UNLOCKING THE MISSING MIDDLE

Commercial and Industrial Distributed Energy Resources in Australia

A Report by the Smart Energy Council

JULY 2026

SMART ENERGY COUNCIL

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A Triangulated Evidence Report: Literature Review, Member Survey and Stakeholder Interviews

SMART ENERGY COUNCIL

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1. Executive Summary

1.1 Context

Commercial and industrial (C&I) facilities consisting of manufacturing, logistics, retail, agriculture, data centres and the public sector all sit on a large, underused energy asset base. These sites combine high daytime loads, large roof areas and the financial capacity to invest, yet deployment of C&I solar, battery storage and flexible load management remains well below its technical and economic potential.

This report focuses on the 100 kilowatt to 30 megawatt segment, often described as the missing middle: too large for residential incentive schemes, too small to access the policy and market mechanisms built for utility-scale generation.

The Smart Energy Council undertook this study to identify the barriers suppressing C&I distributed energy resource (DER) deployment and to propose reforms that could unlock it. The findings draw on three independent evidence streams:

- a literature review of more than 80 sources
- a member survey of 61 respondents drawn from technology providers, installers, developers, financiers, network participants and consultants
- in-depth interviews with ten industry practitioners spanning measurement and verification, landlord and tenant representatives, community energy, large-scale solar and battery development, and C&I solar installation

1.2 Key Findings

- The underlying economics of C&I solar and storage are strengthening, but value is increasingly tied to flexibility and demand management rather than energy arbitrage alone.
- Connection processes and network constraints, not technology are the dominant barrier to deployment. 71% of survey respondents cited the length of DNSP approval times as a leading connection challenge, and 82% identified connection requirements as the area where governance is least consistent.
- Tariff structures, particularly demand charges, are the single largest influence on system sizing decisions, cited by 63% of survey respondents, yet only 2% of respondents believe current tariffs support C&I investment in flexibility and storage very well.
- Landlord and tenant misalignment is one of the most persistent and least resolved barriers in the sector. It is acknowledged in the literature but under-analysed; industry interviews provide the strongest evidence that split incentives, short lease terms and unclear asset ownership are suppressing investment across multi-tenant commercial property.
- The collapse in Large-scale Generation Certificate (LGC) prices to roughly $3 to $4, down from $20 to $30 in past years, has materially reduced project viability and closure rates across the sector. One interviewee reported quote-to-contract conversion falling from eight in ten, to one in ten.
- Data access and interoperability remain foundational constraints. 81% of survey respondents rate interoperability issues as significant, and 61% rate access to hosting capacity and real-time network data as poor or limited.

1.3 Strategic Recommendations

Section 4 sets out the report's recommendations in detail. They centre on five priorities: standardising and accelerating DNSP connection processes with enforceable timeframes; reforming network tariffs toward cost-reflective, flexibility-rewarding structures; restoring a credible price signal in the Large-scale Renewable Energy Target or an equivalent mechanism; establishing a standardised commercial green lease framework to resolve landlord-tenant misalignment; and mandating national data access and interoperability standards for C&I-scale distributed energy resources.

No single reform is sufficient on its own. Connection reform, tariff reform and a stable certificate price together determine whether a C&I project proceeds, while landlord-tenant reform determines whether a large share of the addressable market including multi-tenant commercial property can participate at all.

Recommended Advocacy Priorities

Timeframe	Reform	Rationale from Survey + Evidence
Immediate	Connection process standardisation	70% of survey respondents cite this as a top advocacy priority; 70.9% report slow DNSP approvals as a key connection challenge
Immediate	SRES threshold reform to 500kw-1 MW	71% cite high upfront capital costs; 50% say SRES variation would significantly improve the business case. Industry consultation on the expansion to 500kw or 1MW should be considered to avoid a possible quality gap occurring.
Short-term	Accelerated depreciation for solar and battery assets	Reduces capital cost burden; supports the owner-occupier segment; administratively straightforward
Short-term	LGC floor price or mid-scale support mechanism	75% of respondents say an LGC price above $25/MWh is needed, or are unsure; current prices are inadequate
Short-term	Green lease and split-incentive frameworks	39.4% say split incentives create barriers 'often' or 'almost always'; 73.5% cite capital investment responsibility as the key misalignment
Short-term	Mandatory network data transparency	54.5% cite real-time network data gaps; 54.5% cite hosting capacity information gaps as major issues

2. Introduction and Methodology

2.1 The Missing Middle: A Structural Policy Gap

Australia's energy transition is entering its decisive decade. The national target of 82 per cent renewable electricity by 2030, combined with accelerating electrification across industry, transport and the built environment, is reshaping the National Electricity Market. Yet the commercial and industrial sector remains structurally underserved by policy, underrepresented in deployment, and underexamined in national planning.

The C&I sector sits between two well-supported ends of the market. At one end, the Small-scale Renewable Energy Scheme (SRES) has driven more than three million residential solar installations through clear rules, simple processes and strong consumer incentives. At the other, the Large-scale Renewable Energy Target (LRET), the Capacity Investment Scheme and state procurement programs have underpinned the growth of utility-scale solar, wind and storage. Between these two poles sits a large, economically significant segment; the missing middle, comprising systems from 100 kW to 30 MW deployed across factories, warehouses, logistics hubs, cold stores, retail centres, farms, data centres and commercial precincts.

This report examines why this segment has not scaled in line with its potential, despite strong underlying economics, rapidly improving technology and growing corporate interest in electrification, resilience and emissions reduction. It presents the most comprehensive Smart Energy Council knowledge to date of the structural, regulatory, commercial and institutional barriers facing C&I solar, storage and flexible demand in Australia, and proposes a coherent national reform blueprint to unlock this opportunity.

Despite its importance, the C&I sector has never had a coherent policy framework. SRES was designed for small-scale systems and caps out at 100 kW. The LRET was designed for utility-scale generation and is now nearing its end, with certificate prices collapsing to $3-$4/MWh. State programs have tended to focus on residential batteries, community energy or large-scale procurement, leaving mid-scale commercial and industrial projects without a clear pathway. Interviewees described this structural void with striking consistency:

> *"That sector has just never had a shot … there's never been any supportive policy to unlock it."*
> **C&I Installer**

> *"The LGC crash has decimated business cases. Hundreds of megawatts are paused waiting for a price signal."* **C&I Project Manager**

> *"We need a successor to the LRET or a bespoke mid-scale mechanism … the current settings don't work."*
> **Medium Scale Installer**

2.2 Purpose

This report brings together three independent bodies of evidence to give the Smart Energy Council, government energy departments and industry stakeholders a triangulated, evidence-based view of the barriers and opportunities for commercial and industrial distributed energy resources in Australia. The objective is to move beyond anecdote and isolated case studies toward a structured evidence base that can support specific, actionable policy reform.

2.3 Evidence Streams

2.3.1 Literature Review

A structured literature review synthesised more than 80 sources across six categories: academic literature; government and regulatory documents; market and system operator publications; industry and investor reports; demonstration and trial reports; and trade and media publications. Sources were classified by analytical strength and relevance to C&I consumer energy resources. System planning and regulatory literature provided the strongest evidence base; C&I-specific business model and governance literature was comparatively underdeveloped.

2.3.2 Member Survey

A survey of Smart Energy Council members was conducted between April and May 2026, gathering up to 61 responses depending on the question, from technology providers, installers and integrators, developers, investors and financiers, network and market participants, and consultants and advisory firms. The survey used a mix of multiple-choice, ranking and weighted-average rating questions, supplemented by open-text responses, to generate quantitative evidence on drivers, barriers, tariffs, data access, business models, resilience and the tenant-landlord dynamic.

2.3.3 Stakeholder Interviews

Ten semi-structured interviews and policy discussions were conducted with industry practitioners between April and May 2026, each approximately one hour in length. Interviewees included a measurement and verification and certificate specialist, a landlord-side energy lead from a major property group, three C&I solar and battery developers and installers operating at different scales, a community energy and midscale generation specialist, and a commercial solar consultancy. Interviews followed a consistent question framework covering investment drivers, connection processes, tariffs, data access, business models, resilience, technology standards, landlord-tenant dynamics and policy reform, while allowing interviewees to raise issues outside that framework. A draft of the final report was returned to each interviewee for review and comment, consistent with the research protocol agreed with participants.

