LESSONS FROM THE 2026 CHARGED INITIATIVE AUSTRALIA STUDY TOUR

WHAT U.S. REGULATORS LEARNED • APRIL 2026

In March 2026, the CHARGED Initiative brought nine U.S. utility commissioners and staff on a study tour to Australia, a country that has developed a blueprint for managing an electricity grid led by distributed energy. Australia has the highest rooftop solar penetration in the world, and its utilities, regulators, and market operator have spent the last decade innovating to create a customer-focused, flexible grid that continues to evolve rapidly. This report captures what the study tour participants learned and what Australia's experience means for U.S. regulators navigating their own distributed energy resource transitions.

INTRODUCTION

The CHARGED Initiative — a collaboration between GridLab, Advanced Energy United, and RMI — sponsors study tours for state regulators to bring home lessons from other countries that are in the midst of grid transitions. After two tours to Great Britain in 2025, CHARGED visited Australia in March 2026 with nine utility commissioners and staff from across the U.S.

Australia was chosen because it is living, at scale, the future that awaits U.S. regulators as distributed energy technology costs fall and consumer engagement and participation in the energy system increases. One in three Australian households has rooftop solar, the highest penetration in the world (and it is one in two in the state of South Australia). Home batteries are growing fast, following a similar trajectory. The grid is under real pressure to respond to bottom-up consumer choices. Australian energy market participants and decision makers have had to innovate in response, often creating the playbook in real time.

Study tour participants visited distribution network operators, retailers, the wholesale market operator, the national regulator, and national and state government agencies. They came back with a mix of admiration and practical ideas. This report provides the context that U.S. readers need in order to understand Australia's story as well as the biggest takeaways that traveled home with study tour participants.

UNDERSTANDING THE AUSTRALIAN CONTEXT

U.S. regulators will recognize some of what they find in Australia. The challenges of integrating distributed resources into a grid not originally built for them are familiar, as are the debates about how to ensure the benefits of rooftop solar reach all customers. Also familiar are the difficulties of engaging consumers and recovering fixed network costs as the customer base changes. What is different is the scale of the opportunity and challenge Australia is already actively managing, and the institutional tools and simple yet elegant technical solutions it has developed in response.

The consumer energy boom

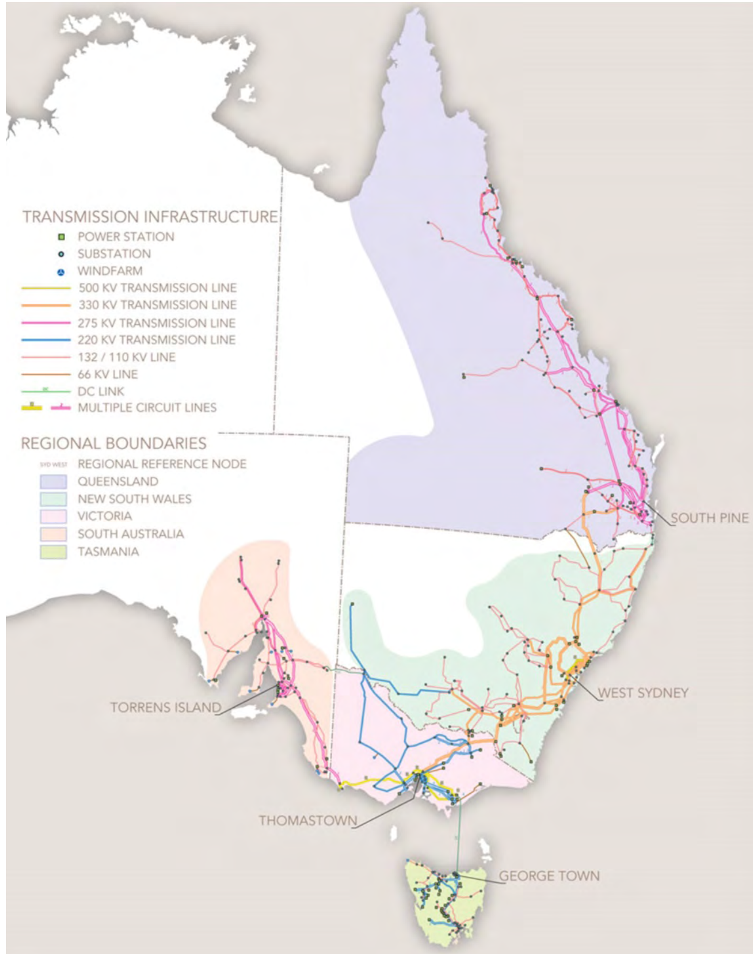
The high rates of solar adoption in Australia are due in large part to the low costs they have achieved. Low installed costs are the product of streamlined permitting, lightweight installation rules, and strong, audit-based installer accountability, rather than the more burdensome utility and local government oversight of each connection, which is typical of the U.S. distributed solar market. In South Australia, so much solar flows onto the grid on sunny afternoons that the state regularly faces — and actively innovates to manage — minimum system load challenges, as the combined output from rooftop solar can exceed the entire state's load.

