRO totals include NEM and SWIS. GEM figures include capacity in main grids of all states (NEM, SWIS, NWIS, DKIS).

These forecasts for the C&I solar sector show significant untapped potential in this market. The forecasts represent the consultant's expectations of where the market could go, however the technical rooftop potential for commercial PV is likely higher.

A 2019 University of Technology Sydney (UTS) study modelled the rooftop solar potential in Australia across various planning zones, finding 9GW in commercial/business, 19GW in industrial/utilities and 34GW in rural/primary production zones.[17] However, this was based on a historical PV panel density of 156.25 watts per square metre (W/m^2), while typical PV panel density in Australia in 2026 is approximately 215W/m^2.[18,19] When updating the PV capacity to account for 2026 panel density using a straight-line conversion, the new potential is 13GW in commercial/business, 26GW in industrial/utilities, and 47GW in rural/primary production. Much of the rural/primary production is likely to be C&I businesses. In total, the technical rooftop potential could be about 39GW (excluding rural/primary production) to 86GW (including rural/primary production).

[14] CSIRO. Small-scale solar PV and battery projections 2025-26. December 2025. Pages 45-46.
[15] GEM. Sub 100kW forecasts for the Australian Conservation Foundation (ACF). 2025.
[16] GEM. Forecast of BTM solar above 100kW. 2024.
[17] UTS, Australian PV Institute (APVI) and University of NSW. How much Rooftop Solar can be Installed in Australia? April 2019. Page 14.
[18] Ibid. Page 11.
[19] Why Solar. Solar Panel Sizes and Dimensions in Australia (2026). February 2026. Note: Average panel size 420W, dimensions 1,722 x 1,134mm = density of 215W/m^2.

It should be noted that not all rooftops in the given zones can be classified as "commercial/industrial" rooftops as these zones contain a mix of uses. For example, within these zones, residential rooftops could also be found. Conversely, commercial premises are also dotted through residential zones that were excluded from the UTS estimates. Further, some of these rooftops may not have an economically viable system option, and these estimates don't consider network hosting capacity. So, while these estimates are not perfect, they clearly show the technical potential for rooftop PV in these zones is very significant. This technical potential is rooftop solar only, and there would be additional technical potential in ground-mounted systems and in building integrated PV.

Table 3: Australian C&I rooftop solar technical potential, historical vs updated (GW)

Zone	UTS PV potential using historical PV panel density	IEEFA updated potential using 2026 PV panel density
Commercial/business	9.3	12.8
Industrial/utilities	19.0	26.2
Rural/primary production	33.9	46.7
Total	62.2	85.6
Commercial/business plus industrial/utilities	28.3	39.0

Sources: Institute for Sustainable Futures at UTS, the School of Photovoltaic and Renewable Energy Engineering at the University of NSW, and the Australian Photovoltaic Institute [20], and IEEFA calculations using updated PV panel density.

C&I storage potential

The installed capacity of commercial storage systems in the NEM is 276MW/263 megawatt hours (MWh) as of March 2026. This is quite low compared with the 2,787MW/5,057MWh in the NEM residential sector, which has grown significantly in the past year since the initiation of the Cheaper Home Batteries Program (CHBP).[21] Nonetheless, industry surveys show C&I battery demand has risen significantly – 82% of respondents reported increased demand last year.[22]

The potential for C&I storage has been less studied than the C&I solar potential. The Australian Energy Market Operator (AEMO) combines residential and small business batteries in its forecasts for the Integrated System Plan (ISP), meaning it is difficult to gauge AEMO's expectations of C&I storage uptake.[23]

Green Energy Markets (GEM) has forecast the Australian small business storage (<100kWh) capacity to reach 21GWh by 2050.[24] GEM anticipates that, "In the small commercial sector, we expect battery

[20] ISF, SPREE UNSW and APVI. How much Rooftop Solar can be Installed in Australia? April 2019. Page 14.
[21] AEMO. March 2026 DERR data. Reporting date 31 March 2026. Accessed 4 May 2026.
[22] Orkestra. Industry census unpacked: The real state of C&I solar in ANZ. 10 November 2025. Page 31.
[23] AEMO. Draft 2026 ISP Appendix A9. Demand Side Factors Statement. December 2025. Page 34.
[24] GEM. Sub 100kW forecasts for ACF. 2025.

systems will be around 50kWh in average size."[25] This forecast was developed early in the CHBP rollout and may not reflect current uptake trajectories.

In addition, there would be potential for larger C&I battery storage installations above 100kWh. An industry survey found the median modelled battery size in the C&I storage space was 250kW/500kWh, with about two hours being the most prevalent duration.[26]

The total technical potential for C&I battery systems could be quite large, as it is not constrained by rooftop availability and suitability – only a sufficient ground footprint is required to house batteries.

C&I solar and storage offers a range of benefits to the grid

C&I solar can help increase the pace of renewable supply additions

The NEM is facing significant delays with transmission projects and utility-scale renewables. All major transmission projects have been delayed relative to the 2024 ISP, and transmission costs have increased by up to 100% compared with the inputs to the 2024 ISP process.[27,28] AEMO anticipated fewer transmission projects in its recent draft 2026 ISP, compared with the previous iteration.[29]

The Draft 2026 ISP estimates the NEM needs 58GW of utility-scale solar and wind by 2030, up from the current baseline of 26GW – an increase of 32GW in roughly four years (FY2026-27 to FY2029-30) to reach 82% renewables in FY2029-30.[30,31] This averages about 8GW per year.[32] However, nationally, the best year of commissioning utility-scale renewables was 2021 with 3.8GW, while in 2025, 3.3GW was commissioned.[33] Australia needs to significantly increase the annual rate of installation of utility-scale renewables through acceleration of wind and solar.

Wind is a critical bottleneck: in 2025, 1,323MW of onshore wind capacity was installed nationally; while the best year, 2021 saw 1,746MW installed.[34] AEMO reduced its NEM-wide FY2029-30 wind capacity forecast from 39GW in the 2024 ISP to 26GW in the draft 2026 ISP, after taking into account updated wind capacity factors and other dynamics.[35,36,37] Current NEM wind capacity is 14GW; to reach 26GW in FY2029-30 would require about 3GW to be installed each year.[38]

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[25] GEM. A re-evaluation of the potential for growth in rooftop solar and small-scale batteries. August 2025. Page 14.
[26] Orkestra. Industry census unpacked: The real state of C&I solar in ANZ. 10 November 2025. Page 29.
[27] Modo Energy. 2026 ISP: Draft release signifies expanded role for BESS in the NEM. Accessed 4 May 2026.
[28] AEMO. 2025 Electricity Network Options Report. August 2025. Page 6.
[29] AEMO. Draft 2026 Integrated System Plan. December 2025. Page 20.
[30] Ibid. Page 12.
[31] OpenElectricity. Accessed 14 May 2026. 11.8GW utility solar and 14.3GW wind.
[32] From FY2026-27 to FY2029-30 inclusive. Baseline is as at 14 May 2026, so any additional installed in remainder of May and June will reduce the additions required.
[33] Clean Energy Council (CEC). Quarterly investment report: Large-scale renewable generation and storage. Q4, 2025. Page 11.
[34] CEC. Clean Energy Australia 2026. May 2026. Page 30.
[35] AEMO. 2024 ISP chart data. 26 June 2024.
[36] AEMO. Draft 2026 Integrated System Plan. December 2025. Page 12.
[37] Ibid. Page 25. "[...] higher wind output (that is, more energy for every MW of capacity compared to the 2024 ISP)".
[38] OpenElectricity. Accessed 14 May 2026.

AEMO's Draft 2026 ISP revised upwards its utility-scale solar forecast for the NEM, driven by falling capital costs and other factors, with installed capacity projected to reach 32GW by FY2029-30 – double the equivalent forecast in the 2024 ISP.[39,40] It currently sits at 11.8GW in the NEM – requiring about 5GW on average to be installed each year to meet the Draft 2026 ISP forecast.[41,42] While utility-scale batteries are being installed in the NEM at pace, the rate of utility-scale solar installation is well below that forecast in the Draft 2026 ISP (2.0GW was installed Australia-wide in 2025, 1.3GW in 2024, and 1.9GW in 2023).[43,44,45] One way to help deliver this fast solar installation is by focusing on the C&I sector.

Distributed solar does not face the same constraints as utility-scale solar. It generally doesn't require extensive planning and environmental approval processes, nor new transmission build that can add several years to the roll-out of utility-scale power projects. Distributed solar projects can be installed at a much faster pace than utility-scale solar – in months, rather than years.

The success of residential rooftop solar demonstrates how smaller distributed projects, with the right financial conditions, can be deployed at scale and with speed. Over the past few years, the residential rooftop sector installed roughly 2.5GW per year.[46] Further, distributed battery installations have surged since the introduction of the CHBP – almost half a million small-scale batteries will have been installed in the first year of the federal government's rebate program.[47]

Given the significant technical rooftop solar potential across Australia's C&I sector, and the fact that C&I solar faces fewer transmission and planning constraints than utility-scale projects, there is a strong opportunity to accelerate renewable capacity and storage additions. This could help meet the total solar and storage forecasts in the Draft 2026 ISP, reducing pressure on the utility-scale renewables and transmission build-out, and helping increase the pace of supply additions to meet renewables targets and emissions reduction goals.

C&I solar and storage is well suited to serving business demand

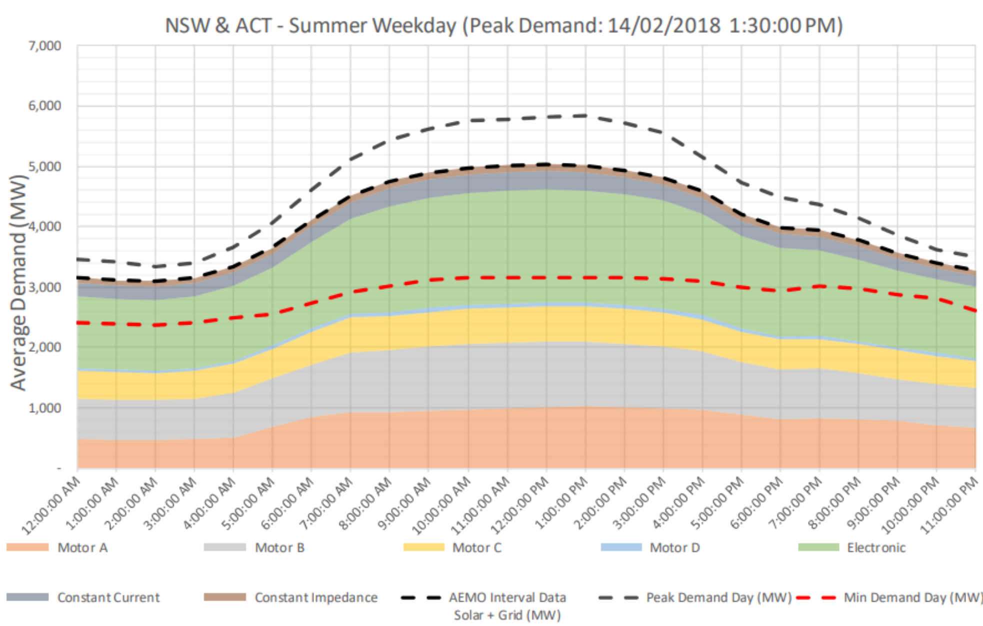
Commercial and industrial loads are different to residential loads: they tend to peak in the daytime, when business activity is at higher levels, rather than in the evening like in the residential sector. This can be well suited to a solar generation profile.

39 AEMO. Draft 2026 Integrated System Plan. December 2025. Page 12.
40 AEMO. 2024 ISP chart data. 26 June 2024. Figure shown is for capacity in FY2029-30 (Figure 2, utility solar, 2029-30 column).
41 OpenElectricity. Accessed 14 May 2026. Currently utility solar is 11.8GW.
42 From FY2026-27 to FY2029-30 inclusive. Baseline as at 21 May 2026, so any additional installed in remainder of May and June will reduce the additions required.
43 CEC. Clean Energy Australia 2026. May 2026. Page 6.
44 CEC. Quarterly Investment Report Q2 2025. August 2025. Page 5.
45 CEC. Clean Energy Australia 2025. May 2025. Page 3.
46 GEM 2026 analysis based on CER STC registry data. Note: This number deducts capacity from systems that have been retired or replaced, which is often not accounted for in data published by other sources such as the APVI.
47 GEM 2026 analysis. Note this includes residential and small business, but the vast majority is residential.