2.4 Analytical Approach

Findings from the three evidence streams are presented thematically in Section 3. Each finding is attributed to its source: literature review sections, specific survey questions, or named interviews. Where the three streams align, this is noted explicitly; where they diverge, or where industry evidence extends beyond what the literature has examined, this is also noted. The aim is to make visible not only what the evidence shows, but how confident that evidence is and where it originates.

3. Key Findings

This section presents findings grouped by theme. Each subsection draws on all three evidence streams where available and notes points of alignment or contradiction between the literature, survey data and interview evidence.

3.1 Investment Economics and Drivers

Across every evidence stream, financial return is overwhelmingly the dominant driver of C&I investment in solar, storage and flexible loads. 94.7% of survey respondents cited cost savings as a top investment driver, far ahead of sustainability commitments (49.1%), resilience and reliability (45.6%), electrification (29.8%), grid resilience (29.8%), corporate reporting requirements (14.0%) and supply chain expectations (10.5%). This aligns directly with the literature review's finding that the economics of C&I solar and storage are strengthening, with value increasingly tied to flexibility rather than energy arbitrage alone. Interview evidence is consistent across all six practitioners:

> *"Eight times out of ten it purely boils down to money in versus money out."* **C&I Installer**

> *"ROI and bill shock are the primary drivers."* **Qld C&I Installer**

Survey Finding	Result	Note
Cost savings	94.7%	By far the dominant driver
Sustainability commitments	49.1%	Second most common
Resilience and reliability	45.6%	Third most common
Electrification	29.8%	Growing importance
Grid resilience	29.8%	Emerging system value
Corporate reporting requirements	14.0%	ESG disclosure pressure
Supply chain expectations	10.5%	Still nascent

Interview evidence adds nuance the survey cannot capture. Several interviewees said emissions reduction has become a materially weaker driver than it was three to four years ago, attributing the shift to a changed political environment that has reduced the perceived urgency of decarbonisation commitments among C&I customers. One interviewee said the closure rate on quoted C&I solar projects had fallen from roughly eight in ten to one or two in ten over the past two years, driven mainly by the collapse in certificate prices, which has stretched payback periods from around two to two-and-a-half years to closer to four years for solar alone, and around nine years once a battery is added. This contradicts an assumption in some literature that resilience and sustainability are emerging as co-equal investment drivers; both the interview and survey evidence show cost remains dominant by a wide margin, with resilience and sustainability as secondary or contingent factors.

Confidence in the business case is moderate at best. Respondents rated their confidence in the solar and storage business case at an average of 2.88 out of 4, with only 21.4% describing themselves as very confident and nearly one-third reporting uncertainty or a lack of confidence. This reflects the fragility of business cases under tariff volatility, connection delays, policy uncertainty and not weakness in the underlying economics. It is consistent with interview reports of constrained capital allocation: several interviewees described C&I customers comparing solar and storage investment directly against alternative uses of capital, such as production line upgrades, and noted that solar frequently loses that comparison once payback periods extend beyond three to four years.

The retail focused interviewee described electrification requirements, particularly government and large tenant commitments to remove gas and support electric vehicle charging, as a stronger current influence on lease negotiations than solar or storage economics on their own.

The industrial development interviewee described accelerated depreciation or asset write down treatment for onsite generation assets as a welcome addition rather than a genuine unlock, noting that existing depreciation schedules and internal tax teams already identify and capture available benefits. This point was not raised with the retail focused interviewee.

The industrial development interviewee costed utility scale battery systems at an estate wide level in the order of nine million to twelve million dollars, illustrating the capital intensity that limits broader deployment even where surplus land is well suited to a battery installation.

System Sizing and Threshold Effects

Structural connection cost thresholds create perverse incentives that systematically suppress system sizes across the sector. Systems are deliberately capped at 30 kW to avoid $9,000 to $10,000 in DNSP and engineering fees, even when customers need 40 to 50 kW systems. Similarly, the 100 kW SRES threshold drives customers to install 100 kW systems when they need 200 to 400 kW, since LGC administration costs at $3 to $4/MWh make above-threshold projects commercially unviable.

System Size	Technology	Primary Driver	Structural Constraint
15–99 kW	Solar only	Cost reduction, SRES support	None well served
100 kW–1 MW	Solar ± battery	Demand management	SRES cliff edge; LGC collapse
1–5 MW	Solar + battery	Demand, VPP, ESG	Complex DNSP; no mid-scale mechanism
5–30 MW	Solar + battery, microgrid	Off-grid, system services	Generator registration; CfD inaccessible, complex DNSP and no mid-scale mechanism.

Battery Storage Economics

Battery storage is now present in 92.9% of respondents' offerings, but economics remain fragile in urban grid-connected settings. The primary value streams realised in practice are peak demand management (74.4%) and demand charge reduction (62.8%), ahead of resilience (32.6%) and market services (32.6%). Revenue predictability is a significant concern: only 4.6% of respondents rate revenue streams as highly predictable, while 43.2% describe them as variable or unpredictable.

The urban versus remote contrast is stark. A 2 MW solar and 7 MWh battery system at an urban industrial site (15 cents/kWh tariff) delivers only 8% savings; approximately $150,000 per year. The same system in a remote location, replacing diesel at 45 to 60 cents/kWh, produces a compelling business case. Battery economics are strongest where grid electricity is expensive or unreliable which is a dynamic with direct implications for where policy support is most needed.

3.2 Connection Processes and Network Barriers

Connection processes are the most consistently cited barrier across all three evidence streams, and the area of strongest alignment between literature, survey and interview evidence. The literature review identifies lengthy applications, uncertainty about export limits and hosting capacity, inconsistent technical requirements and high engineering costs as the dominant problems, concluding that connection remains a major barrier for most C&I projects despite initiatives such as AEMO's connection scorecard.

Survey respondents rated the ease of navigating C&I connection processes at an average of 6.8 out of 10 and identified length of approval times as the most common connection challenge at 71%, ahead of slow response times (67%) and lack of transparency (40%). 85% of respondents reported that connection issues sometimes or frequently change system design or commercial outcomes materially. Governance inconsistency around connection requirements was the most widely cited governance gap in the survey, at 82%.

Survey Finding	Result	Note
Length of approval times	70.9%	Most common challenge
Slow response times	67.3%	Second most common
Changing technical requirements	50.9%	Fourth most common
Export limits	36.4%	Also significant
Lack of transparency	40.0%	Third most common
Hosting capacity uncertainty	30.9%	Fifth most common

Interview evidence corroborates and sharpens this picture with specific, documented cases. One interviewee described an assurance from a Victorian DNSP to its energy efficiency regulator that approval for a 200 kW solar system would take five to ten business days and yet the same interviewee had personally observed compliant, payment-ready projects stalled for five months awaiting that approval.. A community energy and midscale generator reported that its original grid connection cost estimate of $250,000 ultimately reached $1.6 million once feeder upgrade works were complete, and that a distributed energy resource management system requirement only became apparent in the final weeks of a generator performance standards approval process which is a cost that could kill a comparable project without the right financial buffer. A third interviewee, operating across multiple states, described routinely sizing and selling systems before applying for grid connection, because the engineering studies required to apply cost between $2,500 and $10,000.   Meaning connection risk is discovered only after a financial commitment has already been made to the customer.

The industrial development interviewee linked this inconsistency directly to weaker investor confidence, since developers cannot rely on a predictable approval pathway when planning capital deployment across a multi-state portfolio. The retail infrastructure focused interviewee separately supported the idea of an early, lightweight feasibility check with the network operator before a full connection application is lodged, so that a project's viability can be tested quickly rather than discovered only after significant design and consultant cost has been incurred.

Local councils were described as reluctant to approve cabling running beneath roads to connect embedded network infrastructure across a site, even where this would allow more efficient use of otherwise underused land within very large industrial estates.

A possible reform raised was a nationally consistent depth-based standard, for example treating cabling buried beyond a set depth beneath a road as generally acceptable, to remove this as a case by case planning obstacle.

Industry evidence extends the literature in one specific respect: several interviewees independently proposed that distribution networks should be required to publish fast, low-cost indicative connection outcomes which would be effectively a quoting tool before a customer commits capital. This is not prominent in the literature review's recommendations but is consistent with its broader call for hosting capacity transparency.