Home battery installations are now following the same curve, and accelerating fast. In the second half of 2025, monthly residential battery installations roughly doubled month over month, driven in part by a new federal subsidy program. By the end of 2025, according to a national government report, the 4.6 GWh of storage installed under the program exceeded the combined capacity of the 12 largest grid-scale batteries in the country — a milestone reached in six months.

The customer relationship is so integral to the Australian power market that Australians have abandoned the term distributed energy resources (DERs) in favor of *consumer* energy resources (CERs), a term coined by Energy Consumers Australia. The distinction reflects an understanding that the assets belong to consumers and that they play a central, not far flung, role in balancing and managing the energy system.

How the market works

Australia's main wholesale electricity market — the National Electricity Market, or NEM — is the closest analogue to Texas's ERCOT market that exists outside the U.S. It covers the most populous parts of the country and operates a five-minute, energy-only market with very high price caps and a negative floor. There is no nodal pricing; instead, zonal prices settle in each of the NEM's five regions, with transmission interconnections between regions playing a vital role in managing system integrity and making use of the regional diversity of Australia's abundant renewable energy



National Electricity Market
CREDIT | AEMO (VIA AEMC WEBSITE)

resources. The Australian Energy Market Operator (AEMO), which runs the NEM, procures ancillary services and can direct real-time responses from participants to maintain reliability, as well as supporting state and federal government-led resource procurement for capacity and reliability. A recent market review recommended keeping the NEM's energy-only design with some refinements, including increasing the visibility and dispatchability of distributed resources.

How market regulation works

Australia regulates wholesale and retail electricity at the national level, with some state regulatory overlay as well. Within the NEM, distribution utilities, known as distribution network service providers (DNSPs), competitive retailers, and market participants all fall under a unified regulatory framework. Two bodies handle the main regulatory functions: the Australian Energy Market Commission (AEMC) sets the high-level rules and the Australian Energy Regulator (AER) handles ratemaking and enforcement. The DNSPs operate under five-year revenue caps with separate allowances for operating costs and capital expenditure, performance incentives tied to reliability metrics, and a shared savings mechanism when spending comes in above or below the cap. Capital expenditure is split into RepEx (replacement expenditure), for aging assets reaching their end of life, and AugEx (augmentation expenditure), for grid expansion. This split enables the regulator to manage how it scrutinizes costs for maintaining grids versus extending electric service. Most non-monopoly services in the NEM regions are left to competitive markets — "contestable" services in Australian terminology — which include metering as well as retail supply. This more nationally consistent, disaggregated framework is one of the most significant structural differences from the U.S., where fifty separate state jurisdictions have authority over the regulation of distribution utilities and retail supply.

With that context in hand, here are four lessons that study tour participants brought home.

LESSON 1

ACT AND REACT: AN ACTION-FIRST, ADAPTIVE CULTURE

The observation that struck study tour participants most consistently was this: Australia takes action and then adapts the system to the new reality. It sets a direction, moves, and works out the details under real operating conditions. This appeared to be a deliberate posture, backed by regulatory structures that make adaptation easier than in the U.S. The tone was not one of risk indifference, but rather a different calibration: more tolerance for change, operational adaptation, and learning under real conditions.