AEMO commissioned DeltaQ to estimate the composition of "commercial load" in the NEM, including loads such as small manufacturing, office buildings, shopping centres, warehouses, hospitals, schools, universities and hotels.[48,49] Reading the DeltaQ charts, the average summer weekday loads in NSW and ACT were highest around 10am–2pm (squarely in the solar generation period). The daytime NSW and ACT winter weekday load was typically lower than the summer weekday load and reached its maximum levels around 9am (also in the solar period).[50]

The study found peak demand in NSW and ACT occurred at 1.30pm.[51] This sits in the solar period. It also found that most peak demand times occurred on summer weekdays, and they correlated with the days that experienced the highest maximum temperatures. It concluded that, "peak demand events are largely driven by cooling equipment in the HVAC and refrigeration categories".[52]

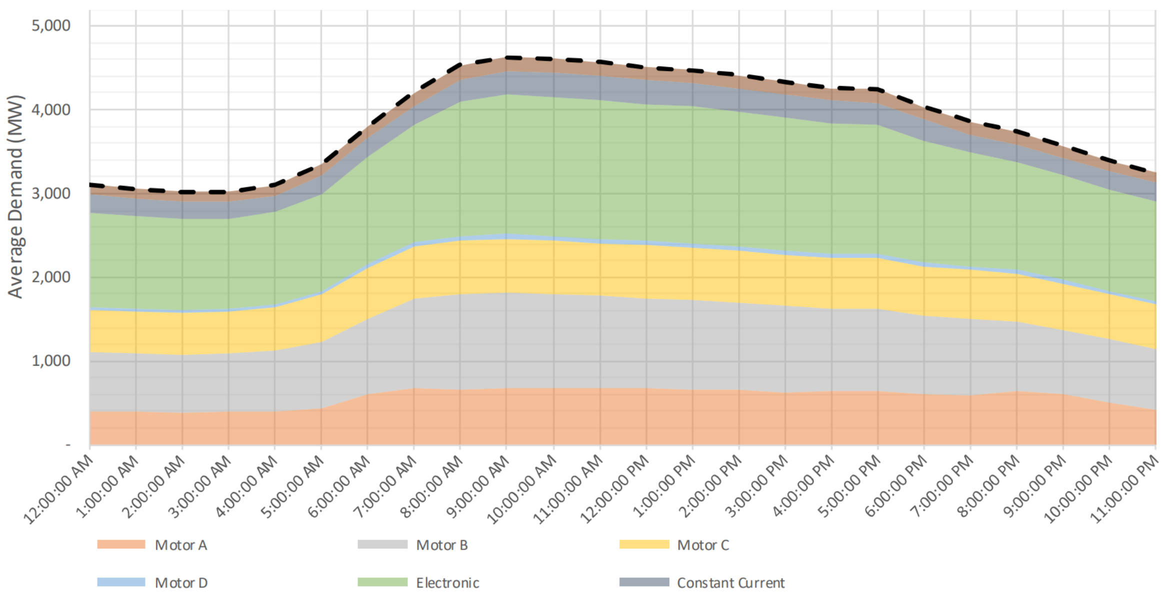
Figure 1: NSW and ACT average summer weekday demand vs peak and minimum (MW)



Source: DeltaQ.[53]

[48] Defined as a non-residential loads outside the largest ~220 industrial loads tracked by AEMO individually.
[49] DeltaQ. AEMO Commercial Load Model. 22 April 2020. Page 4.
[50] Ibid. Page 26.
[51] Ibid. Page 16.
[52] Ibid. Page 14.
[53] Ibid. Page 26.

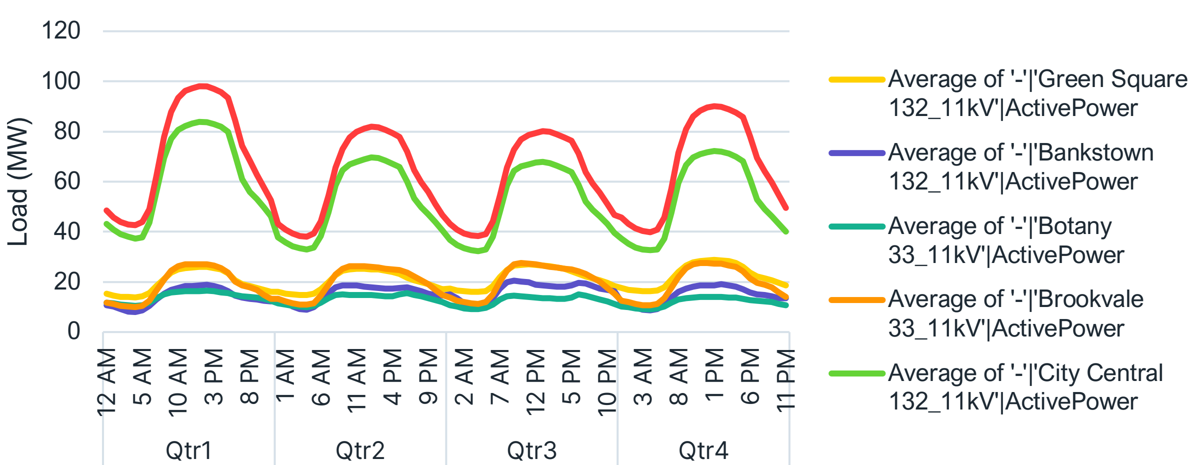
Figure 2: NSW and ACT average winter weekday power demand (MW)



Source: DeltaQ.

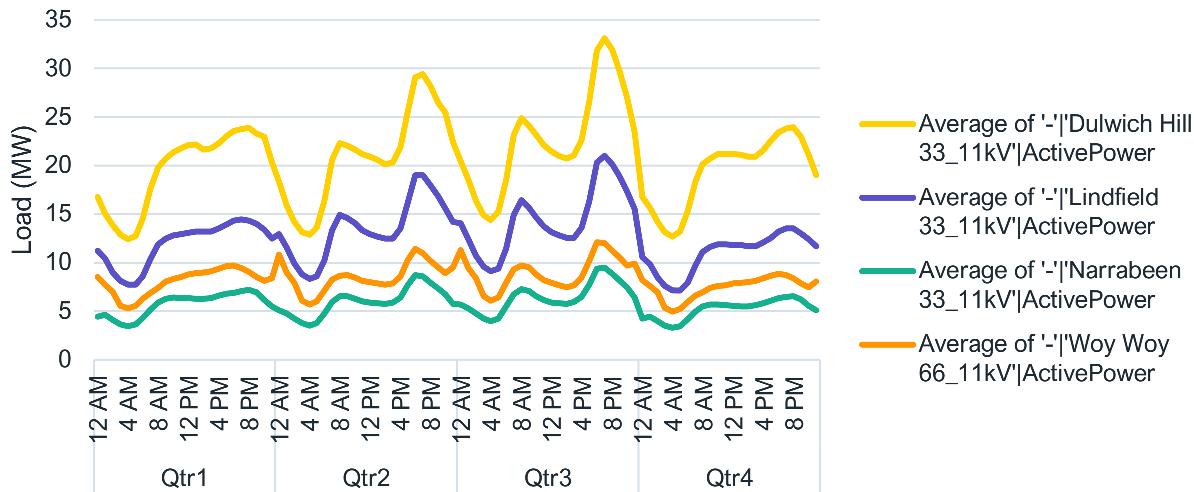
Figure 3 illustrates examples of distribution feeders from the NSW Ausgrid network that could be considered mostly "commercial/industrial", and those that could be considered mostly residential. C&I profiles tend to peak in the middle of the day, while residential profiles have a "double hump" – morning and evening peaks – often with low daytime demand due to residential solar. The C&I load profiles tend to be daytime-heavy, which would correspond reasonably well with solar profiles.

Figure 3: Sample primarily C&I feeder load profiles from Ausgrid network, 2015



Source: IEEFA analysis of Ausgrid load profiles.

Figure 4: Sample primarily residential feeder load profiles from Ausgrid network, 2015



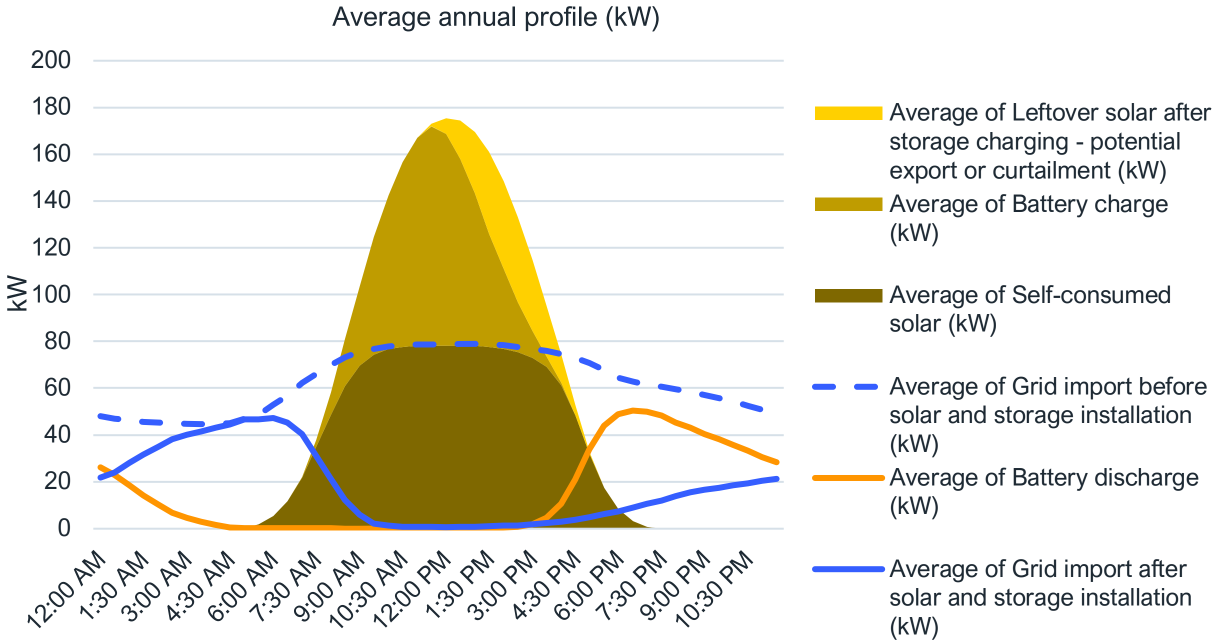
Source: IEEFA analysis of Ausgrid load profiles.

We can consider the impact of adding solar and storage to an illustrative C&I site to understand the impact on an individual load profile. Figure 5 provides an illustrative example of a C&I site load profile before and after solar and storage installation. This was developed by scaling down the Green Square feeder load profile to simulate a business using 1,500kWh/day (~550MWh/yr) with a 300kW solar PV system and a 500kWh/250kW battery (battery size in line with the median modelled industry battery size).[54]

As shown in the filled in blue line, their new average grid import is much lower than the original amount (shown in the dotted blue line). Self-consumption of solar and battery-stored solar has on average removed their contribution to daytime C&I peak demand. They typically only import in the morning and evening, consuming nothing from the grid in the middle of the day. If many systems like this were installed in a daytime-peaking commercial feeder, the regular peak daytime load on the feeder would likely be reduced. This has the potential to take pressure off network augmentation requirements.

[54] Orkestra. Industry census unpacked: The real state of C&I solar in ANZ. 10 November 2025. Page 29.

Figure 5: Sample C&I site load profile before and after solar and storage installation



Source: IEEFA analysis. Note: Green Square load profile scaled down to simulate the profile of a site using 1,500kWh/day (~550MWh/yr) with 300kW solar and a 250kW/500kWh battery. The battery in this example is optimised for self-consumption.

C&I solar and storage offers a range of additional benefits

As explored above, C&I solar and storage installations could quickly add more generation capacity and help serve business loads in distribution networks. It can deliver further benefits to businesses and the electricity system as outlined below:

- **Reduce business energy costs.** Solar and storage can bring down energy costs for businesses and insulate them against the risk of electricity price rises, making them more competitive. Solar Choice modelling shows commercial solar systems larger than 100kW achieve payback periods of 4.8–5.5 years with internal rates of return above 25%.[55]

- **No transmission build required for additional generation.** Installing more C&I solar in the distribution network generally does not require new transmission lines, while utility-scale solar usually requires transmission infrastructure for which costs have been rising.

[55] Solar Choice. Payback Periods for Commercial-Scale Solar PV Systems: State by State. October 2025.

- **Help serve demand as coal exits**. C&I solar and storage can help serve existing demand and new demand such as electric vehicle charging, data centres and industrial electrification. Adding additional generation sources is critical to help serve demand as coal exits.

- **Help meet emission reduction goals.** Accelerating C&I solar can also help meet emissions reduction goals.

- **Take pressure off the wholesale market.** Solar alone can reduce wholesale prices during daytime generation periods, while solar plus storage can take pressure off wholesale peak periods. This benefit could be accentuated if underutilised storage systems could export to the grid during the wholesale evening peak period. An Energeia study commissioned by the Australian Energy Market Commission (AEMC) found that if Consumer Energy Resources (CER) participated in wholesale and Frequency Control Ancillary Services (FCAS) markets and network demand response, AU$45 billion in benefits to 2050 (net present value) were possible (across residential and commercial customers). Energeia found that most system benefits would result from the avoidance of wholesale costs.[56]

C&I solar and storage is not without limitations or integration challenges. There are likely to be periods, particularly during prolonged cloud cover, when solar generation is low and batteries are fully discharged, leaving the business entirely reliant on the grid at full load. Additionally, if markets and systems are poorly co-ordinated, simultaneous export from multiple solar and storage systems could exacerbate minimum demand conditions. These scenarios do not undermine the case for C&I solar and storage but must be accounted for in system design, market design, standards and network planning.

Barriers to C&I solar and storage uptake

IEEFA identified a number of key barriers constraining the uptake of C&I solar and storage. These key barriers were identified through stakeholder interviews and desktop research.[57]

1. **Business-level investment barriers**
2. **Complex, inconsistent network tariffs**
3. **Inconsistent, slow and unpredictable grid connection processes**
4. **Uneven playing field for DER-provided network services**

[56] Energeia. Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Final Report. 26 March 2025. Page 4. Note, “over 80% of the potential benefits are expected to come from the residential sector, with the rest split between small and large commercial consumers. This is mainly due to the assumed, relatively high level of CER adopted by residential consumers compared to nonresidential consumers.”

[57] Climate Change Authority (CCA). Unlocking Australia’s clean energy potential. June 2025; Nexa Advisory. Untapped Potential of Commercial & Industrial Energy Resources in the NEM. September 2025; Federal Department of Climate Change, Energy, the Environment and Water (DCCEEW). Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024, and others.

In the following sections we explore each of these barriers in detail.

Business-level investment barriers

For C&I solar, the primary value stream is reducing onsite energy consumption charges. For storage, the primary value streams are electricity price arbitrage – optimising when the battery charges and discharges relative to electricity prices, load and solar generation – and there is potential to reduce demand charges. Additional value streams such as export feed-in tariffs (FiTs), certificate scheme revenue, FCAS market participation, wholesale demand response and network support services are available for C&I solar or storage projects on a case-by-case basis but are not reliably accessible across the sector. Key value streams are summarised in Table 4 below.