> *“Some approvals take five months instead of 5–10 business days.”* **M&V Consultant**

> *“It's all incredibly opaque and not replicable.”* **C&I Installer**

> *“Connection approval times of 6-plus weeks are the most significant challenge.”* **C&I Project Manager**

3.3 Tariffs and Network Access

The literature review identifies demand charges as the dominant tariff element influencing system sizing . This is a finding the survey confirms directly: 63% of respondents identified demand charges as the tariff element most influencing system sizing, ahead of peak pricing (52%) and time-of-use rates (50%). Yet only 2% of survey respondents believe current tariffs support C&I investment in flexibility and storage very well, with 59% rating support as poor. Respondents identified clearer long-term tariff pathways as the most valued reform (54%), ahead of more cost-reflective pricing and dynamic tariffs (both 44%).

Interview evidence identifies a specific mechanism behind this dissatisfaction that the survey data alone does not surface: the mismatch between annual or infrequent tariff resets and the operational reality of behind-the-meter batteries. One landlord-side interviewee explained that current battery commercial offers ask customers to trade a firm increase in one cost for a non-firm decrease in another, because demand tariffs are typically structured around annual peak periods, a single missed period of battery availability can return the customer to their full original cost exposure with no compensating benefit, an arrangement the interviewee called untenable for any customer unable to actively manage energy market risk. A separate interviewee reported that off-peak electricity rates are now frequently higher than peak rates across many C&I bills nationally, this is a structural shift that is reducing the daytime savings case for solar specifically and may redirect future investment toward storage timed to the evening and overnight period.

The industrial development interviewee described a real stigma around exporting to the grid, where the prevailing view among owners, tenants and their consultants is that there is no point generating more than can be consumed onsite because exported energy currently attracts little or no value.

Because of this, system sizing decisions are generally made to match onsite load only, rather than to maximise available roof space. The same interviewee estimated that fully equipping a large industrial roof adds only a small fraction to overall construction cost compared with a partial system, yet commercial logic still favours the smaller, load matched system because there is no return on the additional export capacity.

The retail focused interviewee's contribution to this theme was somewhat different in substance, centring on falling wholesale energy trading revenue and uncertainty over whether trading ambitions can be realised, which is prompting a more cautious approach to expanding beyond solar only generation. This interviewee also agreed with an observation about large roofs being fitted with only a fraction of their potential solar capacity.

Together these reinforce the case, raised earlier in the research, for a more symmetrical approach to tariff design, so that the price received for exported energy is closer to the price paid to import it, giving owners and investors a clearer incentive to build to full roof capacity.

Interview evidence also identified a counter-example to the survey's general dissatisfaction: one interviewee subscribes to a commercial tariff-modelling platform that allows accurate return-on-investment modelling regardless of tariff complexity, suggesting that for sophisticated operators, tooling rather than tariff simplification may be the more immediate solution; even as simplification remains the preferred structural fix for the broader market.

> *"You slip for five minutes and you're back to paying your full operating cost again."* **C&I Installer**

> *"Off-peak rates are becoming more expensive than peak rates across many C&I bills."* **C&I Project Manager**

3.4 Data, Interoperability and Governance

Data access is identified across all three evidence streams as a foundational, cross-cutting constraint. The literature review describes improved data access as the single enabler that unlocks the greatest number of downstream benefits, including virtual power plant participation, dynamic operating envelope optimisation and financing. Survey respondents rated access to data needed for C&I system design and optimisation at an average of 2.2 out of 4, with 61% describing access as poor or limited and none describing it as excellent. The most commonly cited data gaps were real-time network data and hosting capacity information, each cited by 55% of respondents. 81% of respondents rated interoperability issues between equipment, platforms and networks as moderately or very significant, a figure the literature review also cites directly.

Finding	Survey	Note
Cite real-time network data gaps	54.6%	Q14
Cite hosting capacity information gaps	54.6%	Q14
Cite historical load data gaps	47.7%	Q14
Rate interoperability issues as significant	81.4%	Q15 : 0% say not an issue

Interview evidence presents a more differentiated picture than the survey's aggregate dissatisfaction suggests. Retailer-supplied interval consumption data was consistently described as reasonably accessible with one specialist noting that retailers generally respond to data requests within a reasonable timeframe once a signed letter of authority is in place, though data formats vary by retailer and require dedicated tooling to reconcile. The more acute gap is network-side data: hosting capacity, feeder constraint and dynamic operating envelope information, which interviewees described as opaque, expensive to obtain and, in at least one documented case, materially wrong. A community energy interviewee reported commissioning a paid feeder capacity study that found actual available capacity was double what the network had initially and conservatively advised a discrepancy only resolved because the customer was willing and able to pay for independent modelling. One interviewee also raised a previously undocumented concern: requesting interval data from a retailer can trigger unsolicited solar sales contact from that retailer's own solar arm, discouraging some customers from requesting the data needed to build their own business case.

Property owners typically have visibility only as far as their own main switchboard and site substation. Beyond that point, network capacity and congestion information is effectively unknown until a formal application is lodged with the network operator.

C&I Infrastructure interviewees said they would value access to network hotspot or capacity data early in project planning, so that sites could be prioritised or reconfigured before significant design work is undertaken, rather than relying on a consultant's judgement based on limited information.

Further, that a landholder or developer recognised as a trusted or certified participant could be given access to more detailed live network data to support site and system sizing decisions.

The industrial development interviewee separately raised an example of a distribution network operator proactively partnering with a developer in a similar situation but observed this appears to be the exception rather than a structured or repeatable program, despite their own organisation holding a very large industrial landholding that would be a natural candidate for this kind of partnership.

A second gap, identified consistently in interviews but not prominent in the survey instrument, is the absence of a consolidated, public database of DNSP tariff structures. Interviewees described this as forcing every installer to independently research and reconcile network tariffs state by state and network by network, adding cost and delay to every quote. Remote-read metering is similarly not standardised nationally, and developers routinely rebuild tools to accommodate inconsistent data formats across networks and retailers. These gaps increase engineering overhead, drive suboptimal system sizing, prevent effective battery optimisation, limit market participation and all without any technological justification.

3.5 Business Models and Financing

Direct ownership remains the most common C&I business model, cited by 74% of survey respondents, with power purchase agreements (PPAs) close behind at 54%. The literature review and interview evidence diverge meaningfully on the trajectory of PPAs. The literature describes PPAs as providing price certainty and supporting access to renewable energy without capital outlay but confirms they have broadly failed as a scalable model in the property sector, due to a structural mismatch between typical 15-to-20-year PPA terms and three to seven year commercial lease terms. Interview evidence is unanimous on this point and adds the landlord perspective the literature lacks: one landlord-side interviewee said plainly that PPAs have largely failed because most tenants do not occupy a facility for the duration a PPA requires, while an independent C&I installer raised a structural affordability concern, arguing that PPA customers typically pay more for a system over its life than they would through direct ownership or lease finance, and that businesses entering PPAs are often doing so from a weaker financial position rather than a position of choice.

Financing barriers identified in the survey are dominated by revenue uncertainty, cited by 78% of respondents, ahead of risk allocation (63%) and lack of standardised contracts (35%). Financier sentiment toward C&I battery projects is mixed: only 22% of respondents describe financiers as very willing to support such projects, against 40% describing financiers as cautious. Interview evidence identifies a specific structural cause the survey cannot: one landlord-side interviewee described current behind-the-meter procurement models as requiring 100% of an asset's productive capacity to be committed for its entire operating life to secure financing which is a risk-averse structure contrasted unfavourably with utility-scale renewable financing, where no comparable full-life, full-capacity commitment is required. The interviewee argued the mismatch reflects an avoidable market practice rather than a necessary feature of behind-the-meter risk.

For retail assets, a common and increasingly proven approach is to fund the system through the fund's own capital, generate income from tenant electricity sales, and have valuers recognise and capitalise that income into the property valuation, which then supports the investment case to fund managers.

For larger or higher risk industrial and trading scale opportunities, infrastructure interviewees pointed to a preference for outsourcing the trading function to a specialist third party operator, in exchange for passive rental income from leasing roof or land space. This avoids internal governance and taxation complications that arise when trading revenue is not linked to rental income, which in some cases requires a special purpose vehicle to be established.