The rooftop solar installation process is a straightforward example. In Australia, solar companies are responsible for every aspect of installation — permitting, compliance, and grid connection — and face penalties when audits reveal problems. There is no on-site utility representative, no approval required at every step. The system trusts installers and spot-checks them with a real risk of loss of grid connection certification for non-compliance. The result is fast, inexpensive, widespread installation. The U.S. approach — with its utility-by-utility interconnection queues, technical review requirements, and in many cases on-site utility inspections — as well as more stringent and costly local permitting regimes, produces slower and more expensive outcomes.

Rooftop solar in Melbourne, Australia.

The cost difference is striking. Distributed solar in Australia costs approximately one Australian dollar per watt installed — less than a third of typical U.S. costs. Some of that gap reflects geography, market scale, and supply chains that U.S. regulators cannot directly control. But a meaningful part reflects process. Although local government permitting is largely outside a utility regulator's direct authority, utility interconnection and inspection requirements, technical specifications, and application complexity are not. U.S. regulators and utilities may not be able to make solar cheap, but they can choose not to make it harder than it needs to be, and that choice compounds over millions of connections.

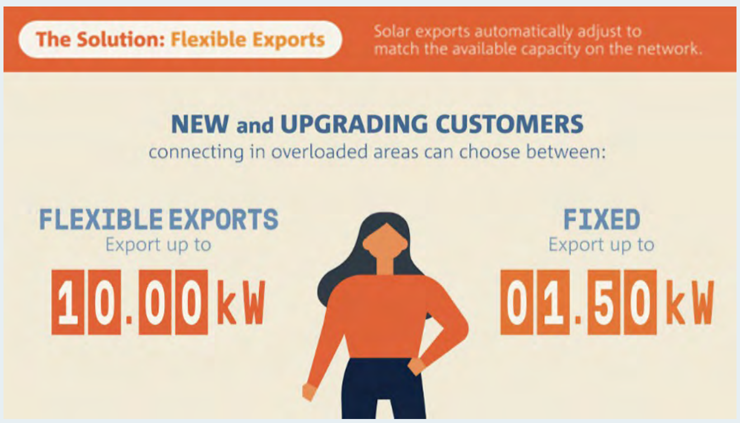
South Australia's distribution network operator, SA Power Networks (SAPN), offers another instructive example of adaptation to a new reality (see Box 1 for more details). As rooftop solar grew to levels that threatened grid stability, SAPN did not wait for a national solution, attempt to own and manage CERs, or call for a halt to installations. It repurposed funding to build a network innovation center, and then developed and implemented *flexible export limits* (also known as *dynamic operating* envelopes in Australia). This mechanism allows SAPN to communicate with each customer's solar inverter to vary how much each system can export at any given time according to available grid capacity. These operational solutions were built with the tools SAPN already had or could develop in-house, and leveraged existing communications infrastructure, including household Wi-Fi, rather than requiring a bespoke communication protocol and frequency.

SAPN'S FLEXIBLE EXPORTS — LETTING CONSUMERS CHOOSE

How South Australia doubled its solar hosting capacity without building new infrastructure

By 2021, South Australia faced a problem most grids will not encounter for years: so much rooftop solar that on mild spring days, the network could not absorb it all. The traditional response would have been to cap new connections or impose lower fixed export limits. SA Power Networks (SAPN) chose a different path.

SAPN's solution was to give customers a choice. When connecting a new solar system, customers could opt for a **fixed export limit of 1.5 kW per phase** — simple and predictable, but constrained — or a **flexible export limit of up to 10 kW per phase**, which the network could dynamically reduce during periods of grid stress and restore when capacity was available. SAPN's own modelling showed the flexible limit would be available at full capacity more than 98% of the time in most areas.



The offer was delivered through solar installers who were trained on the technical requirements, equipped with an online eligibility checker that showed historical export performance by address. The retailer and installer relationship — not the distribution network provider-to-customer relationship — was the primary communication channel, though SAPN branding was also used to improve consumer trust.

The numbers vindicated the approach. Once flexible exports became the standard offer at full rollout, more than 95% of eligible customers chose the 10 kW flexible option over the 1.5 kW fixed export limit.