Table 4: Key value streams for C&I solar and storage projects

	Technology	Solar	Storage	Solar + Storage
Primary and secondary value streams	Reduction in energy consumption charges	✓	× None	✓
	Demand charge reduction (if site has demand charges)	✗	✓ Depends on demand charge structure	✓ Depends on demand charge structure
	Arbitrage (retail or wholesale if exposed via a VPP or other means)	✗	✓	✓
Additional potential value streams that may apply depending on project setup	Export FiT	✓ Limited / declining	O Limited / declining	✓ Limited / declining
	Certificates (STCs / LGCs)	✓ Declining	O <100kWh systems only	✓ Declining
	FCAS markets	✗	✓ Requires aggregation / market access	✓ Requires aggregation / market access
	Wholesale Demand Response Mechanism (WDRM) / demand response	✗	✓ Requires market access	✓ Requires market access
	Network support services	✗	O Location-specific, opportunistic	O Location-specific, opportunistic
	Improved blackout resilience	✓	✓	✓

Solar Choice's 2025 modelling of nearly 400 Australian business cases found that commercial solar above 100kW delivers payback periods of 4.8–5.5 years with internal rates of return (IRRs) typically above 25%.[58] By contrast, utility-scale solar has IRRs of 5–15% for investors.[59] C&I solar above 100kW therefore generates roughly 1.7–5 times the return of a utility-scale solar farm.[60] C&I storage can also have reasonable payback periods, as shown in Table 5. However, it should be noted that advanced battery revenues (and thus payback periods) can be uncertain.[61]

Table 5: C&I solar and/or storage payback periods

Technology	Payback period	Source
C&I solar	4.8–5.5 years (modelled)	Solar Choice[62]
C&I solar	5–7 years (industry experience)	Agile Energy[63]
C&I solar + batteries	3–5 years (industry experience)	Agile Energy[64]
C&I batteries	5–7 years (required by businesses to proceed)	Orkestra / PV Magazine Australia[65,66]
C&I batteries	5–8 years (typical reported outcome)	AR Energy[67]

Yet despite the superior financial returns, the scale of capacity installed in the C&I sector has significantly lagged that delivered by utility investors. A number of business-level investment challenges exist with the C&I solar and storage sector that inhibit investment, including:

- **Bounded rationality of managers**, which leads to severe rationing of capital for investments outside of their core business.
- **The high proportion of businesses that rent their premises**, with misaligned incentives between landlords, who are responsible for the building's permanent fittings and equipment, and tenants, who pay the energy bill. Adding to this is the misalignment between solar and storage asset lives and typical lease terms.
- **Emissions reduction policies** that either explicitly exclude support for C&I solar and battery systems, or usually severely undervalue the emissions reduction benefits of these systems.

The following sections explore each of these topics.

58 Solar Choice. Payback periods for commercial-scale solar PV systems: State by state. 13 October 2025.
59 CBRE. Australia's Renewable Energy Market is Set to Deliver Value for Investors. 14 May 2025.
60 These figures are directional comparisons using different methodologies across different asset classes and should not be interpreted as a precise financial equivalence. C&I IRR figures are derived from payback period analysis on 15–25 year asset lives; utility-scale IRR figures reflect discounted cash-flow modelling across 25–30 year project lives with contracted revenue.
61 Orkestra. Industry census unpacked: The real state of C&I solar in ANZ. 10 November 2025.
62 Solar Choice. Payback periods for commercial-scale solar PV systems: State by state. 13 October 2025.
63 Agile Energy. Agile Advantage: Unlocking Full Value from Solar & Storage - The Business Case for Batteries. November 2025.
64 Ibid.
65 Orkestra. Industry census unpacked: The real state of C&I solar in ANZ. 10 November 2025.
66 PV Magazine Australia. Survey shows battery boom extends to C&I sector. September 2025.
67 AR Energy. Commercial Solar Batteries in Australia: Costs, Benefits, and ROI.

Capital rationing to non-core business investments

Business managers, just like all human beings, are constrained in their ability to process and evaluate information about their firm's operations and investment options. As detailed in the Nobel Prize in Economics winning work of Herbert Simon, business managers don't manage their businesses by perfectly optimising every possible factor influencing their business but rather by "satisficing" – they make rational decisions that are bounded by their cognitive limits (known as "bounded rationality").[68] Research focused on understanding business decisions on energy efficiency investments found that one way managers ration their limited attention is by deprioritising investments outside their core business activities. In practice, this means they only consider investments in non-core activities such as energy efficiency where investment returns are well above their cost of capital.[69]

Energy generation investments, just like energy efficiency, are not the core activity of most C&I businesses. Feedback from IEEFA's industry interviews indicates that a solar project with a high IRR can still lose out compared with other business investments, not because the financials are unfavourable, but because the project sits outside the business's day-to-day operations and core focus.[70] This is outlined by solar and battery software business Orkestra below:

"The Capital Allocation Challenge: Unlike core business assets, solar energy projects often compete against other essential capital expenditure that offer more immediate, and more often, obvious core business returns. Without a substantial subsidy to de-risk the investment and shorten the payback, energy projects frequently fail to win the necessary internal funding despite its importance, stalling otherwise financially sound projects."[71]

The rationing of capital to non-core business investments is a structural issue that constrains investment in C&I solar and storage to economically sub-optimal levels. Financing structures such as power purchase agreements (PPAs) and solar leases have emerged to help overcome capital rationing.[72] However, they still come up against the problem that managers seek to ration their attention, not just their capital, to non-core business opportunities. Navigating a PPA or solar lease still requires internal time, specialist knowledge and management attention. This is a meaningful burden for businesses without dedicated energy procurement resources, and a particular constraint for smaller C&I customers where transaction costs can be disproportionate relative to project size. PPAs are also generally only available to a subset of the market – as they generally require a credit-

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[68] Nobel Foundation. Rational Decision-Making in Business Organizations. Economics Nobel Prize Memorial Lecture. *Simon, H.* December 1978.
[69] IEA. Mind the Gap – Quantifying Principal-Agent Problems in Energy Efficiency. October 2007; Energy Policy. Barriers within firms to energy-efficient investments. *DeCanio, S*. Vol 21. Pages 906-914. September 1993.
[70] IEEFA interviews with C&I solar and storage stakeholders.
[71] Orkestra. Solar VIC's Game-Changer Discount for C&I Businesses. 14 October 2025.
[72] Orkestra. Industry census unpacked: The real state of C&I solar in ANZ. 10 November 2025. Page 44.

worthy tenant, a long lease, and binding landlord consent that survives a change of ownership.[73] They also do not fully resolve the other barriers explored below.

Misalignment between tenant and landlord incentives, and lease term and asset life

In the C&I solar and storage space, projects are delivered through a range of ownership models. Where a business owns its premises, the typical approach is direct customer ownership, where the business funds the installation and captures the full financial benefit through lower power bills. However, a significant proportion of commercial and industrial premises in Australia are leased rather than owner-occupied.[74] Tenanted properties face two key limitations to investment in solar and storage: misaligned incentives between landlords and tenants, and misalignment of lease terms with solar and storage asset lives.

Firstly, the misaligned incentive between landlord and tenant exists because the landlord owns the building and is the final decision-maker on upgrades. The landlord, however, does not usually pay electricity bills, and therefore does not benefit directly from lower energy costs arising from solar and storage. Meanwhile, the tenant rents the building and may want certain energy upgrades, and they typically receive the largest financial benefit in the form of reduced energy bills. However, they do not have the final decision-making power.

While landlords may gain from a potential uplift in rent and building value, they do not benefit immediately from reduced energy bills and so may have limited incentive to drive projects forward. Despite this, the landlord needs to consent to the system being installed and engage in the transaction. If the landlord does not see the value in it for them, or does not have the time to engage, this can block or delay projects, even if the project financials are strong.

The second key tenancy limitation is the misalignment between asset lives and lease terms. Solar and battery systems can have design lives or component warranties of 10–25 years and payback periods of 3-8 years (as explored above). However, commercial leases in Australia commonly run for 3–5 years for smaller tenancies and about 10 years for major tenants, and are often subject to renewal uncertainty.[75] This mismatch creates risk across all parties: a tenant may benefit from lower energy bills for a period but faces the possibility of their lease not being renewed before the asset has paid back its cost. Meanwhile, a landlord may benefit from uplifted rent or property value in the future but might not be able to rely on new tenants being willing to help pay for an existing system, and a financier or developer could also be exposed, depending on the project structure. The costs,

[73] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[74] PV Magazine Australia. Storage and Solar 'As-a-Service' Venture Hits Australia's C&I Segment. 23 October 2024.
[75] Baker McKenzie. Commercial Leases - Australia: Global Corporate Real Estate Guide. 2025. “The typical term of a commercial lease for commercial premises is usually between three and five years for smaller tenancies and approximately 10 years for major tenants, with or without option rights in favour of the tenant to extend.”

benefits and time horizons of the investment rarely align neatly between the parties, and the shorter and less certain the lease, the harder it is to build a financeable business case.

The industry has developed a range of models that can partially address some of these challenges.

PPAs allow a third-party developer to fund, own and operate the solar and/or storage asset, charging the occupant for the energy generated rather than requiring capital outlay from the tenant or landlord. However, for a PPA to be written at an acceptable rate, the tenor typically needs to be longer than the lease term for smaller tenancies (about 3–5 years).[76,77] PPAs may be an option for longer-tenure tenancies, but even these carry the risk of early termination. If the tenancy ends before the PPA term, complications can arise around early termination liability, asset removal and residual value – risks that can deter landlords, tenants and developers from entering these arrangements.

Environmental Upgrade Agreements (EUAs) are a council-based financing mechanism available in NSW, Victoria and South Australia, under which a building owner borrows to fund an environmental upgrade (such as solar) and repays the upgrade loan via a charge on council rates over up to 20 years.[78,79,80] For tenanted properties, an EUA allows the building owner to recover a portion of the project cost from tenants, typically being passed through under the lease, with tenants benefiting from lower electricity bills. The EUA charge is attached to the property rather than the occupant, meaning it transfers with ownership rather than tenancy. However, councils have historically lacked the knowledge and experience to offer EUAs to their communities.[81]

Further, to IEEFA's understanding, EUAs do not appear to resolve the underlying problem that short-tenure or departing tenants often lack the incentive or the time horizon to benefit from the upgrade in the first place, so they may have limited motivation to initiate such arrangements. Meanwhile, landlords do not directly benefit from lower energy bills – seeing only the more indirect benefits of possible rent uplift, improved building value, and green credentials – which may reduce their motivation to drive projects forward.

Embedded networks are a structural solution to the challenges presented by tenancy limitations for multi-tenanted properties. Embedded networks allow a third-party embedded network operator to own the solar or storage asset and on-sell electricity to tenants through a private network. The landlord can be compensated by the embedded network operator, helping resolve the landlord/tenant misaligned incentive issue. This model also resolves the misalignment between asset lives and lease terms, as incoming tenants can sign up to the embedded network and help contribute to the system cost repayment. However, embedded networks are only used in large, multi-tenanted

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[76] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[77] Baker McKenzie. Commercial Leases - Australia: Global Corporate Real Estate Guide. 2025. "The typical term of a commercial lease for commercial premises is usually between three and five years for smaller tenancies and approximately 10 years for major tenants, with or without option rights in favour of the tenant to extend."
[78] Australian Renewable Energy Agency (ARENA). Expansion of the Environmental Upgrade Agreement Market, Victoria. 2021.
[79] DCCEEW. Grants and Funding for Businesses. Accessed May 2026.
[80] ARENA. Scaling Up Environmental Upgrade Agreements Across Australia. May 2023.
[81] ARENA. Expansion of the Environmental Upgrade Agreement Market, Victoria. 2021.

properties with shared network infrastructure such as shopping centres and airports, and they are not applicable for the typical small-to-mid C&I tenant in a single-tenancy leased premises.

Green lease frameworks, which set minimum energy performance standards and mutual obligations between tenant and building owners, are another option, with the federal government mandating their use in certain federal office leases from 1 January 2025.[82] These are mostly focused on energy efficiency, such as the National Australian Built Environment Rating System (NABERS); however they could be expanded to include C&I solar and storage.

In summary, while various models have emerged to try to reconcile the misaligned incentives between landlords and tenants and the misalignment between asset life and lease terms, they face constraints that mean they can't comprehensively address the whole market. IEEFA interviewees indicated that misaligned incentives between tenant and landlords and the misalignment between lease term and asset life remain major inhibitors to the uptake of C&I solar and storage in many situations.[83]

Emissions reduction policies exclude or undervalue the C&I sector

The federal government, as well as some state governments, have implemented a range of policies that seek to drive emissions reductions. However, these policies sometimes specifically exclude large segments of the C&I sector. For example, the Capacity Investment Scheme (CIS) has historically excluded projects below 30MW in scale.[84] Meanwhile, the Small Scale Renewable Energy Scheme (SRES) is only available to solar systems up to 100kW in size and only up to 100kWh for batteries (with incentives cutting out at 50kWh).[85] The Safeguard Mechanism, meanwhile, only covers Scope 1 (direct) emissions and only applies to a small number of Australian businesses.[86]

For this reason, the C&I solar and storage sector is considered the "missing middle" – too big for residential schemes, and too small for utility-scale schemes. Some states have begun to fill in this "missing middle", such as Victoria and NSW, but significant gaps remain.

[82] Australian government, Department of Finance. Green Lease Schedules. 2025.
[83] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[84] Clayton Utz. Federal Government's new $10 billion Capacity Investment Scheme. 28 September 2023.
[85] DCCEEW. Cheaper Home Batteries Program. 2025.
[86] DCCEEW. Safeguard Mechanism Overview. Accessed June 2026.