For industrial tenant negotiations specifically, the most workable model described was amortising the cost of the solar system over the term of the lease, so the tenant pays a modest rent increase that is more than offset by their reduction in energy costs, while the landlord retains the asset value and any associated certificates after the tenant departs.

Tenant sophistication varies widely. Larger, more experienced tenants increasingly negotiate to own the system outright, including any associated certificates, and expect the landlord to fund construction, while smaller or less engaged tenants often need to be proactively brought into a program rather than initiating one themselves.

Sector-level evidence also identifies where direct capital expenditure remains dominant despite the broader shift toward PPAs and leasing: large, owner-occupied facilities such as chicken farms and steel manufacturers, where systems above 300 kW are typically self-funded as an extension of existing capital programs rather than financed separately.

VPP and Market Participation

VPP participation is growing from a low base. The survey confirms that demand charge reduction (74.4%) and peak demand management (62.8%) are the value streams most realised, ahead of resilience (32.6%), market services (32.6%) and network support (23.3%). Participation faces structural constraints: only 21.7% of C&I customers commonly adopt VPP participation. Aggregators typically require scale of 1 MWh or above, and the administrative complexity of VPP and demand response participation is beyond the capability of most C&I energy users without specialist support.

3.6 Landlord and Tenant Dynamics

This is the area of clearest convergence between an acknowledged literature gap and substantial new industry evidence. The literature review states directly that landlord-tenant misalignment is one of the most persistent structural barriers to C&I deployment, but that the literature offers limited solution-oriented analysis, leaving industry evidence to fill a significant gap. Survey data confirms the scale of the problem: 45% of respondents report that split incentives between tenants and landlords often or almost always create barriers to investment, and 73% identified responsibility for capital investment as the most common source of misalignment. 62% of respondents report being a service provider working with both landlords and tenants, suggesting most industry participants must navigate this dynamic directly rather than avoid it.

Interview evidence is the strongest source of insight on this theme and shows some internal disagreement the survey alone would not reveal.

Retail assets benefit from a relatively stable base building electrical load and strong tenant take up, which supports a mature embedded network model built on solar only generation, now moving into early battery energy storage deployments.

Industrial assets have far larger roof areas relative to base building load, so the generation opportunity is much greater in scale, but a smaller proportion of that generation is currently captured because tenant demand and internal revenue settings have not caught up with the available roof space.

Tenant appetite for solar on industrial sites is highly variable, ranging from tenants who decline any onsite generation and instead purchase certified renewable power from a retailer, through to cold storage and third-party logistics tenants who actively request the maximum system size because of their high baseline electricity use.

Several interviewees described the relationship as fundamentally adversarial under current settings: one said landlords have no obligation and no incentive to engage, are inherently inclined toward inaction, and that workable arrangements depend almost entirely on a pre-existing good relationship between the specific landlord and tenant rather than any structural mechanism. A second interviewee described seeing landlords seek as much as $20,000 a year in roof rental for a system generating only $15,000 a year in savings effectively destroying the business case entirely and estimated legal costs of roughly $12,000 to negotiate a single landlord contract covering make-good and end-of-term obligations. A landlord-side interviewee offered a different account of the underlying economics: rooftop solar revenue is typically immaterial to a property fund, in the order of $1 to $3 per square metre against substantially higher net rental income, meaning landlords have limited financial incentive either to resist or champion solar specifically. That interviewee identified the more durable problem as the prevailing PPA structure when linked to lease terms shorter than the expected asset life impose price pressure that landlords are reluctant to pass through to tenants.

A solar consultancy interviewee offered a more optimistic counter-example: some landlords pay for systems outright and pass on a discounted, hedged electricity rate to tenants as a lease feature, with electricity cost folded into the lease price rather than billed separately and is a model the interviewee said functions well in practice for at least one major property group.

> *“PPAs have broadly failed … lease terms don't match asset life.”* **Large Property Manager**

> *“Landlords want all the savings and tenants get none.”* **Qld C&I Installer**

> *“Landlords demanded payment for electricity generated by the tenant's own solar system.”* **C&I Project Manager**

On potential remedies, interview evidence converges more than it diverges. An accelerated asset write-off or write-down was raised independently by multiple interviewees as a workable, low-friction policy lever, on the basis that landlords already have a standing interest in asset depreciation and that the same incentive could in principle be extended to a tenant who funds the asset themselves. A standardised lease clause or model agreement addressing consumer energy resource rights, make-good obligations and value-sharing was also raised independently by more than one interviewee as a practical, near-term fix that would not require new legislation, consistent with the literature review's conclusion that a standardised green lease framework, supported by policy, is the most consistently identified reform pathway. One interviewee was notably more cautious about regulatory intervention, arguing that a landlord's right to control their own building should not be overridden; while still supporting non-binding, incentive-based reform such as a rates discount tied to enabling tenant solar. Section 4.4 sets out the case for an accelerated depreciation allowance and a standardised green lease framework in more detail.

3.7 Resilience, Reliability and Microgrids

The literature review states that resilience is becoming a major driver for C&I investment, particularly in sectors with critical loads, while noting that the economic value of resilience is difficult to quantify and varies substantially across sectors. Survey evidence supports a more measured version of this claim: only 15% of respondents describe resilience as a primary investment driver, with 57% describing it as important but secondary. Manufacturing and data centres were identified as the sectors placing the highest value on resilience, at 60% and 51% respectively, and cost was the leading barrier to resilience-focused investment at 56%.

Interview evidence is consistent with the survey's more measured framing and adds an operating principle the literature does not state explicitly: resilience investment in practice depends on the customer being able to attach a specific, calculable financial cost to an outage. One interviewee illustrated this with a manufacturing example in which a production stoppage of more than five minutes caused irreversible product loss, making a battery system that prevented just one outage a year pay for itself within two years on that basis alone. Without a comparably quantifiable loss, the interviewee said, resilience tends to be treated as a nice-to-have rather than an investment priority, even by customers such as data centres and hospitals that intuitively value continuity of supply.

A second interviewee corroborated this from the property side, noting that most tenants lack the technical literacy to value frequency control ancillary services or comparable system-level resilience attributes, meaning resilience value must currently be translated into a concrete dollar figure before it influences a C&I investment decision. A separate interviewee identified switchboard and circuit configuration, rather than financial valuation, as the more immediate practical constraint: most existing C&I switchboards are not configured to isolate critical loads, requiring a re-engineering exercise before any battery backup can be deployed for continuity purposes.

3.8 Incentive Mechanisms: SRES, LGC and LRET

The collapse in LGC prices emerged across interviews as one of the most consequential issues affecting C&I project viability, corroborated by survey data: 42% of respondents say price-signal reform under the LRET framework is needed this could be through either a minimum LGC price floor or a variable price band and 75% expect new projects to become financially viable again only once LGC prices reach $20/MWh or above.

Interview evidence converges strongly around a price range of $20 to $25 per certificate as the level needed to restore project viability. One interviewee, basing the figure on direct modelling with affected customers, noting that at the current price of roughly $3, the certificate effectively no longer functions as an investment driver, and linked the LGC price directly to project conversion rates, reporting that contract award rates have fallen to roughly 10% of levels seen two years earlier and attributing the fall not to competitive loss but to projects simply not proceeding to financial close. A separate interviewee offered a contrasting structural view, arguing the LGC mechanism itself was historically effective because it rewarded measured performance rather than upfront installation, and cautioned against any reform that replaces performance-based incentives with one-off rebates, while citing quality and compliance problems associated with the residential battery rebate scheme as a cautionary example for any expanded small-scale scheme.

On SRES, survey respondents identified high upfront capital costs as the leading reason variation is needed (71%), and 71% believe expanding eligibility would significantly or moderately improve the C&I business case. Increasing the system size cap was the most favoured form of variation (61%). Interview evidence is supportive but more specific about scale: most interviewees who addressed SRES directly proposed an upper threshold in the 200 to 500 kW range rather than the 1 MW figure sometimes discussed in policy circles, on the basis that this captures most underserved smaller C&I systems without requiring the wholesale redesign of planning and connection frameworks that begin to apply above 1 MW. It should be noted that further industry consultation on the expansion to 500kw or 1MW should be considered to avoid a possible quality gap occurring. Section 4.3 sets out the case for a 500kw/1 MW threshold in more detail, drawing on the full set of SRES-specific survey results.