The technical underpinning was built by SAPN itself: developing a communication standard for inverter-network interaction as part of the original flexible exports work, a standard that was subsequently adopted nationally as CSIP-AUS — the national smart inverter standard requiring new solar installations to be capable of receiving dynamic export instructions over the internet.

What this means for U.S. regulators: The action-first posture may be a cultural trait, but culture follows structure. U.S. regulators who want utilities to move faster can ask what structural changes would promote a similar adaptive posture — and whether current requirements are calibrated to manage real risk or to manage the discomfort of uncertainty.

> **The approach is: get device standards right, use what exists, and add sophistication as the operational case develops.**

LESSON 2

GET THE "PLUMBING" RIGHT: STANDARDS FIRST, SOLUTIONS FOLLOW

One of the more counterintuitive findings from the study tour was how much Australia has achieved with relatively limited active control of its solar and battery resources. Most rooftop solar is not enrolled in virtual power plants. Most home batteries are not being centrally dispatched. And yet the grid is functioning — and innovating — because the technical foundations are in place to allow active management to grow incrementally when it is needed.

The foundation for this was laid in South Australia. Facing local network hosting capacity constraints that would otherwise have meant refusing new solar connections, SAPN — with funding from the Australian Renewable Energy Agency (ARENA) and drawing on California's Rule 21 — developed flexible exports and, as part of that work, pioneered a communication standard for how inverters talk to network operators. That local innovation was adopted nationally and became CSIP-AUS: the *Common Smart Inverter Profile - Australia*. Under CSIP-AUS, every compliant solar installation has the technical capability for a network operator to communicate with it, even when the device is operating passively or responding to price signals on its own. The standard does not require active management, but it makes active management possible. CSIP-AUS is now mandated for solar installations across the states of South Australia, Victoria, and New South Wales (NSW) and is being introduced in other jurisdictions. The next version of the standard is expected to add battery communication functionality, but that work is still underway.

What SAPN built first with flexible exports was a solution to a distribution problem: too much solar, not enough network capacity or load to absorb it. Later it used the same communication infrastructure to develop the solar backstop, which allows SAPN to curtail inverter output across the board when directed by AEMO to prevent system-wide frequency instability. Once both flexible exports and the solar backstop proved out, the national regulator adopted them for application in other parts of the country. That sequence is worth noting: SAPN acted on a local operational need, built the technical capability to address it, and the national framework followed, once it had developed a proven track record.

The same capability that allowed SAPN to manage export limits and curtail inverters for system security could, in time, support a much broader range of grid services — using home batteries to relieve local distribution constraints, enabling household participation in ancillary service markets, or supporting virtual power plant coordination at scale. That optionality to achieve active orchestration of CERs at scale is currently being explored in a number of trials funded by ARENA, Australia's national renewable energy innovation agency. The Intellihub Demand Flexibility Platform Project is testing smart meter-enabled demand response over 500 MW of aggregated load. The South Australia Energy Masters program is a network-led pilot working with retailers to coordinate smart home appliances and CERs through a home energy management system. And the Market Active Solar trial — set up by SAPN to allow retailers to layer their own CER management offers on top of the network's flexible exports communications channel — is demonstrating how retailers like Engie can participate directly in distribution-level demand management. These are not mature or universal — they are structured experiments designed to find what works before it gets embedded in national rules.

It is also worth noting what Australia has not done. It has not built out enterprise-scale distributed energy resource management systems (DERMS) or a dedicated communications network, nor has it waited for near-universal smart meter coverage before acting. South Australia has managed its solar boom with roughly 50% smart meter penetration. The approach is: get device standards right, use what exists, and add sophistication as the operational case develops.

What this means for U.S. regulators: Australia's approach shows the importance of investing in technical standards early, even if the operational need is not yet urgent — and that investment can be more modest than it may appear. The optionality created by technical standards can be built on tools and communications infrastructure that utilities already have; DERMS and dedicated networks may have a role in time, but they do not need to be the starting point. The value is in creating the capability — the option to act — before it is needed. Also, the standards runway is longer than it looks, and waiting for operational constraints to define standards would mean applying them to CERs and utilities too late. Australia's experience suggests that starting earlier than feels necessary is not over-preparation — it provides options when the pressure arrives.