Table 6: Solar and storage incentives across sectors

	Residential	C&I ("The missing middle")	Utility-scale
Solar	• **Federal STCs** provide an upfront rebate for systems ≤100kW. Support declining to zero by 2030.[87] • **Various state rebates** for residential solar available.	• **No CIS access.** • **Federal STCs** (≤100kW) or **LGCs** (>100kW and accredited as a power station). STCs support declines to zero by 2030; LGC revenue ceases after 2030.[88,89] • **Victoria** includes C&I solar in the Victorian Energy Upgrades scheme – accessing Victorian Energy Efficiency Certificates (VEECs) upfront, for energy used onsite (not exported).[90,91] Systems 30–200kW can access deemed VEECs while systems >200kW can access the measurement and verification method.[92]	• **Federal LGCs.** • **Federal CIS** revenue underwriting ≥30MW.[93]
Storage	• **Federal CHBP STCs** provide an upfront rebate for 5–100kWh batteries paired with solar. Discount tiered by battery size – full support for systems up to 14kWh, tapering for larger systems. Support declines to 2030.[94] • **NSW VPP incentive** via the PDRS for battery storage ≤28kWh that participates in VPP; federal rebate + PDRS VPP rebate can stack.[95,96,97]	• **No CIS access.** • **Federal CHBP STCs available for small systems** ≤100kWh only – does not apply to many C&I projects. • **NSW** is consulting on including C&I batteries 100kWh or 200kWh–5MW in the PDRS.[98]	• **Federal CIS** revenue underwriting for utility-scale dispatchable storage ≥30MW.[99]

[87] Clean Energy Regulator. Defining Small-Scale and Large-Scale Solar Systems. 6 February 2026.
[88] Ibid.
[89] Clean Energy Regulator. Large-Scale Generation Certificates. 6 February 2026.
[90] PV Magazine Australia. Victorian Efficiency Certificate Returns Boost Commercial Solar Investment. 17 October 2024.
[91] Victorian Department of Energy, Environment and Climate Action (DEECA). Commercial and Industrial Solar Photovoltaic System (Part 47). 2025. Pages 2 and 6.
[92] Ibid.
[93] DCCEEW. Capacity Investment Scheme South Australia-Victoria Tender. December 2023.
[94] DCCEEW. Cheaper Home Batteries Program. 2025.
[95] NSW Department of Climate Change, Energy, the Environment and Water (NSW DCCEEW). Install a Battery - Household Energy Saving Upgrades. 2025.
[96] NSW Minister for Energy and Climate Change. NSW & Commonwealth Double Incentives for Batteries. 10 June 2025.
[97] NSW Government. Virtual power plant (VPP) incentive. Accessed June 2026.
[98] NSW DCCEEW. ESS and PDRS Rule Change Consultation Paper. December 2025. Page 29.
[99] DCCEEW. Capacity Investment Scheme South Australia-Victoria Tender. December 2023. We note that Tender 8 of the CIS included aggregated projects into the bidding projects – "For this tender, aggregated projects refer to bids comprised of multiple stand-alone dispatchable projects, that together will deliver between 5 and 30 megawatts (MW) to the NEM." Through this, a C&I battery enrolled in a VPP could potentially qualify as part of an aggregated resource bid in Tender 8.

Where C&I solar is eligible for policy support – under the Large-Scale Renewable Energy Target (LRET) or under the Small Scale Renewable Energy Scheme (SRES) (where the system is 100kW or smaller) – the value of that support is rapidly diminishing, and these schemes will cease operation in 2030.[100,101] In relation to the SRES, solar systems are awarded certificates (STCs, which can be on-sold to electricity retailers for about AU$40 each) based on deemed levels of power generation only covering the years up until 2030. So for 2026, they are awarded certificates on installation covering their estimated or deemed generation from that year until 2030 (five years including 2030). A system installed in 2027 will only receive certificates recognising four years of generation. This is even though these solar systems are likely to generate power for 20 years, and the scheme originally awarded certificates covering 15 years of generation.

Solar systems greater than 100kW can create certificates (LGCs) for each MWh of electricity generated under the LRET scheme, which also ceases at the end of 2030.[102,103] Further undermining the effectiveness of this scheme is that the value of LGCs has dropped dramatically (Figure 6), so larger solar systems earn very little for their generation when they sell their certificates. In addition, C&I solar systems generally cannot access the federal government's CIS as they are too small or not registered market participants.

Figure 6: Large-scale Generation Certification (LGC) spot price

Source: GEM Renewable Energy Market and Investment Review (2026)

[100] Clean Energy Regulator. Defining Small-Scale and Large-Scale Solar Systems. 6 February 2026.
[101] Clean Energy Regulator. Eligibility for the Renewable Energy Target. 6 February 2026.
[102] Clean Energy Regulator. Large-Scale Generation Certificates. 30 October 2025.
[103] Clean Energy Regulator. Eligibility for the Renewable Energy Target. 6 February 2026.

With this piecemeal and dwindling solar PV support, Victoria has tried to plug the gap through the Victorian Energy Upgrades (VEU) program. This has been a significant boost to business cases for C&I solar in Victoria.[104] However, there is also administrative complexity associated with this program, particularly for C&I solar systems less than 200kW, which can create VEECs through the measurement and verification method, which is more involved than the deeming method used for systems that are 30–200kW.[105]

In theory, C&I solar systems could be supported under the federal Safeguard Mechanism (which values carbon abatement at about AU$35 per tonne of carbon dioxide [CO_2]) in circumstances where they produced energy that supplanted Scope 1 emissions on the site of a business facility covered by the scheme. This might happen where the site hosted a gas power station self-supplying power to the plant or where a gas boiler was replaced by an electric heat source. This raises the question: Why does it matter whether a solar system supplants onsite Scope 1 or 2 (indirect) emissions produced at a power station offsite? These emissions essentially have the same effect. Extending this logic further, government should be encouraging all businesses to reduce Scope 1 and 2 emissions, not just the small number of large emitting facilities covered by the Safeguard Mechanism.

It is worth noting the incentives in these schemes fall well short of the indicative value the AER placed on carbon abatement in 2024 (except VEECs, which only apply in Victoria).[106,107]

C&I storage remains a significant gap in incentives. The CHBP provides significant incentives for residential and business storage up to 100kWh and has been a resounding success. However, it has a sharp tapering in support for systems above 14kWh, and STCs are not provided for any capacity above 50kWh. The CIS supports utility-scale storage above 30MW. C&I systems usually fall through the gaps between the CHBP and the CIS. One state is considering how to address this – the NSW government is consulting on including C&I batteries in the Peak Demand Reduction Scheme (PDRS).[108]

Recommendation 1: Develop a more comprehensive, long-term policy framework to drive decarbonisation of the electricity sector – or introduce C&I incentives

Australia’s approach to driving emission reductions involves a patchwork of policy measures with a bunch of holes that mean we have failed to capitalise on the potential for solar and storage in the C&I sector to deliver cost-effective emissions reductions.

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[104] Orkestra. Solar VIC's Game-Changer Discount for C&I Businesses. 14 October 2025.
[105] Victorian DEECA. Commercial and Industrial Solar Photovoltaic System (Part 47). 2025. Page 12.
[106] Note: the STC value of $40/MWh is similar to the value of emissions reduction set by the AER, however it applies only for the first few years of the project’s life – as the scheme ends in 2030 – so therefore does not fully recognise the system for the value of emissions reductions it would provide.
[107] AER. Valuing emissions reduction AER guidance and explanatory statement. May 2024. Page 4.
[108] NSW DCCEEW. ESS and PDRS Rule Change Consultation Paper. December 2025. Page 27.

The Renewable Energy Target (RET) is due to end in 2030, not because electricity sector emissions will have been eliminated by then. Rather, when the 2030 end date was set in 2009, it was largely assumed the RET would be superseded by an economy-wide carbon price.[109,110] Today, the main policy mechanism to replace the RET and support renewable energy – the CIS – cuts off at 30MW, and the tenders will run for only approximately four years (with tenders being run from late 2023 to 2027).[111] Additionally, Australia's emissions trading scheme (the Safeguard Mechanism) doesn't cover the country's largest source of emissions – electricity generation. Further, none of the policy measures in place value emissions reductions in line with expert analysis of their worth (with the exception of VEECs).

Ideally, the federal government needs to develop a more strategic, comprehensive and long-term policy framework to drive decarbonisation of the electricity sector and the economy as a whole, rather than an incomplete patchwork of policies that have accumulated over time. This should deliver support not just to large utility-scale installations or the residential sector, but to all forms of zero-emission energy irrespective of their scale. These support mechanisms should ideally deliver a value of support in line with the Australian Energy Regulator's guidance on the value of emission reductions. At the very least, policy support should align with the value paid for abatement under the federal government's Safeguard Mechanism.

However, in lieu of taking the politically challenging path of carbon pricing, governments could at least seek to address some of the holes in the policy patchwork by **introducing incentives to support the "missing middle" of C&I solar and storage and help overcome business-level investment barriers.**

Options include:

- In line with the Climate Change Authority (CCA) recommendation, lift the capacity size thresholds for the SRES to support larger C&I solar and storage projects.[112]
- Modify the CIS such that it could provide a revenue underwriting mechanism via a streamlined pathway for projects below 5MW. This could provide a standing offer contract with a pre-specified floor price for C&I solar and storage projects that bypasses the main tender process.
- Improve state-based incentive schemes – taking the lead from Victoria in making C&I solar eligible for VEECs, and NSW in potentially including C&I storage in the PDRS.

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[109] Climate Change Authority. Renewable Energy Target Review. 2012. "A carbon pricing mechanism is in place and is intended, over time, to be the main instrument by which Australia achieves its greenhouse gas emissions reduction targets."
[110] A carbon price was subsequently legislated in 2012 but repealed two years later. Parliament of Australia. Clean Energy Legislation (Carbon Tax Repeal) Act 2014. 17 July 2014.
[111] The Energy. The Capacity Investment Scheme is getting bigger: here's how it works. 1 August 2025.
[112] CCA. Unlocking Australia's Clean Energy Potential. June 2025. Page 38.

- Consider increasing the instant asset write-off for systems and batteries over a certain size. This may appeal to landlords and increase the likelihood of upfront capital investment.

These options could help tip the economics in favour of adoption, helping overcome business-level investment barriers. Stronger financial incentives would lower the investment threshold to a point where C&I solar and storage can compete more effectively for capital against businesses' core operational priorities. They could also strengthen landlord and tenant incentives to pursue projects.

Complex, inconsistent network tariffs

The underlying network tariff is a structural determinant of key value streams for C&I solar and storage projects, such as reduction in energy consumption charges, electricity price arbitrage and potential reduction in demand charges. Network charges represent 30–60% of a typical C&I electricity bill.[113] Retailers pass network costs through to customers either bundled into a retail tariff (typical for smaller businesses), on a cost-pass-through basis (for larger businesses or cost-reflective retailers), or through site-specific negotiations for very large users. For small business offers, retail tariff structures generally follow network tariff structures, meaning network tariff structures have a strong bearing on the economics of C&I solar and storage.[114]

There are 13 DNSPs in the NEM. A further two operate in WA and one in the NT. For the purposes of this tariff analysis, we have focused on the NEM. Each DNSP sets its own tariff structures and prices, subject to AER approval, with prices updated annually. A tariff code identifies the pricing structure and rates that apply to a customer's connection point. Tariff code assignment depends on factors including consumption level, connection voltage, meter type, embedded network status, onsite generation and storage capability, and export capability. Note some businesses can have two tariff codes (for example, a main tariff code covering energy charges, demand charges and fixed charges, and a secondary tariff code covering export feed-in payments).

Across the 13 NEM DNSPs, IEEFA analysis indicates there between six (United Energy) and about 60 (Ergon Energy) business tariff codes in each network area. There are more than 250 business tariff codes across all NEM network areas (excluding residential, public lighting, unmetered and other such codes).[115] Each tariff code can carry multiple charge components, such as fixed charges, anytime energy or time-of-use energy, peak demand and export charges. These can vary in terms of how they are calculated or when they apply.

[113] Gridcog. Which network provides the strongest price signal for solar and batteries? 2020.
[114] Australian Energy Market Commission (AEMC). The Pricing Review: Electricity Pricing for a Consumer-Driven Future, Draft Report. 11 December 2025. Page 112. "We observe that most retail offers generally follow the same price structure as the network tariffs offered in that location."
[115] IEEFA analysis of AER data. Consolidated Stakeholder Report 2025–26. May 2025. IEEFA counted the tariff codes that apply to business customers. This excluded public lighting, control signal lights and nightwatch, and other such codes. It includes controlled load tariff codes (which are often detailed separate to standard tariff codes), embedded network codes and others. Note that some tariff codes have no customers.

A C&I solar and storage provider seeking to provide services to a comprehensive set of customers in the NEM must be across these 250+ tariff codes, for which the prices change each year, in order to feed them into system design, financial models, energy management and/or billing systems. This tariff complexity, alongside the fact each customer has a different load profile, means that every C&I solar and storage project requires tailored design, financial modelling and control strategies. There is no standardised approach applicable across the NEM. This drives up transaction costs, extends project timelines, and prevents installers, developers and financiers from building scalable, replicable models and marketing approaches. If a controller is configured for the wrong tariff structure (which could well be possible given the complexity), it could also prevent network cost minimisation for customers and for the grid overall, by leading the C&I site to draw or export power at the wrong times.

The significance of network tariff differences, and how they can affect a project's business case, was highlighted by DER software provider Gridcog back in 2020. It simulated the same C&I solar and battery project across 14 Australian DNSPs (the NEM plus Western Power in WA) and found network tariff savings differed by up to 150% – driven solely by network location.[116]

The three major components of network tariffs have significant inconsistency across DNSPs – including demand or capacity charges, volumetric energy consumption charges and fixed "standing" charges.