> ***“Survey Finding (Q32):*** *50% of respondents say SRES variation would 'significantly improve' the business case for C&I DER under current tariff structures. A further 21.1% say it would 'moderately improve' it while 71% see meaningful benefit, making this the single clearest policy signal from the survey.”*

The wider Commonwealth and state policy architecture compounds the problem. SRES caps out at 100 kW, creating a cliff edge where a 99 kW system receives support and a 101 kW system receives none. The Commonwealth's Contracts for Difference (CfD) mechanism, under the Capacity Investment Scheme, involves a complex, costly application process that is effectively inaccessible to C&I-scale projects, effectively excluding the mid-scale sector both by scale threshold and by process complexity. No Commonwealth tax incentive specifically targets C&I solar or storage, though the instant asset write-off has periodically influenced investment decisions.

State settings vary widely. Victoria's Energy Upgrades program is the most active state-level scheme for C&I DER, but it does not recognise export, thus creating misalignment with optimal system design and DNSP approval delays of up to five months are undermining program compliance and payment timelines. New South Wales has reformed its connection processes and is among the more progressive jurisdictions on dynamic operating envelopes and flexible exports. Queensland's connection cost structure adds roughly $9,000 to $10,000 once a system exceeds 30 kW. South Australia leads on DER policy and network flexibility arrangements. Other jurisdictions vary significantly in their frameworks and support levels.

The net effect of this architecture: systems between 100 kW and 30 MW are too large for SRES, unable to benefit from collapsed LGC prices, excluded from CfDs, and burdened by inconsistent DNSP processes and tariff structures not designed for flexible demand or storage. The missing middle has no coherent policy home and the evidence shows the cost of that absence in halted projects, under-sized systems and suppressed investment.

3.9 International Comparator: Germany's 2024 Connection Reform

This report's literature review and survey instrument do not directly address international connection reform precedents, making interview evidence the primary source on this theme. A 2024 German reform removed the requirement for a costly system certification step for systems between 135 and 500 kW, provided that grid export was capped at 270 kW. This was a compromise that gave network operators confidence that connection liberalisation would not produce uncontrolled grid impacts.

Interview reactions to this model were broadly favourable but consistently qualified. One interviewee assessed that a capped-export, low-administration pathway would help reduce delay for systems in the 200 to 500 kW range, but judged it would not significantly move overall investment, given the larger constraint is the weak underlying business case created by low certificate prices rather than connection administration itself. A second interviewee was more directly positive, noting that a comparable network in Queensland was already independently moving toward a similar low-cost approval pathway for systems committing to limited or zero export, and estimated that an equivalent reform could cut typical commercial connection turnaround from roughly three months to under six weeks. A community energy interviewee raised the most significant caveat: Australia's regional distribution networks feature long, low-population feeders with materially different voltage stability characteristics to Germany's denser network, meaning a capped-export model calibrated for urban or semi-urban conditions may not transfer cleanly to regional and rural Australian feeders without separate calibration. A third interviewee supported the principle but queried the precise export cap, suggesting the appropriate export-capacity proportion should be tested against Australian DNSP risk tolerances rather than imported directly from the German figure.

3.10 Summary of Quantitative Survey Indicators

The table below summarises the survey indicators referenced throughout this section, drawn from the Smart Energy Council Members Survey 2026 (up to 61 respondents, depending on the question).

Theme	Indicator	Result
Drivers	Cost savings as top investment driver	94.7%
Drivers	Confidence in solar/storage business case (avg, 1-4 scale)	2.88
Connection	Length of approval times cited as a top barrier	70.9%
Connection	Connection issues materially change outcomes (sometimes/frequently)	84.9%
Connection	Governance unclear - connection requirements	82.1%
Tariffs	Demand charges most influence system sizing	63.0%
Tariffs	Tariffs support C&I investment 'very well'	2.0%
Data	Data access rated poor or limited	60.9%
Data	Interoperability issues rated significant	81.4%
Financing	Revenue uncertainty as top financing barrier	78.3%
Financing	Financiers rated cautious on C&I batteries	40.0%
Landlord/Tenant	Split incentives often/almost always a barrier	45.5%
Landlord/Tenant	Capital investment responsibility as top misalignment	73.5%
Resilience	Resilience as a primary investment driver	15.2%
Resilience	Cost as leading barrier to resilience investment	55.6%
LGC/LRET	Expect viability to return only above $20 LGC	75.0%
SRES	High upfront capital cited as top barrier needing SRES variation	71.1%

4. Strategic Recommendations

4.1 Standardise and Accelerate Connection Processes

Regulators and distribution networks should establish mandatory connection timeframes with enforceable performance metrics, and require networks to publish indicative, low-cost connection outcomes before a customer commits capital. This responds directly to the strongest and most convergent finding in the evidence base: 71% of survey respondents cite approval length as a leading barrier, 82% identify connection requirements as the least governed area, and interview evidence documents specific cases of multi-month delay and post-contract cost discovery. A capped-export, reduced-administration pathway for systems in the 100 to 500 kW range, informed by the German 2024 reform, should be trialled in at least one Australian jurisdiction and calibrated to local network conditions rather than imported directly.

Connection process reform is the highest-priority structural reform identified across both the survey and all practitioner interviews. The evidence is clear: delays, cost step-changes and inconsistency across DNSPs are deterring investment and stalling projects. Reform should focus on:

- Mandatory time-bound connection approval processes, with statutory timeframes for different system size categories and enforceable consequences for DNSPs that exceed them.
- Standardised connection requirements for systems in the 30 kW to 1 MW range, reducing the jurisdictional variation that currently adds complexity and cost.
- Transparent, freely accessible hosting capacity data at the feeder level, enabling early-stage project planning without expensive studies.
- A standardised 'connection product' for mid-scale systems below 5 MW, giving developers a known cost and timeline before committing project development expenditure.

> *“Zero-export systems should be exempt from grid connection application… just notify and go.”* **C&I Installer**
>
> ***“Survey mandate:*** *70% of respondents selected 'improved connection processes' as a top advocacy priority, equal first with government support for C&I energy storage and ahead of all other options. Connection requirements are also the most cited area of governance confusion at 82.1% of respondents being dissatisfied.”*

4.2 Reform Network Tariffs Toward Long-Term Cost Reflectivity

The Australian Energy Regulator and jurisdictional bodies should prioritise clear, long-term tariff pathways over further short-term tariff complexity, and examine the specific structural problem identified in interviews: annual or infrequent demand tariff resets that convert a non-firm operating saving into a firm cost exposure for behind-the-meter battery customers. This responds to survey findings that only 2% of respondents see current tariffs as supportive, and 54% prioritise long-term pathway clarity over other reforms.

4.3 Restore a Credible Certificate Price Signal

Government should restore investment confidence in the LRET, or design a successor mechanism, that delivers a certificate price in the $20 to $25/MWh range identified consistently across interviews and the survey as the level required to restore project viability. Any reform should preserve the performance-based design that rewards measured generation, rather than reverting to upfront, installation-based rebates this reflects interviewee concerns about the quality and compliance problems associated with one-off incentive schemes.

SRES Threshold Reform

The 100 kW SRES threshold is a structural artefact that creates a cliff-edge effect in support, and the survey evidence for reform is the strongest quantitative signal in the dataset. The case for reform rests on five lines of evidence:

- 50% of respondents say SRES variation would 'significantly improve' the C&I business case under current tariffs; a further 21.1% say it would 'moderately improve' it. 71% see meaningful benefit overall, with only 2 respondents (5.3%) saying it would have no impact (Q32).
- 81.1% say SRES changes would help overcome connection-related barriers for larger C&I systems. 32.4% 'significantly' and 48.6% 'somewhat' (Q33).
- 61.1% prioritise increasing the system size cap as the most effective SRES variation; 58.3% prioritise introducing a C&I-specific SRES category (Q36).
- 47.4% say landlord-funded installations and PPAs would benefit most from SRES variation (Q34).
- For the split-incentive segment, 67.6% see meaningful benefit from SRES variation in reducing split-incentive barriers. 21.6% 'significantly' and 45.9% 'somewhat' (Q35).