LESSON 3
CERS: PUT CUSTOMERS FRONT AND CENTER

There is a version of the distributed energy future that is primarily a technical story: inverters, standards, dispatch signals, flexible exports, optimization algorithms. Australia's experience suggests that version is incomplete. Bringing resources on requires a value proposition compelling enough for consumers to act, and unlocking their full value for the grid requires consumers to allow their assets to be part of an actively managed system. Neither happens without real attention to customer benefits and needs.

Australia's solar boom was driven almost entirely by economics. Consumers installed panels because they were cheap and grid-supplied electricity was comparatively expensive. But the next layer of value — getting those solar systems and batteries to respond to grid needs, participate in markets, or allow network control — requires ongoing consumer consent. Australia's experience suggests that consumer consent is earned through simplicity, fairness, and trust in the institutions delivering the message — and the country is still working out how to get all three right.

This is why the shift from *distributed energy resources to consumer energy resources* matters. It is an acknowledgment that these assets sit in people's homes and backyards, that the people who own them have their own priorities, and that the grid can only access their value with those people's ongoing participation. The term *social license* — heard repeatedly on the study tour, and treated by Australian practitioners as a serious operational and business concept — captures this precisely: the right to operate is not granted by a commission order, it is earned in the community and maintained over time. What struck study tour participants was how explicitly Australian network providers and energy retailers talked about social license as something that had to be actively cultivated.

ARENA is funding multiple parallel consumer engagement trials precisely because there is no universal answer. Different customers — across income levels, housing types, and communities — respond differently to different offers and messengers, as the Energy Masters trial is working to test. The goal is to find what works for whom, rather than impose a single model.

At the same time, the equity dimension is real and unresolved. The AEMC is actively reviewing how fixed network costs should be recovered as the solar-heavy customer base grows. The customers who have benefited most from Australia's CER boom are homeowners with roof access and capital to invest. Renters, apartment dwellers, and lower-income households have largely been left out, and in early trials of distributed, front-of-meter batteries (sometimes called "community batteries") there is the perception that the benefits have often stayed with the DNSPs and retailers, rather than supporting communities directly.

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That equity issue connects to a broader affordability tension that study tour participants noted. Australia's relatively high retail electricity prices were actually a driver of solar adoption: expensive grid power made cheap rooftop solar very compelling, giving customers a tool to manage their own bills even as rates stayed high. That dynamic is different from the context in many U.S. states, where the affordability conversation tends to focus on trying to keep rates low overall rather than giving customers the means to reduce the impact of high rates on their bills. The Australian experience suggests a reframe worth considering: the question may not only be how to keep electricity affordable, but how to give customers — including those without access to rooftops or capital — the tools to control their own energy costs.

What this means for U.S. regulators: Bringing distributed resources on at scale and unlocking their full value for the grid are interrelated goals, and both have a consumer dimension that technical standards alone cannot address. The consumer relationship needs a solid and straightforward value proposition delivered through trusted channels. Regulators who want to unlock the value of distributed resources need to ask what their utilities, competitive suppliers, and others involved in the customer relationship are doing to build trust, simplify participation, and benefit customers, including those who have not yet engaged. Regulators may wish to ask whether the regulatory framework is designed such that this type of customer focus is a basic expectation that will drive a virtuous cycle of increased trust, customer participation, and value creation.

LESSON 4

REGULATOR BE NIMBLE: HIGH-LEVEL INCENTIVES CREATE ROOM TO MOVE

U.S. regulators who spend significant time on rate cases — reviewing line-by-line cost filings, debating capital structure, adjudicating disputes about individual projects or programs — will find Australia's regulatory model disorienting. The AER — Australia's ratemaking body — conducts its comprehensive reviews of DNSPs once every five years and strictly limits mid-cycle adjustments, relying on the overall incentive framework to drive efficiencies between reviews.

The AEMC — Australia's energy rulemaker — operates primarily by evaluating rule change requests submitted by utilities, consumer groups, governments, or other stakeholders. It assesses proposals against the long-term interests of consumers and makes a determination on policy changes. Even on complex subjects, this process often runs in six months or less — faster than many U.S. commissions complete a routine rate case.