Demand charges are varied and complex

Demand charges apply for many medium and large C&I businesses. These charges are usually based on the highest measured demand recorded during a certain period. Demand charges can make up a significant portion of commercial electricity bills, in some cases up to 40%, and IEEFA's interviews indicate they can be even higher in some cases.[117,118,119] Demand charges are a potential monetisation mechanism for batteries.

It should be noted that terminology is inconsistent across networks – some use "demand charge" to describe both monthly and 12-month rolling maximum demand charge structures, while others use "capacity charge" specifically for charges based on maximum demand over a rolling 12-month window. The label alone does not reliably indicate the reset period.[120]

Table 7 compares demand or capacity charge structures for a representative "large" low-voltage (LV) C&I customer – for example, a business consuming approximately 160–750MWh a year connected to the LV distribution network, such as a large retail premises, a commercial office,

[116] Gridcog. Which Network Provides the Strongest Price Signal for Solar and Batteries? 2020.
[117] Park and Lappas. Evaluating demand charge reduction for commercial-scale solar PV coupled with battery storage. August 2017.
[118] Agile Energy. Agile Advantage: Unlocking Full Value from Solar & Storage: The Business Case for Batteries. November 2025.
[119] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[120] For example, CitiPower has a 12-month rolling demand charge and a summer incentive demand charge. Ausgrid, however, calls their 12-month rolling charge a capacity charge.

hospitality venue, small manufacturing facility or education facility. We have used one or two sample tariff codes per network for comparability, but note that some networks may apply multiple tariff codes for customers of similar size and consumption.[121] We have included key tariff codes for each network area that had a high number of customers and a demand or capacity charge component.

Table 7: NEM demand and capacity charge structures, large LV C&I customers (160-750MWh/yr), 2025-26

DNSP	State	Tariff (2025-26)	Demand / capacity charge component(s)	Calculation method and window
Ausgrid	NSW	EA305 LV 160–750MWh (system)	(1) Peak capacity – apparent capacity ¢/kVA/day	"A capacity charge is a price applied (in cents per kW or kVA per day) to the maximum half hourly kW or kVA demand reading that occurred in the period between 3 pm and 9 pm on a working weekday at a customer's connection point over the billing periods that relate to the previous 12 months including the current billing period" [122]
AusNet Services	Vic	NSP56 (160–400MWh) and NSP75 (400–750MWh) Med/lge critical peak demand	(1) Capacity $/kVA/yr (2) Critical peak demand $/kVA/yr	Capacity: annual maximum kVA (all year). Critical peak demand: average of five peaks recorded between 3–7pm on five summer (Dec-Mar) days nominated in advance.[123,124]
CitiPower	Vic	CLLVT Large low voltage	(1) 12-month rolling demand $/kVA/month (2) Incentive demand $/kVA/month	Rolling demand: highest 30 min kVA over prior 12 months, 7am–7pm workdays Incentive demand: highest monthly kVA, summer Dec–Mar, 1–4pm Minimum chargeable demand applies[125]
Endeavour Energy	NSW	N19 LV STOU Demand	(1) High season peak demand ¢/kVA/day – high season (monthly) (2) Low season peak demand c/kVA/day – low season (monthly)	"A monthly demand charge is payable, based on the highest demand (kW or kVA), which occurred within any half hour interval of that month consumed in a time period defined as 'High season Peak' or 'Low season Peak'" High season Nov–Mar, low season Apr–Oct[126]
Energex	Qld	SAC7200	(1) Peak demand $/kVA/month	"A monthly charge calculated as $/kVA/month, based on the maximum kVA demand measured as a single peak

[121] For example, Essential Energy has LV large business customers on a LV large business demand tariff (code BLND3AO shown in Table 7 above), LV large business demand-alternative tariff (BLND3TO), LV transitional demand tariff (BLNDTRS) and LV large storage/hybrid tariff (BLND4LS). Evoenergy has LV commercial customers on a General TOU tariff (codes 090, 091*), LV KW Demand tariff (106, 107), LV TOU kVA Demand (101, 104) and LV TOU Capacity (103, 105).
[122] Ausgrid. ES7 Network Price Guide. July 2025. Page 16.
[123] AusNet Services. Network Tariffs. 2025.
[124] Flow Power. Critical Peak Demand Explained. 16 September 2024.
[125] CitiPower/Powercor. 2025–26 Pricing Proposal. 28 March 2024. Pages 11–12.
[126] Endeavour Energy. Network Price List: Network Tariffs 2025–26. 15 May 2025. Pages 8–9 and 19.

		Large TOU Demand & Energy	(2) Shoulder demand $/kVA/month	over a 30 minute period during the peak demand charging window/timeframe." Peak: 5–8pm weekdays Shoulder: 1pm–5pm and 8pm–11am weekdays and 1pm–11am weekends[127]
Ergon Energy	Qld	ELTOUDT1 East Large TOU Demand & Energy	(1) Peak demand $/kVA/month (2) Shoulder demand $/kVA/month	"A monthly charge calculated as $/kVA/month, based on the maximum kVA demand measured as a single peak over a 30 minute period during the peak demand charging window/timeframe" Peak: 5–8pm weekdays Shoulder: 1pm–5pm, 8pm–11am weekdays, and 1pm–11am weekends[128]
Essential Energy	NSW	BLND3AO LV Large Business Demand	(1) Demand peak $/kVA (2) Demand shoulder $/kVA (3) Demand off peak $/kVA	Highest measured half-hour kVA demand in peak, shoulder and off-peak periods, monthly. Peak: 5–8pm weekdays Shoulder: 7pm–5pm, 8pm–10pm weekdays Off-peak: all other times[129]
Evoenergy	ACT	106, 107 LV KW Demand	(1) Peak demand ¢/kW/day	"7am-5pm weekdays Highest demand in a clocked 30-minute interval, starting on full or half hour, within bill period"[130]
Jemena	Vic	A30C[131] Large Business - LVCR <= 0.8GWh or LVEN <= 0.8GWh	(1) Annual demand charge $/kVA/year (2) Summer demand incentive charge c/kVA/Summer	Annual demand: "charging window is 8AM - 8PM weekdays (local time), Rolling 12 months" Summer Demand Incentive Charge: "charging window is 4PM - 7PM workdays (local time) each month in December to March, reset monthly"[132]
Powercor	Vic	LLV[133] Large Low Voltage	(1) 12-month rolling demand $/kVA/month (2) Incentive demand $/kVA/month	12-month rolling demand: "Maximum 15-minute kVA demand measured between 7am and 7pm local time on workdays over the prior 12 months" Incentive demand: "Summer incentive KVA is the maximum monthly 15-minute kVA for the December to March months. There is no charge for the other eight months of the year. Maximum monthly kVA is based on a fixed measurement period of either 1-4pm or 4-7pm on each workday of the applicable months." Minimum chargeable demand applies.[134]
SA Power Networks	SA	LBAD Large LV Business	(1) Annual kVA demand peak $/kVA	Annual demand peak: "Peak demand is measured as the highest daily average demand during the last 12 months November to March: CBD 11am-5pm, Rest of South

[127] Energex. Network Tariff Guide 2025–26. 1 July 2025. Page 18.
[128] Ergon Energy. Network Tariff Guide 2025–26. 1 July 2025. Page 25
[129] Essential Energy. Network Price List and Explanatory Notes 2025–26. July 2025. Pages 1, 7 and 10.
[130] Evoenergy. Schedule of Electricity Network Charges 2025-26. Pages 6–7.
[131] In the Jemena network, more customers are on the A300 transitional tariff. Tariff structure appears to be similar.
[132] Jemena. 2025–26 Network Tariff Schedule. 1 July 2025. Page 3.
[133] In the Powercor network, more customers are on the LLVT transitional tariff. Tariff structure appears to be similar.
[134] Powercor. Powercor 2025/26 pricing. Page 9.

		Annual demand	(2) Annual kVA demand anytime $/kVA	Australia 5pm-9pm. Peak demand values are billed all year round." Annual demand anytime: "Anytime demand is measured as the highest 30 minute demand interval during the last 12 months."[135]
Tas Networks	Tas	TAS89 Low voltage large business time of use demand	(1) Peak demand ¢/kVA/day (monthly) (2) Off peak demand ¢/kVA/day (monthly)	"For each monthly billing period, the peak demand-based charge is calculated by: (a) multiplying the peak demand-based charge by the number of days in the billing period; and (b) multiplying the amount calculated in (a) by the respective maximum demand recorded during the time of use peak period". The same method is applied to off-peak demand charge. Peak: weekdays 7-10am and 4-9pm Off-peak: Weekdays all times not covered above, weekends all day.[136] No energy charge – all network costs recovered through demand charges alone.
United Energy	Vic	LVkVATOU 1/ LVkVATOU 2 Large LV	(1) Rolling peak demand ¢/kVA/day or $/kVA/month (2) Summer incentive demand ¢/kVA/day or $/kVA/month	Rolling peak demand: highest 30 min kW (measured as kVA at max kW), 7am–7pm workdays, prior 12 months; Summer incentive demand: monthly maximum kVA (measured at monthly maximum kW value), 1–4pm or 4–7pm workdays, summer window Dec–Mar.[137]

Source: AER Consolidated Stakeholder Report 2025-26 and DNSP documents.[138] Notes: kVA = kilovolt-ampere. Tariff categories across networks might not be directly comparable (e.g. higher or lower demand levels), and this table is for illustrative example purposes only. Includes only NEM DNSPs. Where multiple tariff types exist for the given type of customer, tariffs presented here are those that include a demand or capacity component, and those with larger customer volumes allocated to them.

The key structural differences regarding how demand charges are calculated are:

- **The lasting cost of a single spike:** This is the most commercially significant difference. Under a monthly maximum demand charge calculation (e.g. Energex, Ergon, TasNetworks), one demand spike sets the charge for that month only. Under a rolling 12-month maximum "capacity charge" model (e.g. Ausgrid, CitiPower, Powercor, United Energy, Jemena), a single spike increases the chargeable demand for every billing period over a whole year. This makes it difficult for a battery to reduce demand charges without sustained 12-month performance.

- **When peak demand is measured:** Peak windows vary considerably across the NEM. Energex and Ergon have a narrow peak window at three hours per day over 5pm–8pm weekdays (and have shoulder demand charges). Endeavour Energy uses a two-season structure (high season: November–March; low season: April–October), with demand

[135] SA Power Networks. Large Business Network Tariff Information. 2025. Note some SAPN tariffs also have a monthly demand tariff.
[136] TasNetworks. Network Tariff Application Guide 2024–2029. Version 2.1. 16 June 2025. Pages 47–48 and 73.
[137] United Energy. 2024–25 Network Pricing. 28 March 2024. Page 10.
[138] AER. Consolidated Stakeholder Report 2025–26. May 2025.

measured during the relevant season's peak window each month. AusNet's critical peak demand structure is unique: it is calculated as the average of five peaks recorded between 3pm and 7pm on five summer days nominated in advance, meaning a business that successfully curtails demand on all five nominated days can significantly reduce its demand charge for a full 12 months.

- **Seasonality**: A range of distinct seasonal models operate simultaneously across the NEM. Energex and Ergon apply the same structure year-round. CitiPower, Powercor, Jemena and United Energy have both a summer incentive (December–March) and a rolling 12-month component.[139] Endeavour uses a two-season structure with different per-unit rates for high and low season. SA Power Networks measures peak demand in summer (November–March), and bills the resulting charge year-round, on top of a separate anytime demand charge. This shows significant variation in how seasonality is treated across networks.
- **Complexity of the structure:** Evoenergy uses a single demand charge component. SA Power Networks uses two (annual demand peak and anytime demand). Energex and Ergon also have two demand charge components (peak and shoulder). Essential Energy has three (peak, shoulder and off-peak demand charges). TasNetworks also applies two demand components (peak and off-peak) but is unique in recovering all network costs through demand and fixed charges alone in the TAS89 tariff – there is no energy charge component, meaning the entire bill must be managed through demand optimisation.[140] Ausnet applies both a critical peak demand charge and a capacity charge.

This complexity leads to different financial and operational optimisation strategies for C&I solar and storage projects, depending on their location and tariff. This directly suppresses the scalability of a hardware-software solution for the C&I sector. There is no standardised battery-control strategy to target a demand window; no standardised business case; no replicable financial model; and no consistent basis on which to train sales teams, develop financing products, or build software tools that work across all markets simultaneously.

Even so, the full complexity of network tariff codes is understated here as we explore just one tariff code (or in some cases, two) for each DNSP in Table 7. Within a single network, multiple tariff codes can apply to customers in the same consumption band. For example, Essential Energy has LV large business customers on a LV large business demand tariff (code BLND3AO in Table 7), LV large business demand-alternative tariff (BLND3TO), LV transitional demand tariff (BLNDTRS) and LV large storage/hybrid tariff (BLND4LS).[141] Evoenergy has LV commercial customers on a General TOU tariff (codes 090, 091*), LV KW Demand tariff (106, 107), LV TOU kVA Demand (101, 104) and LV TOU Capacity (103, 105).[142]

139 Three Victorian DNSPs – Powercor, CitiPower and United Energy have shared ownership and have harmonised tariff structures. Ergon and Energex – both subsidiaries of Energy Queensland Limited – also have harmonised structures.
140 TasNetworks does have other tariffs, e.g. TAS82, which has an energy charge in kWh and a demand charge.
141 AER. Essential Energy 2025–26 Final Standard Control Services Pricing Model. 30 April 2025.
142 AER. Evoenergy ED 2025–26 Final SCS Pricing Model. 31 March 2025.