The most plausible threshold for reform is 1 megawatt. Above this level, state planning permit frameworks and other regulatory considerations become relevant, making 1 MW a natural and administratively workable break point. However as noted earlier; Industry consultation on the expansion to 500kw or 1MW should be considered to avoid a possible quality gap occurring.

A Mid-Scale Policy Mechanism

The collapse of LGC prices has left mid-scale projects without a viable policy framework. Three complementary mechanisms can close this gap:

- **Medium-Scale Renewable Energy Scheme (MSRES).** Nominated here as a new performance-based certificate scheme for systems between 100 kW and 30 MW, with a floor price sufficient to restore investment confidence. Interviewees consistently identified $20-$25/MWh as the approximate floor for viability. The scheme should stay administratively simple and include batteries and flexible demand technologies. One interviewee recommended a new Renewable Energy Guarantee of Origin (REGO) framework as a potential vehicle to achieve this outcome.
- **Expand SRES to at least 1 MW.** By increasing the STC threshold to 500 kW or 1 MW eliminates the artificial under-sizing driven by the 100 kW cliff edge. This is the fastest and most administratively straightforward reform available to the Commonwealth Government.
- **German-style export-capped fast-track pathway**. Via a successful trial; adopting Germany's 2024 model for systems between 135 and 500 kW (export capped at 270 kW, no complex certification; see Section 3.9) reduces DNSP workload, supports grid stability and unlocks mid-scale rooftop solar at a scale Australia has not previously achieved.

4.4 Establish a Standardised Commercial Green Lease Framework

Government and industry bodies should develop and promote a standardised lease clause or model agreement addressing consumer energy resource rights, make-good obligations, value-sharing and accelerated asset write-off eligibility for both landlords and tenants. This responds to the clearest gap between the literature and the evidence base: the literature acknowledges landlord-tenant misalignment as a persistent barrier without offering solutions, while interview evidence converges on accelerated depreciation and standardised lease terms as practical, achievable near-term reforms that do not require new legislation.

Accelerated Depreciation

As a faster, lower-complexity step ahead of full lease standardisation, government should legislate an accelerated depreciation allowance for landlord-funded or tenant-funded consumer energy resource assets, extending the same schedule to whichever party bears the capital cost. Landlords already depreciate capital improvements to a building; an accelerated schedule for solar, battery and switchboard works would simply bring forward a tax benefit they already expect to receive over time. Extending an equivalent allowance to a tenant who funds the asset themselves would remove one of the few asymmetries currently working against tenant-funded installations, where the tenant carries the capital cost and connection risk but, under current depreciation schedules, recovers the tax benefit only slowly and may not occupy the premises long enough to capture the full benefit at all.

This measure can be implemented through existing tax settings rather than energy market reform. This was supported independently by multiple interviewees as the most readily achievable lever available, and was contrasted favourably with the more complex, multi-year work required to standardise lease clauses across the property sector. A write-down could be legislated and take effect well before any broader green lease framework is agreed and adopted at scale. A landlord-side interviewee added a complementary observation; because rooftop solar revenue is typically immaterial to a property fund's overall return, a faster write-down would not meaningfully change a landlord's appetite to initiate a project, but could still remove a point of friction in negotiation by giving the landlord a clear, quantifiable benefit to set against a tenant's request to install or expand a system.

Two qualifications apply. First, an accelerated write-down does not address the split-incentive problem itself. It improves the economics of whichever party funds the asset but does not resolve disagreement over who that party should be. Second, the value of an accelerated write-down is contingent on the asset owner having sufficient taxable income against which to claim the deduction, meaning the benefit is more immediately useful to an established landlord or larger tenant than to a smaller or newer business. It should be treated as a complement to, rather than a substitute for, the standardised lease and value-sharing reforms above.

4.5 Mandate National Data Access and Interoperability Standards

Regulators should mandate consistent, low-cost access to hosting capacity, feeder constraint and dynamic operating envelope data, and develop national interoperability standards for distributed energy resource equipment and energy management systems. This is supported by convergent evidence across all three streams: the literature identifies data access as the single highest-leverage enabler, 81% of survey respondents rate interoperability as a significant issue, and interview evidence documents specific cases where opaque network data led to under-utilised hosting capacity and unplanned cost exposure. The industrial development interviewee wanted network authorities to take a more proactive role in identifying suitable sites on large landholdings and approaching landholders directly to discuss partnership opportunities for batteries or network infrastructure, rather than leaving landholders to initiate every conversation themselves.

4.6 Implementation Roadmap

The reforms above need sequencing to deliver early wins, build institutional capability and create a predictable investment environment. The table below ranks each reform by survey evidence, expected impact and feasibility; the roadmap that follows spans three horizons.

Reform	Survey Evidence	Impact	Feasibility	Priority
Connection process standardisation	70% top advocacy priority (Q27); 82.1% cite governance confusion (Q26); 70.9% flag approval times (Q8)	High	Moderate	Immediate
SRES threshold to 500kw/1 MW	50% say 'significantly improves' business case; 71% see meaningful benefit; 81.1% say it helps overcome connection barriers (Q32, Q33)	High	Moderate	Immediate
Government support for C&I energy storage	70% top advocacy priority; equal with connection reform; reflects battery financing gap	High	Moderate	Immediate
Accelerated depreciation for solar and batteries	Confirmed by owner-occupier segment interviews; fits existing tax framework; low design complexity	Medium-High	High	Short-term
LGC floor price / mid-scale support	44.4% support price floor; 75%+ say above $25/MWh or unsure of required price	High (mid-scale)	Moderate	Short-term
Green lease framework	73.5% cite capital responsibility as misalignment; 39.4% say split incentives create barriers often/almost always	Medium	High	Short-term
Mandatory network data transparency	54.5% cite real-time data and hosting capacity gaps; 0% rate data access as 'excellent'	Medium	Moderate	Short-term

Horizon 1: Immediate Actions (0-6 Months)

These reforms deliver rapid impact, reduce uncertainty and build momentum. They require minimal legislative change and can be implemented through regulatory direction or coordinated industry action.

Action	Lead	Why It Matters
Establish a national C&I DER Taskforce	DCCEEW with AER, AEMO, DNSPs, industry	The missing middle has no institutional home and this fills that gap
Expand SRES to 500 kW or 1 MW	Commonwealth: regulatory amendment	Ends artificial under-sizing driving SRES distortion across the sector
Publish draft national technical standards for C&I DER	AEMO and AER: consultation paper	Begins harmonising inconsistent DNSP requirements
Launch national DNSP tariff database	AER: administrative directive	Low cost, high impact; eliminates manual search burden across the industry

Action	Lead	Why It Matters
Begin design of the MSRES or incorporate into a new REGO framework	DCCEEW: consultation and design	Mid-scale viability has collapsed; design must begin immediately to avoid a multi-year vacuum

Horizon 2: Structural Reforms (6-18 Months)

These reforms require regulatory change, rule amendments or coordinated national action, and address the core structural barriers.

Action	Lead	Why It Matters
Implement mandatory connection timeframes	AER: rule change	70.9% cite long approval times; highest-impact single reform
Introduce zero-export notification pathway	AER and DNSPs: national guideline	Unlocks thousands of projects; zero network risk for zero-export systems
Publish real-time hosting capacity maps	DNSPs: regulatory requirement	DNSP estimates can be off by 100%; eliminates costly late-stage surprises
Mandate interval data access via open APIs	AER: rule change	60.9% rate data access poor or limited; foundational enabler of optimisation
Introduce standardised green lease clauses	State governments and property councils: model templates	Resolves landlord-tenant misalignment across large commercial roof areas

Horizon 3: System Transformation (18-36 Months)

These reforms reshape the long-term structure of the C&I energy landscape:

- Implement the MSRES or new REGO framework, providing a stable, long-term incentive for 100 kW to 30 MW systems. The reform that interviewees unanimously identified as most critical to restoring mid-scale viability.
- Introduce export floor prices for C&I customers, preventing the perverse outcome of customers being charged for clean energy generation during negative wholesale price periods.
- Establish local energy markets for C&I DER, enabling C&I customers to trade energy locally and support VPPs, microgrids and industrial precinct electrification.
- Reform embedded network regulation, clarifying backstop arrangements and enabling microgrid deployment at scale across regional and industrial Australia.