The AER implements the policy framework set by the AEMC through its five-year regulatory reviews. DNSPs propose their expected costs for the period; the AER sets revenue allowances for both operating costs and capital expenditure, attaches performance incentives worth two to five percent of revenue tied to reliability metrics (SAIDI and SAIFI), and applies a shared-savings mechanism so that both the network and consumers benefit when costs come in below cap. The five-year structure means utilities are not returning to regulators for approval of course changes, except when truly material. This regulatory structure focuses on managing outcomes, as opposed to managing inputs.

Host organizations visited on the tour expressed a consistent preference for fewer, macro-level incentives. Stacking multiple overlapping mechanisms — each with its own reporting and compliance burden — was seen as a drag on the innovation the incentives were designed to encourage. Simpler metrics, higher stakes, and less administrative overhead were preferred.

When new ideas arise that challenge existing rules, the AER has space to allow experiments to happen. When an energy sector participant wants to try something that would conflict with AEMC's rules or AER's guidelines, it can apply to AER for a time-limited "regulatory sandbox" or a ring-fencing waiver. These mechanisms create formal, bounded pathways for experimentation that do not require changing the underlying rules before knowing whether the experiment will work. And they create an evidence base: if the experiment succeeds, it can inform rule changes — though the ultimate outcome may be to catalyze competitive market solutions rather than expanding the regulated entity's scope.

The NSW Distribution System Plan offers an example of what this posture looks like in practice — not a formal sandbox or waiver, but a voluntary planning exercise that reflects the same underlying orientation and points to outcomes that could stretch current roles and responsibilities. When Australia's three New South Wales DNSPs — Ausgrid, Endeavour Energy, and Essential Energy — recognized that AEMO's national Integrated System Plan (ISP) was treating distribution networks as passive load sinks rather than active contributors, they chose not to wait for a regulatory mandate or funding to address the gap in the ISP. Instead, they voluntarily produced their own joint plan, simultaneously pushing AEMO to expand its national modelling framework and supplying the distribution-level data that framework needed (see Box 2).

The result was a collaborative gap-filling exercise — networks and system operator responding to the same blind spot from their respective sides, neither waiting for the other. Notably, some of what the DSP calls for — including DNSP ownership of EV charging infrastructure and distributed, front-of-meter or "community" batteries — is already being tested under ring-fencing waivers. Whether those experiments lead to permanent expansions of DNSP roles, or instead catalyze competitive market offerings, remains an open question.