Another issue emerges from analysis of the demand tariffs in Table 7. For many networks, the window during which the demand charge applies is so broad that it does not appear to incentivise or enable customers to shift load away from network peak periods. This could be reducing the ability of network tariffs to incentivise long-term network cost reductions. Examples include:

- **Year-round demand components:** Several networks apply a demand or capacity charge based on the customer's maximum demand over a rolling 12-month period, meaning a single peak event, even if not coincident with a network stress period, sets the customer's charge for the following year regardless of their behaviour in subsequent months. For example, Ausnet charges large business customers a capacity charge based on the annual maximum kVA recorded at any time across the full year, with no time window or seasonal restriction.[143] SAPN's LV large business annual demand tariff (LBAD) includes an "anytime" component measured as the highest 30-minute interval recorded across the entire prior 12 months, with no time window restriction.[144]

- **Lack of intra-day signals:** Endeavour Energy applies a monthly demand charge based on the highest half-hour demand interval recorded at any time of day during the month, with separate per-unit rates applying in high season (November–March) and low season (April–October). Unlike some other networks, there is no intraday peak window restricting when the chargeable demand can occur, meaning a demand spike at 3am carries the same weight as one during typical commercial feeder peak hours.

- **Broad peak demand windows:** For DNSPs with defined peak demand windows, some are very broad. For example, Jemena's annual demand charge spans 8am–8pm on weekdays, CitiPower/Powercor/United Energy's spans 7am–7pm workdays, and SAPN's anytime charge applies 24 hours a day, year-round (though it should be noted these networks also add a more specific charge with shorter time windows). The tariff elements that have wide time windows provide little price signal to guide when demand reduction is most valuable to the network, undermining the effectiveness of demand response and behind-the-meter storage as flexibility tools.

It should be noted that volumetric energy consumption charges with time of use signals are often layered on top of demand charges. These can provide additional signals for flexibility that could incentivise longer-term network cost reductions. However, these can also be applied inconsistently across networks.

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[143] Note: Ausnet has a critical peak demand layer that lies on top of this.
[144] SA Power Networks. Large Business Network Tariff Information. 2025. Note: SAPN also has an annual peak demand charge layered on top of this.

Volumetric energy and fixed charges also differ across networks

Just as demand charges vary significantly across networks, so too do fixed or "standing" charges and volumetric energy consumption charges.

Fixed charges differ materially in absolute terms across networks and tariffs. For example, United Energy's LVkVATOU tariff has no fixed charge, while Essential Energy's BLND3AO tariff (rural and regional NSW) carries an annual fixed charge of AU$7,531, and Ergon Energy's is AU$17,464 for the East Large TOU Demand & Energy tariff (ELTOUDT1).[145]

Energy consumption charges differ in rates and application, with flat "anytime" structures and peak, shoulder and off-peak structures. The timings for the peak, shoulder and off-peak energy consumption charges can differ across networks. For example, Evoenergy's peak volumetric energy charge window is applied over 10 hours from 7am–5pm on weekdays (for tariffs 101 and 104, LV TOU kVA Demand[146]), while Energex has a three-hour window from 5pm–8pm on weekdays (for tariff 7200, Large TOU Demand and Energy).[147] Many DNSPs offer flat "anytime" energy tariffs with no peak, off-peak or shoulder distinction for certain customers (such as small businesses).

The variations in volumetric energy consumption charges, combined with the demand charge variation and the fact load profiles vary across customers, mean the financial model and control strategy for a C&I solar and storage project is effectively rebuilt from scratch for every new network area – increasing costs for energy service providers. These differences mean an identical load profile could require different battery control strategies, and lead to different bills depending on the network area. For battery control, demand charge optimisation and volumetric energy charge optimisation should ideally occur in parallel to deliver bill savings. However, this is a complex equation that differs from network to network, and tariff to tariff.

As Flow Power noted in a submission to the AEMC Pricing Inquiry: "The number and structure of network tariffs differs between DNSPs, sometimes significantly, and they are reset every five years on a staggered basis. This creates complexity, costs and risks for retailers, energy service providers and large energy users, particularly those who operate across network areas." Flow recommended creating "one tariff structure setting process NEM-wide, with resulting tariff structures to apply across the board for a specific period, e.g. two years. […] Standardise tariff customer classes. Set a cap on the number of tariffs available under each customer class. In our view, no more than three tariffs are needed for each customer class."[148]

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[145] AER. Consolidated Stakeholder Report 2025–26. May 2025. Note these are the total network charges inclusive of distribution, transmission and jurisdictional scheme components.
[146] Evoenergy. Schedule of Electricity Network Charges 2025-26. Pages 5–7. Note: LV TOU kVA Demand tariffs (101 and 104) differ from that analysed in the demand charge discussion – LV KW Demand (106 and 107) – as the LV KW Demand tariff analysed in the demand charges section does not have a TOU energy consumption component.
[147] Energex. Network Tariff Guide 2025–26. 1 July 2025. Page 18.
[148] Flow Power. The Pricing Review - Flow Power Submission on Discussion Paper. 11 July 2025. Pages 3–4.

Recommendation 2: Review and standardise network tariffs

Distribution businesses currently set network tariffs individually, proposing their tariff structures through the Tariff Structure Statement, to which the AER then responds. This produces inconsistent network tariff structures across regions. This fragmented approach increases costs for energy service providers and limits the scalability of hardware-software solutions for the C&I market in Australia.

DeltaQ's NEM commercial load model found that most peak demand times occurred on summer weekdays and correlated with the days that experienced the highest maximum temperatures. DeltaQ concluded, "peak demand events are largely driven by cooling equipment in the HVAC and refrigeration categories".[149] IEEFA's analysis indicates that aggregated load profiles for substations look very similar across DNSPs for a given class of customers (residential versus C&I) and will usually peak based on cooling demand over hot days in summer.[150] This prompts the question as to whether there is much, if any, value to be gained by having tariffs separately designed by individual DNSPs.

Consequently, the AER should review C&I network tariffs to substantially reduce the number of tariff structures, standardise tariffs at a national (or at least NEM) level, and ensure they send a clear, actionable incentive to consumers to manage their demand (or export power to the grid) where this could reduce the need for costly network upgrades.

Ultimately, the tariff design process should be reformed to put the AER in charge of distribution network tariff design, setting standardised tariff structures nationally (or at least NEM-wide), informed by extensive stakeholder consultation.[151] Standardised network tariffs need to be designed with a focus on minimising the scope for poorly utilised and costly network upgrades. The AER's national and consumer-focused remit means it is better positioned than individual DNSPs to design harmonised tariff structures that reduce peak demand, contain network costs, and lower long-term infrastructure costs. Greater standardisation would lower transaction costs for energy service providers, enable broader consumer education, and strengthen the ability of businesses and installers to develop scalable C&I deployment models.

Inconsistent, slow and unpredictable grid connection process

The existing grid connection process

The grid connection process for C&I solar and storage projects depends on the capacity of the projects. Small projects below approximately 30kW have a streamlined process, while 30kW–5MW

[149] DeltaQ. AEMO Commercial Load Model. 22 April 2020. Page 14.
[150] IEEFA desktop analysis.
[151] IEEFA. Submission to Australian Energy Market Commission (AEMC) Electricity Pricing Review Discussion Paper. 10 July 2025. Pages 1–7.

projects fall under Chapter 5A of the National Electricity Rules (NER), and usually go through a negotiated process with the DNSP to connect to the grid.[152,153]

- **For systems below ~30kW,** DNSPs offer a streamlined connection process under a model standing offer, without requiring a negotiated connection agreement. The terms and conditions of these offers vary depending on the DNSP.[154]
- **Systems ~30–200kW** fall under Chapter 5A of the NER. They may use a negotiated connection process, but in some cases qualify for a basic (streamlined) connection service if a DNSP has approved one for that class of applicant.[155] Systems under 200kVA do not require interface protection unless specified by the DNSP.[156]
- **Systems 200kW–5MW** fall under Chapter 5A of the NER and typically use a negotiated connection process.[157] Dedicated interface protection equipment is required for systems in this range.[158] For systems at the larger end of this range, DNSPs also generally require network studies to be completed.[159]
- **Systems above 5MW** go through AEMO's connection process under Chapter 5 of the NER, and are required to register as a market participant. These are outside the scope of this report.[160]

Most C&I solar and storage system connections (30kW–5MW) are governed by Chapter 5A of the NER. The Chapter 5A connection process is outlined in Table 8 below. Networks are expected to process negotiated connections within 100 business days of the proponent submitting the initial connection enquiry (excluding potential requests for additional information).[161] This translates to 20 business weeks or about 4.5 calendar months of processing time.

However, these timelines are generally on a "best endeavours" or "if practicable" basis in the NER. In reality, they could be extended if iterations are required – for example, if the DNSP requires changes to be made to the application in line with certain requirements. They do not include the time

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[152] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 6.
[153] AEMO. Technical Requirements for 200 kW to 5 MW DER Connections. September 2024. Page 29.
[154] Global Sustainable Energy Solutions (GSES). How to Use Chapters 5 and 5A from NER for Large Scale Embedded Generators. 2 March 2022.
[155] For example, Energex. "If your connection qualifies as a basic connection service according to our Connection Policy (PDF 653.1 kb), (and Factsheet (PDF 1.3 mb)), our Model Standing Offer (PDF 369.9 kb) explains the applicable conditions for connecting your DER system to our electricity distribution network." Accessed May 2026.
Energex. Basic Connection Service Model Standing Offer: Connecting MEGU (IES >30 kVA–200 kVA) (Doc ID 13300797, Release 3). 28 August 2023. Page 4. EG 3 main grid 30-100kVA is available if maximum export is no more than 15kW. EG 4: main grid 100-200 kVA is available if export is no more than 30kW.
[156] Standards Australia. What's New in AS/NZS 4777.1:2024? Key Updates for Inverter Energy Systems. 25 September 2024.
[157] GSES. How to Use Chapters 5 and 5A from NER for Large Scale Embedded Generators. 2 March 2022.
[158] Energy Networks Australia. Inverter Installation Standards: What's New? March 2025.
[159] GSES. How to Use Chapters 5 and 5A from NER for Large Scale Embedded Generators. 2 March 2022.
[160] Ibid.
[161] GSES. How to Use Chapters 5 and 5A from NER for Large Scale Embedded Generators. 2 March 2022.

required by the applicant to do the work to provide information to DNSPs.[162] As consultants Oakley Greenwood noted, "the preliminary enquiry and connection offer are often iterative, and the site and technical characteristics of the facility may require changes due to network requirements".[163]

Table 8: NER Chapter 5A connection process

Step	Requirement	Timeframe/availability
Preliminary enquiry	When the applicant requests information, the DNSP must provide the information the applicant needs to make an informed application.	5 business days[164]
Application process	Application is made by the proponent. The proponent is responsible for providing the required information in the required formats. After receiving the complete application the DNSP must advise the applicant whether the connection service will be a basic connection service, standard connection service or a negotiated connection service. If it is a negotiated connection, the DNSP advises the applicant about the negotiated connection process and possible costs associated.	10 business days or as agreed between DNSP and applicant[165]
Potential additional step: Request for additional information	If a DNSP requires additional information to that provided in the application, it will request that information.	20 business days after receiving application (if practicable)[166]
Connection offer	For a negotiated connection offer, DNSP must use best endeavours to issue a connection offer within 65 business days after the date of receiving the application. *This excludes any time the applicant takes to provide additional information the DNSP requests.* If it is a basic or standard connection service, the DNSP must make a connection offer within 10 business days or as agreed.[167]	65 business days for a negotiated connection (best endeavours)[168]
Contract acceptance	Applicant has 20 business days to accept a negotiated connection offer before it lapses (45 business days to accept basic or standard connection offer).[169]	20 business days unless extended[170]
Contract performance	DNSP must use best endeavours to complete the connection works within the timeframes set in the contract.	As agreed in the contract (best endeavours)

Source: Oakley Greenwood study for DCCEEW, and the NER Version 93 Chapter 5A.[171,172]
Note: A dispute resolution process is also available through the AER, which is excluded from this table.

[162] GSES. How to Use Chapters 5 and 5A from NER for Large Scale Embedded Generators. 2 March 2022.
[163] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 7.
[164] AEMC. National Electricity Rules, Chapter 5A - Electricity Connection for Retail Customers, Version 93. Page 654.
[165] Ibid. Page 655.
[166] Ibid. Page 651.
[167] AEMC. National Electricity Rules, Chapter 5A - Electricity Connection for Retail Customers, Version 93. Page 661.
[168] Ibid. Page 662.
[169] Ibid. Pages 661 and 663.
[170] Ibid. Page 663.
[171] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 23.
[172] AEMC. National Electricity Rules, Chapter 5A - Electricity Connection for Retail Customers, Version 93. Pages 662–663.

Further, some DNSPs require additional assessment or information steps further to those mentioned above. For example, for C&I solar and storage from 501kVA to 4.99MVA, SAPN undertakes a high-level feasibility response (which could take 20 business days from receipt of all information and payment) and an engineering report (which could take 40 business days from receipt of all information and payment), before starting the connection offer step (which could take 65 business days from receipt of all information).[173,174] This amounts to 25 business weeks of application time, or about six months. This excludes time taken by the proponent to prepare the application, or any iterations.

In practice, the typical timelines from preliminary enquiry to connection agreement for C&I solar and storage projects have been approximated by renewable energy engineering consultant Global Sustainable Energy Solutions (GSES) at around 8-11 months.[175] In IEEFA's interviews, we heard reports of grid connection timelines ranging from a few months to a year or more for more complex projects or projects with a number of iterations in the grid connection process. We also heard reports of certain DNSPs regularly taking longer than others to process applications.[176]

The grid connection process can be affected by whether a system exports to the grid. IEEFA interviews indicated some zero-export or export-limited systems have been able to move through the connection process more quickly.[177] For example, Ausgrid does not require a network capacity assessment for sites with up to 200kVA of inverter capacity that limit export to no more than 30kW.[178] However, a faster zero-export process does not appear to be formalised and standardised across all DNSPs.

Challenges in the grid connection process

There are a number of challenges in the grid connection process, such as:

- **Site identification**: Proponents face difficulties in identifying suitable sites due to a lack of network visibility and information about available capacity.[179] This is particularly significant if they are a large capacity project that wishes to export.