4.7 Case Studies

Case studies provide the most vivid evidence of how structural barriers translate into practical project outcomes. The following examples were drawn from practitioner interviews and validated against survey data.

Port Melbourne Food Manufacturer: When Revenue Uncertainty Kills the Deal

A food manufacturing facility operating across two 1 MW transformers, with a high, consistent load profile ideally suited to solar-plus-storage, could not proceed with a 2 MW solar and 7 MWh battery system. The commercial case generated only 8% savings at 15 cents/kWh, equating to approximately $150,000 per year. FCAS and arbitrage value streams were too volatile to support financing: the funder would not accept arbitrage risk, the customer would not accept bill volatility, and retailers could not offer firmed, predictable value streams. The project did not proceed. Not because of the technology or the site, but because revenue uncertainty made financing structurally impossible.

Hybrid Wind-Battery and Solar Project: Connection Cost Uncertainties

A multi technology development encountered a series of diverse connection challenges over the projects history. In 2011 for the original connection, an initial quote of $250,000 became a final cost of $1.6 million for feeder upgrades. In 2021, A $30,000 feeder study, taking 8 to12 months, revealed the DNSP had estimated solar PV export / hosting capacity at half the actual level. In 2026, during battery grid connection, DERMS requirements emerged only at the final stage of GPS approval. The project succeeded only because the organisation had grant funding, deep internal expertise and strong relationships with the DNSP. Without any one of those advantages, the project would not have proceeded. This case is not exceptional, but illustrative of a system that lacks transparency, predictability and standardisation.

Steel Manufacturer: Charged for Exporting Solar

A steel manufacturer, with 1.5 MW of export capacity, was charged for exporting solar energy during periods of negative wholesale prices. The customer disabled export despite DNSP interest in local generation, reducing the value of the solar system and undermining the business case for future expansion. This case demonstrates the misalignment between wholesale market signals, DNSP needs and customer economics, and the need for an export floor price that prevents customers being penalised for generating clean energy.

Cold Storage Facility: Landlord Demands Payment for Tenant Solar

A cold storage tenant sought to install solar to reduce operating costs. The landlord initially agreed, then demanded payment for electricity generated by the tenant-funded system. The project stalled, and legal costs to resolve the dispute exceeded $12,000 before any panel was installed. This case is not unusual. It reflects the structural absence of standardised frameworks for allocating the benefits of tenant-funded solar in leased commercial properties.

The 100 kW STC Threshold: Systemic Under-Sizing

Across multiple practitioners and numerous sites, the same pattern recurs, customers need 200 to 400 kW systems but install 100 kW systems to access STCs, because LGCs at $3 to $4/MWh are not worth the administrative burden and no other viable incentive mechanism exists for mid-scale systems. As a direct result of this structural gap in policy design, Australia's mid-scale solar potential remains largely untapped.

4.8 Closing Observation

The evidence base shows that no single reform unlocks the missing middle in isolation. Connection reform creates the conditions for projects to proceed; tariff reform and a credible certificate price determine whether those projects are financially viable; and landlord-tenant reform determines whether a substantial share of the addressable market such as multi-tenant commercial property can participate at all. The evidence supports coordinated action across government, regulators, distribution networks and industry, rather than any single intervention.

This report makes a clear case that Australia's C&I sector is significantly under-investing in distributed solar, battery storage and electrification relative to its potential, and that the primary causes are policy and regulatory rather than technological. The technology exists and continues to improve. The economics are sound for a meaningful share of C&I sites and are strengthening as storage costs fall and tariff structures evolve. Appetite for investment is present; every interview and the survey data confirm that financial savings are a powerful driver. But that appetite is being frustrated by connection delays, threshold gaps, split-incentive problems and a policy environment that is creating uncertainty and project paralysis.

The May 2026 member survey gives unambiguous direction on advocacy priorities: 70% of respondents cite both connection process reform and government support for C&I energy storage as top priorities, and SRES reform commands 71% support for meaningful improvement. Data access and tariff reform are secondary but consistent themes, and the landlord-tenant challenge is pervasive with 39.4% of respondents experience split-incentive barriers 'often' or 'almost always'.

Three Overarching Findings

- **The economics are sound but not strong enough to overcome internal capital competition without policy support.** Payback periods of 3 to 6 years are achievable, but internal hurdle rates of 10 to 15% IRR are hard to reach consistently. The survey confirms the tension: 67.9% of respondents cite capital constraints and 30.4% report customer uncertainty or lack of confidence in the business case.
- **Structural barriers, not technology, are the dominant constraint.** Solar, batteries and EMS platforms are mature and widely available; the barriers are regulatory, commercial and institutional. Connection delays alone affect 84.9% of projects.
- **The policy environment is fragmented, inconsistent and in some respects actively discouraging.** There is no coherent national framework for the missing middle: SRES caps out at 100 kW, LGC prices have collapsed to $3 to $4/MWh, and the Capacity Investment Scheme is inaccessible to mid-scale projects. As one practitioner put it: “That sector has just never had a shot.”

These barriers do not operate in isolation they compound. Connection delays combined with tariff volatility increase project cancellation risk. Landlord-tenant misalignment combined with mid-scale policy collapse leaves large roof areas permanently unused. Data gaps prevent battery optimisation, eroding the economics that might otherwise overcome other barriers. Connection costs combine with electrification requirements to suppress grid upgrades and DER investment. The missing middle cannot scale without addressing this web of structural constraints together.

> *“We don't need massive incentives, just a little encouragement and a system that works.”* **C&I Installer**

The benefit to Australia's energy system from unlocking the C&I sector's potential is substantial: gigawatts of distributed generation, hundreds of megawatt-hours of flexible storage, and significant demand-side resources that can reduce system costs for all electricity consumers. This research is the foundation for the Smart Energy Council to make that case with evidence, precision and force.

5. Appendix: References and Methodology

5.1 Literature Review Sources

The literature review synthesises more than 80 sources across six categories, including the AEMO Integrated System Plan, AEMO Connections Scorecard, AER Network Tariff Reform, ESB Post-2025 Market Design, CSIRO Renewable Energy Storage Roadmap and GenCost, the National Consumer Energy Resources Roadmap, the National Battery Strategy, ANU BSGIP research on battery storage and grid integration, ARENA dynamic operating envelope trial and working group outputs, UNSW and UTS pricing and network research, Clean Energy Council and Nexa Advisory C&I market analyses, and industry case study material from technology providers and trade publications. Full source listings, including hyperlinks, are maintained in the literature review appendix to the main report.

5.2 Survey Methodology

The Smart Energy Council Members Survey 2026 was conducted via electronic distribution to the Council's membership during April and May 2026, with a parallel LinkedIn promotion to broaden response beyond the core membership. The survey received up to 61 responses depending on the question; later questions, particularly those addressing tenant-landlord dynamics, received fewer responses since not all respondents operate in multi-tenant contexts. Respondents were drawn from technology providers, installers and integrators, developers, investors and financiers, network and market participants, and consultants and advisory firms. The survey combined multiple-choice, multi-select, ranking and weighted-average Likert-style rating questions with open-text response fields.

Survey Results Summary

The tables below present a complete summary of the quantitative results from the Smart Energy Council Members Survey 2026 (EDM), conducted in May 2026. Respondent count: 61 across questions. All figures are as reported by the survey platform.

A.1 Market and Customer Context

Q1: Organisation Category	Responses	Share
Installer or integrator	20	35.1%
Technology provider	17	29.8%
Other	15	26.3%
Consultant or advisory firm	8	14.0%
Network or market participant	8	14.0%
Developer	2	3.5%
Investor or financier	4	7.0%

A.2 Investment Drivers and Business Case Confidence

Q4: Drivers for C&I Customer Investment	Responses	Share
Cost savings	54	94.7%
Sustainability commitments	28	49.1%
Resilience and reliability	26	45.6%

Q4: Drivers for C&I Customer Investment	Responses	Share
Electrification	17	29.8%
Grid resilience	17	29.8%
Corporate reporting requirements	8	14.0%
Supply chain expectations	6	10.5%

Q5: Confidence in business case for solar and storage - weighted average 2.88/4 (scale: Not Confident / Uncertain / Moderately Confident / Very Confident). 48.2% moderately confident; 21.4% very confident.