- **Inconsistent technical requirements across DNSPs:** Under Chapter 5A, DNSPs have discretion over technical requirements for 200kW–5MW plants, meaning each DNSP tends to

[173] SA Power Networks. Large embedded generation. Frequently Asked Questions. Accessed 11 May 2026.
[174] SA Power Networks. NICC270: Connection of Medium and Large Embedded Generation Greater Than 30KVA Information Pack. 30 June 2025. Page 19.
[175] GSES. How to Use Chapters 5 and 5A from NER for Large Scale Embedded Generators. 2 March 2022.
[176] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[177] Ibid.
[178] Ausgrid. NS194 Embedded Generation. Revision 3, 30 March 2026. Page 7. "Sites with up to 200 kVA of connected inverter capacity, that limit export to no more than 30 kW will not require a network capacity assessment. If more than 30 kW can be exported from a site, Ausgrid will need to complete a network capacity assessment for any network supply point that will have, a total IES capacity of more than 30 kVA connected."
[179] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 2.

apply its own specific requirements.[180] AEMO has found: "While DNSPs usually specify most of the requirements identified in Section 2.4, specific requirements vary significantly between DNSPs"; and "While the results show commonality in the type of technical requirements applied, the performance levels vary across DNSPs."[181] For example:

- **Remote monitoring:** Thresholds differ significantly – some DNSPs require supervisory control and data acquisition (SCADA) at 200kW; others only above 1.5–2MW.[182]
- **Active power curtailment by remote signal:** This ranges from not required, to required above 1.5MW, to required for all sub-5MW systems. "Half DNSPs require active power control. Some implement this on a case-by-case basis, such as a run-back scheme. A small number do not require [it]."[183]
- **Ramp rate limits:** Some DNSPs impose no limit, most require 16.67% or 20% per minute, one requires a limit of 50kW per second.[184]

Inconsistent technical requirements across DNSPs add significant complexity to the grid connection process for developers. Industry consultants Illumine-i found that C&I solar and BESS applications routinely face grid approval delays of 4–10 weeks, with common causes of delay including missing or incomplete documents, outdated component specifications and non-compliance with technical requirements.[185] As technical requirements and documentation requirements differ across DNSPs, it would follow that there is an increased risk of non-compliant applications and subsequent redesign delays.

- **Additional technical requirements:** Additional technical requirements can emerge during the grid connection process, leading to additional costs or iterations. Oakley Greenwood found, "During the design work of the DNSP, specific technical requirements will be defined, which can require changes by the proponent. This […] may mean that specific equipment and other requirements are not known until the end of the 65-day period."[186] Some interviewees reported significant delays caused by technical requirements being advised by the DNSP in a piecemeal fashion over an extended time period rather than being stated upfront, causing significant delays.[187]

  One example of this is neutral voltage displacement (NVD) protection, which may be required for systems above an indicative threshold of 200kVA in the Evoenergy network in the ACT.

[180] AEMO. Technical Requirements for 200 kW to 5 MW DER Connections. September 2024. Page 29.
[181] AEMO. Technical Requirements for 200 kW to 5 MW DER Connections. September 2024. Page 27.
[182] Ibid. Appendix A3.
[183] Ibid. Page 50.
[184] Ibid. Page 51.
[185] Illumine-i. Grid Approvals: The Silent ROI Killer in Australian C&I Solar - And How to Fix It. 29 October 2025.
[186] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 25.
[187] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.

However, this is "determined on a case-by-case basis through a network technical study" so is not known at the start of the process. Evoenergy does not publish fees for this, stating only that, "more information regarding the requirements and fees associated with the configuration of inter-trip and NVD protection can be obtained by contacting Evoenergy".[188]

- **Iterative nature of the process:** Under the NER, if DNSPs require additional information after an application is submitted, they must request it within 20 business days.[189] The proponent then needs time to respond. The 65-business day period for DNSP to provide a negotiated connection offer only begins once all required information has been received. Even then, compliance is on a "best endeavours" basis, and excludes time taken by the applicant to provide the information.[190] Where multiple rounds of information requests occur, each adding several weeks, total timeframes can extend significantly.

- **Extensive network modelling:** For systems above 200kVA, network modelling studies – which may include power quality and harmonics assessments – are often required by DNSPs as part of the connection process (particularly for larger systems). This can add greatly to the cost and time associated with the grid connection process.[191] GSES states, "The longest process in connection applications under both chapters 5 and 5A is the steady-state and dynamic network modelling and analysis, usually undertaken in PSS®E, PSS®SINCAL, or PSCAD™ as specified by the DNSP."[192] AEMO's discussions with sub-5MW equipment manufacturers and developers concluded: "Modelling requirements can be burdensome and do not seem to add much value to the connection process. Examples of site-specific modelling leading to nearly identical outcomes were provided."[193]

- **Significant upfront costs**, which can differ across networks, and have the potential to escalate: For example, medium embedded generation in the SAPN network (31–500kVA) has fees for the network assessment (AU$5,499) and SCADA fees (AU$23,628). Larger systems in the SAPN network have a different fee schedule.[194] United Energy has a per-hour cost for client liaison, network planning assessments, protection assessments and other steps.[195] Costs associated with grid connection can escalate if certain revisions or additional studies are required.[196] Where network augmentation is needed, "it can take anywhere from

[188] Evoenergy. LV Embedded Generation Technical Requirements. 2025. Page 24.
[189] AEMC. National Electricity Rules, Chapter 5A - Electricity Connection for Retail Customers, Version 93. Page 651.
[190] Ibid. Page 663. "A Distribution Network Service Provider must use its best endeavours to make a negotiated connection offer to the connection applicant within 65 business days after the date of the application for connection (but the time taken by the applicant to provide information reasonably sought by the Distribution Network Service Provider under clause 5A.C.3(a)(2) will not be counted)."
[191] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[192] GSES. How to Use Chapters 5 and 5A from NER for Large Scale Embedded Generators. 2 March 2022.
[193] AEMO. Technical Requirements for 200 kW to 5 MW DER Connections. 2024. Page 30.
[194] SA Power Networks. NICC270 Connection of Medium and Large Embedded Generation Greater Than 30KVA. 2025. Page 18.
[195] United Energy. Embedded Generation Fees and Charges. October 2024.
[196] IEEFA Interviews. Also see: SA Power Networks. NICC270 Connection of Medium and Large Embedded Generation Greater Than 30KVA. 2025. Page 19. "Please note that the above indicative costs may vary (or may incur variations) for any of the stages above if: • your proposal is complex in nature; • require additional efforts by SA Power Networks (e.g. studies, analyses, modelling, investigations and/or level of services)"

3 to 18 months for the distribution business to provide the additional capacity needed for the facility. This can be due to: Lead times for critical parts necessary for the augmentation, and; Scheduling augmentation works in the DNSP capital works program."[197]

- **Under-resourcing of DNSPs:** IEEFA interviewees reported that some DNSP connections teams may not have the capacity to deal with the increasing connection application pipeline.[198] This was also identified by Oakley Greenwood: "Some proponents believed that some DNSPs appear to be under-resourced in terms of both the number and level of experience of the personnel involved in the connection process, particularly in the context of the large ramp up in connection applications for EVSE [electric vehicle supply equipment] and large CER and potentially grid-side batteries."[199]

It is evident the grid connection process for C&I solar and storage is **inconsistent, slow and, in some circumstances, unpredictable,** acting as a material barrier to investment at a larger scale. While the process is governed nationally under NER Chapter 5A, DNSPs have discretion over specific technical requirements, meaning proponents face materially different standards depending on which network they connect to. Additional technical requirements can emerge during the process rather than being stated upfront, creating iterative loops of revision and additional study that compound delays and cost. This sits on top of process burdens, including extensive network modelling requirements and a lack of network visibility for project proponents. Grid connection costs can also vary significantly across DNSPs.

C&I projects are structurally exposed to these pressures. They can face quite a complex negotiated connection process but do not usually have the commercial scale to efficiently absorb delays, increased development costs or financing uncertainty. The time cost of delays compounds these pressures – both through the cost of capital during an extended approval period and forgone energy cost savings while a viable system awaits connection. Projects that are technically and commercially viable can face months of approval delays and unpredictable cost blowouts, undermining investment confidence and slowing deployment. Grid connection emerges as a commercial risk that hinders the fast deployment of C&I solar and storage projects.[200]

Recommendation 3: Streamline the grid connection process

To accelerate C&I solar and storage uptake, the grid connection process should be streamlined. We provide recommendations for consideration below:

[197] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 2.
[198] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[199] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 26.
[200] Illumine-i. Grid Approvals: The Silent ROI Killer in Australian C&I Solar - And How to Fix It. 29 October 2025.

a) A fast-track connection pathway should be developed (similar to residential systems) for C&I projects that adhere to a standard technical architecture that mitigates power quality and safety risks. This should be developed by the National CER Technical Regulator with input from DNSPs and the C&I sector.

In the 2000s, small residential solar systems faced a similar, highly involved process for network connection that now applies to solar systems above 200kW. This even included requiring additional network protection equipment to be installed. However, DNSPs came to realise that such systems – if they used technology that adhered to Australian and international standards and with some size restrictions – posed minimal risks to power quality and safety. This meant DNSPs could very quickly and easily approve the connection of thousands of systems to the grid without needing to check the specific network circumstances applying to each system. Also, with the introduction of technology that allows DNSPs to remotely curtail system output (known as Dynamic Operating Envelopes [DOEs]), restrictions on the size of exports from residential systems have been considerably relaxed in some areas.

While C&I systems can be far larger than residential systems in absolute terms, their scale relative to the load they serve and the network capacity they are connected to is often not that different to residential systems. A number of technical experts we interviewed believe the risks addressed by lengthy grid connection processes and studies for C&I systems could instead be mitigated by defining a set of technical characteristics or architecture that C&I systems need to meet in order to get a fast-tracked connection – similar to how the vast bulk of residential systems are currently handled.[201] In particular, the advent of DOEs means DNSPs now have the capability to adjust the output of DER systems to ensure they stay within limits that minimise risks to power quality and safety.

The Clean Energy Regulator's incoming National Technical Regulator for Consumer Energy Resources should, as an immediate priority, convene a working group to define a standard technical architecture for large BTM solar and battery projects, which could be approved under a fast-track connection pathway. This working group should include C&I project proponents, DNSPs, power engineering experts and technology vendors. A more involved and longer connection application process could still be retained for projects that fall outside the standard architecture. How this could work is – for example – a project first obtains a fast-track connection if it adheres to standard technical architecture, and then subsequently if it opts to, it could go through the more detailed, lengthy process which might ultimately allow the system design to be designed in a more bespoke manner.

[201] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026

It is important that any streamlined process and corresponding standard technical architecture is adopted consistently by all main grid DNSPs. It should be noted that the CCA also recommended that governments "require DNSPs to standardise application processes".[202]

Box 2: US accelerated C&I grid connection processes – California's Rule 21

California's Rule 21 provides a fast-track grid connection process for qualifying solar and storage systems configured to not export to the grid. Because no energy is sent to the grid, the process usually bypasses extensive study and is approved quickly.[203]

"Rule 21 also contains provisions for inadvertent export systems and limited-export systems with inadvertent exports. The rules specify what types of export control technologies are necessary to comply with the requirements."[204]

The incorporation of Integration Capacity Analysis tools allows developers to identify low-constraint sites upfront using publicly accessible maps, further streamlining approval for qualifying projects.

Other US states that offer accelerated connection for non-export systems include Arizona, Colorado, Hawaii, Illinois, Maryland, Minnesota and Nevada.

b) Technical requirements should be harmonised across Australia (or at least NEM-wide) with the Clean Energy Regulator's National Technical Regulator for Consumer Energy Resources playing a key role.

Equipment manufacturers and developers of sub-5MW DER in the NEM told AEMO that: "DNSPs varied, and differing requirements for connections makes it difficult to standardise offerings and adds greater cost than would otherwise be necessary under a scenario where a NEM-wide standard was applicable and enforced. Some developers called for existing requirements to be 'harmonised' across the NEM."[205] AEMO has noted the benefits of harmonising technical requirements across DNSPs.[206]

AEMO published a final consultation report on technical requirements for sub-5MW DER connections in September 2024, identifying gaps in the regulatory framework and recommending technical

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[202] CCA. Unlocking Australia's Clean Energy Potential. June 2025. Page 39.
[203] Energy Toolbase. Fast Track Interconnection Process for Commercial Solar Projects is Streamlined with the Incorporation of Integration Capacity Analysis (ICA) Tools within California's Rule 21. 5 October 2022.
[204] NC Clean Energy. Interconnecting Non-Exporting Systems: How do States and Utilities Interconnect DG Customers that Don't Export Electricity? 27 September 2024.
[205] AEMO. Technical Requirements for 200 kW to 5 MW DER Connections. September 2024. Page 30. "DNSPs varied, and differing requirements for connections makes it difficult to standardise offerings and adds greater cost than would otherwise be necessary under a scenario where a NEM-wide standard was applicable and enforced. Some developers called for existing requirements to be "harmonised" across the NEM."
[206] AEMO. Technical Requirements for sub 5 MW DER Connections. November 2025. Page 12.

performance standards for systems in the 200kW–5MW range.[207] The report was subsequently developed into a guideline, published in November 2025, which AEMO considers an "interim measure prior to the development of a national standard covering connections in this sub 5 MW DER category".[208] The guideline is informing work with the Standards Australia EL-064 committee, with AEMO stating, "AEMO will work closely with Standards Australia EL-064 committee towards the development of a suitable Australian standard for DER connections considered in the review."[209]

In IEEFA's view, to speed up C&I solar and storage connections and reduce costs, it is pivotal that technical connection requirements are harmonised across Australia (or at least the NEM) and that all DNSPs adhere to these requirements as soon as possible. The new National Technical Regulator for Consumer Energy Resources has a key role to play in this, as do other energy market institutions and agencies, such as AEMO.