A.3 Connection and Tariff Issues

Q8: Most Common DNSP Connection Challenges	Responses	Share
Length of approval times	39	70.9%
Slow response times	37	67.3%
Changing technical requirements	28	50.9%
Lack of transparency	22	40.0%
Export limits	20	36.4%
Hosting capacity uncertainty	17	30.9%

Q9: How often connection issues materially change system design or commercial outcomes - weighted average 4.21/5 (1 = Never, 5 = Frequently). 35.9% say 'frequently'; 49.1% say 'sometimes'; 15.1% say 'rarely'.

Q10: How well current tariffs support C&I investment in flexibility and storage - weighted average 3.20/5 (1 = Not at all, 5 = Very well). 58.8% rate as 'poor'; 31.4% as 'adequate'; 2.0% as 'very well'.

A.4 SRES Variation

Q32: How much would SRES variation improve the business case?	Responses	Share
Significantly improve	19	50.0%
Moderately improve	8	21.1%
Slightly improve	7	18.4%
No impact	1	2.6%
Unsure	3	7.9%

Q36: Which SRES Variations Would Most Effectively Support C&I DER?	Responses	Share
Increasing the system size cap	22	61.1%
Introducing a C&I-specific SRES category	21	58.3%
Streamlining compliance and installation processes	20	55.6%
Including batteries or flexible demand technologies	20	55.6%
Adjusting certificate values for larger systems	13	36.1%

A.5 LGC Price Reform

Q39: LGC Price Level for Project Viability	Responses	Share
Above $25/MWh	15	41.7%
Unsure / depends on project type	12	33.3%
$20–$25/MWh	3	8.3%
$15–$20/MWh	4	11.1%
$10–$15/MWh	1	2.8%
$5–$10/MWh	1	2.8%

A.6 Landlord-Tenant Issues

Q43: Most Common Misalignment Issues	Responses	Share
Responsibility for capital investment	25	73.5%
Allocation of operational savings	20	58.8%
Lease duration and renewal uncertainty	17	50.0%
Responsibility for connection processes	17	50.0%
Responsibility for maintenance	10	29.4%
Control of CER assets	8	23.5%
Data access and metering	5	14.7%

A.7 Advocacy Priorities

Q27: Top Advocacy Priorities for the Smart Energy Council (up to 2)	Responses	Share
Government support for C&I energy storage	28	70.0%
Improved connection processes	24	60.0%
Tariff reform	24	60.0%
Tenant and landlord solutions for C&I deployment	15	37.5%
Local market development	12	30.0%
National data standards	8	20.0%

Note: respondents could select up to two options for Q27. Percentages are of 40 respondents who answered this question.

A.8 Further Survey Detail

The points below cover remaining survey questions referenced only briefly, or not yet referenced, in the body of this report.

- Q2 (C&I segments worked with): mixed portfolio 45.6%, manufacturing 40.4%, logistics and warehousing 36.8%, agriculture and retail 24.6% each, property and real estate 21.1%, public sector 15.8%, data centres 10.5%.
- Q6 (biggest barriers to customer decision-making): capital constraints 67.9%, complexity of technology 44.6%, uncertain value streams 35.7%, internal governance 26.8%, connection uncertainty 25.0%, lack of data 12.5%.
- Q7 (ease of navigating C&I connection processes, 0-10): average 7, across 57 respondents (388 total points).
- Q17 (financing barriers): revenue uncertainty 78.3%, risk allocation 41.3%, lack of standardised contracts 34.8%, technology risk 26.1%, creditworthiness 19.6%.
- Q18 (financier willingness to support C&I battery projects): 22.2% very willing, 33.3% moderately willing, 40.0% cautious, 4.4% unwilling (weighted average 2.27/4).
- Q20 (predictability of operational performance and revenue): 4.5% highly predictable, 52.3% moderately predictable, 38.6% variable, 4.5% unpredictable (weighted average 2.43/4).
- Q21 (operational challenges): network constraints 68.2%, customer operational constraints 40.9%, inverter limitations 29.5%, energy management system performance 29.5%, data quality 27.3%, maintenance service provision 13.6%.
- Q40/Q41 (leased premises involvement and role): 42.9% of respondents say CER projects 'sometimes' involve leased premises and 31.4% say 'often'; respondents are most commonly a service provider working with both parties (62.9%), with the remainder split across landlord, tenant and dual roles.
- Q49/Q50 (operational responsibility in leased premises): rated 'moderately' to 'very' challenging by 70.6% of respondents (weighted average 2.82/4); the leading operational issues are maintenance responsibility (53.1%), building-management-system integration (31.3%) and metering/data access (34.4%).
- Q53/Q55 (connection agreements and tariff issues in leased premises): the tenant holds the connection agreement in 32.4% of cases and the landlord in 26.5%; connection upgrade costs (63.6%) and demand charges (36.4%) are the most challenging tariff or network issues.
- Q56/Q57 (resilience alignment and funding in leased premises): only 24.3% of respondents describe tenants and landlords as 'fully' or 'mostly' aligned on the value of resilience; responsibility for paying for resilience investment 'varies by project' for 36.4% of respondents.
- Open-ended questions (Q28–Q30, Q37, Q58–Q60): the survey included six free-text questions on the biggest five-year opportunity (28 responses), the single biggest barrier (30 responses), additional insights (15 responses), priority SRES changes (17 responses), and tenant-landlord barriers, successful arrangements and reforms (16, 14 and 14 responses respectively). These responses were used qualitatively, alongside the practitioner interviews, to inform the analysis and recommendations in Sections 3 and 4, and are not separately tabulated here.

5.3 Interview Framework

Ten stakeholder interviews and policy discussions were conducted between April and May 2026, using a consistent semi-structured question framework covering: investment drivers and decision timing; connection processes and network interactions; tariffs and market signals; data access and consistency; business models and financing; resilience and reliability; technology and standards; landlord-tenant dynamics; and policy and regulatory reform priorities, including discussion of a 2024 German connection reform as an international comparator. Interviewees were given an undertaking that draft findings would be returned to them for review prior to finalisation. Interviewees cited in this report include specialists in measurement and verification and certificate creation, a landlord-side energy lead at a major diversified property group, C&I solar and battery developers and installers operating at small, medium and utilityadjacent scale, a community energy and midscale generation specialist, and a commercial solar and battery consultancy.

5.4 Limitations

This report draws on a literature review with the strongest evidence in system planning and regulatory domains and comparatively underdeveloped C&I-specific business model and governance literature; a survey with declining response rates on later, more specific questions; and ten interviews that, while detailed, represent individual practitioner perspectives rather than a statistically representative sample of the C&I sector. Findings should be read as a triangulated, qualitative-quantitative evidence base rather than a definitive census of industry opinion, and the report's recommendations are offered on that basis.

5.5 Glossary

Term	Definition
CfD	Contract for Difference; a long-term energy contract used under the Capacity Investment Scheme
DER	Distributed energy resources; solar, batteries, flexible loads and other small-scale generation and storage assets
DNSP	Distribution Network Service Provider; the company that owns and operates the local electricity distribution network
DOE	Dynamic Operating Envelope; a real-time, network-aware limit on a DER asset's export or import capacity
FCAS	Frequency Control Ancillary Services; market services for maintaining grid frequency stability
Hosting capacity	The amount of additional generation or load a feeder can accommodate without requiring network upgrades
LGC	Large-scale Generation Certificate; a certificate created for each MWh of eligible large-scale renewable energy
LRET	Large-scale Renewable Energy Target; the Commonwealth scheme requiring retailers to source a set proportion of electricity from renewable sources
Missing middle	Systems between 100 kW and 30 MW; too large for SRES, too small or uneconomic for LGCs or CfDs. This includes potential front-of-the-meter sites. Eg. farms, warehouses, closed landfill and other greenfield sites.
MSRES	Medium-Scale Renewable Energy Scheme; the new policy mechanism proposed in this report for 100 kW–30 MW systems
PPA	Power Purchase Agreement; a contract for the sale and purchase of electricity output from a renewable energy system
SRES	Small-scale Renewable Energy Scheme; the Commonwealth scheme supporting solar and other small-scale renewables up to 100 kW
STC	Small-scale Technology Certificate; a certificate created under SRES for each unit of electricity generated or displaced by an eligible small-scale system
VPP	Virtual Power Plant; a network of distributed energy assets, aggregated and dispatched as a single resource