It should be noted that the existing AEMO review covered 200kW–5MW systems; however the National Technical Regulator for Consumer Energy Resources and other institutions should also consider whether technical requirements for systems smaller than 200kW also need to be harmonised.

c) DNSPs should be required to publish granular data on DER hosting capacity by location via a national, publicly accessible online portal.

This would help proponents identify viable sites before beginning the formal connection process. Network capacity data is not widely available in a low transaction-cost manner for large CER and EVSE, as usually "proponents seeking network capacity information to confirm whether a particular site might be economically developed must approach a DNSP".[210] Some DNSPs, such as Energex, Essential and Ausgrid, provide significant information through online network maps.[211,212,213] However, other networks do not – and there is no requirement for DNSPs to publish standardised or granular, feeder-level hosting capacity maps.[214] The AEMC is considering a rule change to formulate a new distribution network planning process and a principles-based framework for distribution network data reporting.[215] Ideally, this would enable the publication of harmonised, publicly available data on feeder-level network CER hosting capacity and other relevant network data. DNSPs should be required to provide this information through a single, publicly accessible online portal, in a harmonised manner so that the same level of information is available across all DNSPs. This would

[207] AEMO. Technical Requirements for 200 kW to 5 MW DER Connections. September 2024. Page 4.
[208] AEMO. Technical Requirements for sub 5 MW DER Connections. November 2025. Page 6.
[209] Ibid. Page 7.
[210] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 29.
[211] Energex. Network Load Capacity Map. Accessed 13 May 2026.
[212] Essential Energy. Overhead Network Maps. Accessed 13 May 2026.
[213] Ausgrid. Distribution and Transmission Annual Planning Report Summary. December 2025. "We are also enhancing the visibility of the network by expanding our mapping portal in early 2026 to incorporate 11kV and low voltage network assets, giving customers, councils and developers clearer insights into network hosting capacity and opportunities for connection."
[214] AEMC. National Electricity Rules, Schedule 5.8 – Distribution Annual Planning Report.
[215] AEMC. Enhancing Distribution Network Planning and Reporting, Draft Rule Determination. 23 April 2026. Page i.

better enable C&I project site selection, and reduce wasted effort and cost for proponents and DNSPs at the site selection stage.

d) DNSPs should be required to publish data on C&I grid connection application processing timeframes, and this should be collated and compared as part of broader network reporting processes.

There is no standardised reporting on grid connection performance across DNSPs. Data on connection timeframes, success rates, costs and reasons for abandonment is not collected or published, making it impossible to compare DNSP performance or identify best practice. Requiring DNSPs to report this information would improve transparency and give proponents better visibility of expected timeframes. This recommendation was also outlined in the Oakley Greenwood study for DCCEEW.[216] The AER could be responsible for collating the data and comparing performance across DNSPs as part of existing reporting processes, such as the network performance report. In the utility-scale space, AEMO publishes a Connections Scorecard (for utility-scale projects falling under Chapter 5 of the NER); however no equivalent connections data is available for the C&I sector.[217]

e) DNSPs should be incentivised to process grid connection applications quickly.

According to the Oakley Greenwood study, "Project proponents and local council stakeholders also noted that where DNSPs employ specialised connections staff and staff dedicated to the connection of these new project types, the connection process has been significantly quicker and less problematic."[218] DNSPs could invest in digital tools to automate routine assessment steps, and build up connections capability within DNSP teams. Incentivising DNSPs to streamline grid connection processes could deliver further efficiencies.

Oakley Greenwood found economic benefits of AU$180 million (net present value) are available from improving information on available network capacity at specific locations and enabling faster connection, energisation and network augmentation (where required) across large CER and EVSE.[219]

Uneven playing field for DER-provided network services

C&I solar and storage assets – and DER more broadly – have the potential to provide network services. The regulatory system assumes DNSPs are the monopoly providers of network services,

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[216] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 3. "Baseline information is needed about the length of time the connection process (and possibly each step within it) currently takes, by type of project, including how much time is required by the DNSP and the project proponent. This information is not currently available and DNSPs should be required (by a regulation) to collect and publish this information."
[217] AEMO. Connections Scorecard. March 2026.
[218] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 26.
[219] Oakley Greenwood for DCCEEW. Streamlining the Connection of EVSE and large Consumer Energy Resources: Options Paper for Consultation. 26 August 2024. Page 2.

yet DER owned by households and businesses can increasingly provide network services, such as congestion management, voltage control, reliability enhancement and network deferral.[220] Baringa estimated that DER integration could deliver AU$11 billion in distribution and transmission avoided costs and benefits by 2040.[221] However, the NEM is lacking comprehensive mechanisms to procure network services from C&I solar and storage assets (or DER more broadly), and the economic regulation does not create incentives for DER-provided network services to be valued on a level playing field with capital investment in poles and wires.[222]

The RIT-D process, in principle, should assess DER as an alternative to networks. When DNSPs plan investments above the AU$7 million cost threshold, they must identify and assess all credible options that could serve the identified network need, explicitly including non-network alternatives such as local generation, demand management and energy storage, and select the option that maximises net economic benefit.[223] The consultation process for alternative options is open to registered participants, AEMO, non-network providers and interested parties, meaning C&I solar and storage providers can, in theory, submit non-network solutions for consideration.[224]

In practice, however, the RIT-D process itself has a number of issues preventing effective competition from non-network alternatives in the form of C&I solar and storage.

Firstly, the RIT-D process runs on a timeframe that is not conducive for C&I investment decision-making. The mandatory consultation period for the Options Screening Report is a minimum of three months, in which time proponents can submit non-network options.[225] After this, a draft report must follow within a year (with a six-week minimum consultation window) then a final report.[226] A C&I project cannot be held in development stasis while waiting for these processes to conclude – capital commitments must be made on the business customer's timeline, not the network's.

Secondly, DNSPs can bypass the full formal options screening report. The guidelines permit a DNSP to skip the Options Screening Report if it determines "on reasonable grounds, that there will not be a non-network option or a SAPS [stand-alone power system] option that is a potential credible option".[227] The DNSP publishes its reasons after the fact, leaving stakeholders to challenge the decision through a dispute process if they choose to.

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220 IEEFA. Reforming the Economic Regulation of Australian Electricity Distribution Networks. May 2024. Page 4.
221 Baringa Partners. Potential network benefits from more efficient DER integration. 18 June 2021.
222 IEEFA. Reforming the Economic Regulation of Australian Electricity Distribution Networks. May 2024. Page 4.
223 AER. Regulatory Investment Test. Accessed May 2026. The $7 million threshold is confirmed in: AER. 2024 Cost Thresholds Review for the Regulatory Investment Test - Final Determination. 12 November 2024.
224 AER. Regulatory Investment Test for Distribution - Application Guidelines. November 2024. Page 61.
225 AER. Regulatory Investment Test. Accessed May 2026.
226 AER. Regulatory Investment Test for Distribution - Application Guidelines. November 2024. Pages 60 and 65.
227 Ibid. Page 63: "All RIT-D proponents must prepare and publish an options screening report unless they determined, on reasonable grounds, that there will not be a non-network option or a SAPS option that is a potential credible option or that forms a significant part of a potential credible option."

Thirdly, an information provision burden also exists. Stakeholders must “provide sufficient information to enable the RIT-D proponent to assess the option’s technical feasibility” – which involves significant work and cost with no guarantee of selection.[228]

Fourthly, the information asymmetry between DNSPs and potential non-network solution providers remains significant. DNSPs are the gatekeepers of network constraint data, and while there are requirements to publish certain network information in the Distribution Annual Planning Report, Energy Networks Australia (ENA) has acknowledged that it is “outdated and difficult to understand”.[229] The AER updated the RIT-D guidelines in November 2024, and the AEMC’s April 2026 draft determination on distribution planning could improve data availability.[230,231] However, the AEMC’s proposed enhanced distribution planning updates are not yet in effect, and it remains to be seen whether they will deliver the accessible, detailed, proponent-facing network data needed to level the playing field. Without accessible, granular network constraint data published ahead of a formal RIT-D process, non-network proponents are hindered in identifying opportunities early enough to develop solutions to the required level of specificity, and they are hindered in effectively challenging a DNSP’s determination that no credible non-network option exists. Poor data quality and timing can therefore compound each of the issues mentioned above.

These process issues make it difficult for C&I generation and storage projects to compete effectively with network solutions. Energeia’s research found that less than 10% of RIT-D projects from 2016 to 2018 implemented a non-network alternative.[232] IEEFA interviewees reported that RIT-D revenue could not be used to underwrite a C&I investment; it could only be treated as upside in a financial model.[233] The RIT-D, despite being designed to allow non-network alternatives to compete, provides little practical investment support for C&I solar and storage. More fundamentally, the options screening process in the RIT-D frames non-network solutions as an alternative option for DNSPs to procure, rather than placing non-network solutions in full competition with traditional network options.

To achieve efficient investment levels in all asset types, ideally the economic regulation regime would consider non-network solutions on a level playing field with traditional poles and wires investment.[234] Network incentives do not appear to enable this: Energeia found that “spending on capital works such as grid upgrades increase shareholder returns by 200 percent compared to the best performing non-network incentive.”[235] Further, several reports and reviews have suggested that an

[228] AER. Regulatory Investment Test for Distribution - Application Guidelines. November 2024. Page 64: “RIT-D proponents should request stakeholders to support any potential credible options they propose and provide sufficient information to enable the RIT-D proponent to assess the option's technical feasibility.”
[229] Energy Networks Australia (ENA). Submission - Integrated Distribution System Planning Directions Paper. July 2025. Page 2.
[230] AER. 2024 Review of the Cost Benefit Analysis and Regulatory Investment Test Guidelines. November 2024.
[231] AEMC. AEMC Proposes Enhanced Distribution Network Planning to Support Local Energy Solutions. 23 April 2026. AEMC Chair Anna Collyer: “With detailed visibility of where solar, batteries and EVs are emerging, DNSPs and investors can plan ahead through targeted upgrades or non-network solutions.”
[232] Energeia. Renew DER Optimisation (Stage II): Final Report. September 2021. Page 2.
[233] IEEFA interviews with C&I solar and storage stakeholders. 2025 and 2026.
[234] IEEFA. Reforming the Economic Regulation of Australian Electricity Distribution Networks. May 2024. Page 25.
[235] Energeia. Are electricity network incentive schemes rewarding the wrong behaviour?. 3 May 2022.

outcome of the economic regulation regime, and how it is administered, is a bias towards capital investment and growth of the Regulated Asset Base.[236]

Box 3: Great Britain Flexibility Markets example

Great Britain offers a compelling example of what is possible when a regulatory framework is designed to enable DER-provided network services. Approximately 20% of network areas in Great Britain are constrained, and each of the six distribution networks actively procures flexibility services from DER owners, including C&I solar, storage and demand response assets, to manage those constraints rather than focusing solely on investing in network augmentation.

DER owners can earn up to GBP33/kW (AU$62) a year in constrained locations – for example, a 10kW home battery can earn up to GBP331 (AU$621) a year.

By August 2023, 2.4GW of flexibility services had been contracted across Great Britain for FY2023-24.

Source: IEEFA.[237]

Recommendation 4: Review the economic regulation of distribution networks

Australia should undertake an independently led, first-principles review of the economic regulation of distribution networks. This should examine the potential for non-network solutions such as DER to compete with traditional poles-and-wires investment.

Internationally, momentum is growing towards reform of the economic regulation of electricity networks, with jurisdictions such as the UK introducing payments for DER to provide network services. Australia has conducted successful trials demonstrating that DER can provide network services – including Projects Networks Renewed, CONSORT, Edge, Edith and Symphony – but has not yet developed a systematic framework to procure these services at scale.[238]

A first-principles review of distribution network economic regulation should be undertaken to ensure efficient investment across all asset types – including both traditional poles and wires and DER-

[236] IEEFA. Reforming the Economic Regulation of Australian Electricity Distribution Networks. May 2024. Page 26.
[237] Ibid. Page 42.
[238] Ibid. Page 8.

provided network services. As the core issue concerning distribution network economic regulation is whether networks are still a monopoly service or whether they are contestable, the potential for non-network solutions to compete with traditional poles-and-wires investment should be examined in the review. The review could consider reforms that would allow non-network solution providers to participate in network service delivery independently of the DNSPs whose capital investment they would defer or replace. More broadly, the review should examine how to ensure efficient costs of network services for consumers.

Conclusion

The barriers to C&I solar and storage deployment in Australia are multifaceted, including business-level investment barriers; complex, inconsistent network tariffs; inconsistent, slow and unpredictable grid connection processes; and an uneven playing field for DER-provided network services. There has historically not been as much focus on overcoming the barriers to C&I solar and storage uptake as the residential or utility-scale renewables and storage sectors. Left unaddressed, these barriers will continue to constrain investment, slow down uptake, and leave the full potential of C&I solar and storage unrealised.

The recommendations in this report offer a coherent agenda for unlocking the C&I sector's contribution to Australia's clean energy transition: appropriate incentives; standardised and reviewed network tariffs; streamlined grid connection processes; and a reformed network economic regulation framework. Implementing these recommendations could unlock the C&I sector at scale and speed, help serve electricity demand and accelerate decarbonisation.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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Johanna Bowyer is the Lead Analyst for Australian Electricity at IEEFA. Her research is focused on trends in the National Electricity Market, energy policy and decarbonisation. Prior to joining IEEFA, Johanna researched distribution networks at CSIRO, worked in solar energy businesses and worked as a management consultant at Kearney. Johanna has a first-class Honours Degree in Photovoltaics and Solar Energy Engineering from UNSW Australia. While at UNSW she received the Co-op Scholarship, No Carbon Women in Solar Prize and Photovoltaics Thesis Prize.

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