SAPN Network Innovation Centre. PHOTO CREDIT | BRYN WILLIAMS

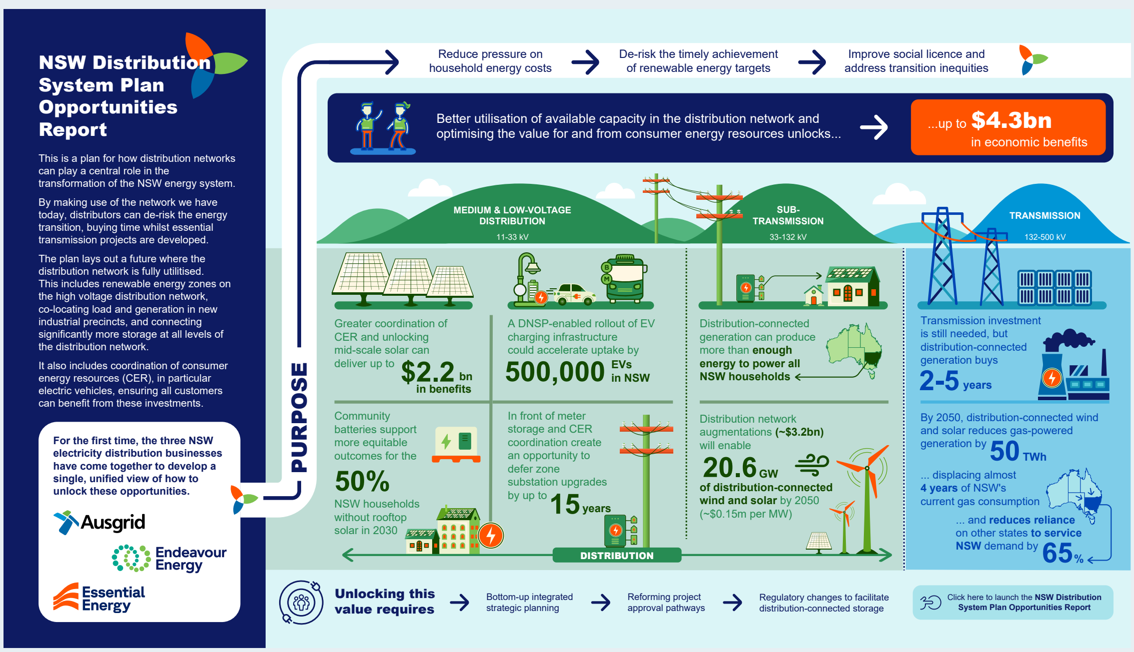
THE NSW DISTRIBUTION SYSTEM PLAN — THE "MISSING MIDDLE" STEPS FORWARD

How three network operators mapped the grid opportunity that the national plan could not see

Australia's Integrated System Plan (ISP) — the national infrastructure roadmap published every two years by AEMO — is widely regarded as one of the most sophisticated whole-of-system plans anywhere in the world. But with the rise of CERs, it had a structural blind spot: it modelled the transmission network in detail while treating distribution networks largely as passive load sinks. Consumer energy resources showed up in the ISP as aggregate demand forecasts, not as active assets with hosting capacity, flexibility value, and grid services potential.

Australia's three New South Wales distribution networks — Ausgrid, Endeavour Energy, and Essential Energy — saw the same gap from their side of the bulk supply point. Starting with the 2025 ISP inputs process, Ausgrid began formally urging AEMO to strengthen its treatment of distribution networks in the national plan, while simultaneously working with the other two NSW networks to produce a joint **Distribution System Plan (DSP)** that could supply the distribution-level data and analysis the national model needed but couldn't generate itself. The DSP was voluntary — no regulation required it and no special ratemaking set-aside supported it; it was explicitly separate from the AEMC's parallel rulemaking process that may eventually mandate this kind of planning nationally.

The result was a convergent effort: AEMO incorporated distribution network development opportunities into its modelling for the first time in the Draft 2026 ISP, while the NSW DSP provided the granular, distribution-level evidence base that made that incorporation meaningful.



The substance of the NSW DSP makes clear why the gap mattered. Independent modelling showed NSW could unlock between AUS $2 billion and $4.3 billion in value by better utilizing available network capacity and integrating consumer energy resources and other distribution system solutions. Smarter use of existing distribution assets could provide a two-to-five-year buffer to the energy transition timeline — buying time while critical transmission infrastructure is built, and potentially deferring network upgrades by up to 15 years in some areas.

The three NSW DNSPs also jointly published an interactive **Network Hosting Capacity Opportunities Map** on the NSW Government's Spatial Digital Twin platform — a publicly accessible tool showing available generation and load capacity by location, with forecasts to 2035. The map gives developers, regulators, and communities visibility into where the distribution network has room, rather than requiring bilateral data requests to each network provider.

What this means for U.S. regulators: The Australian regulatory framework is not directly transplantable, but design principles are available: U.S. states looking at new or revised regulatory frameworks can prefer high-level metrics over line-by-line review, multi-year rate periods over annual cases, and formal pilot pathways that build evidence for widespread regulatory changes over consensus-before-action. Regulators who can move even partially in this direction — through longer rate cycles that incorporate mid-cycle protections, cleaner performance incentives, or structured pilot frameworks that can lead to broader adoption of beneficial solutions — may get more adaptive behavior from their utilities.

CONCLUSION

U.S. regulators are in a position to decide whether their electricity systems will be ready when distributed energy resources scale. Australia's experience is a preview of the strain that rapid growth can bring, but also what it looks like to respond effectively when the pressure arrives.

The four lessons from the study tour point in the same direction: Regulators and utilities may want to get more comfortable acting on incomplete information and letting operating experience refine needed solutions. Technical standards that enable solutions to scale should be put in place while there is still runway; this can reduce dependency on costly and time-consuming investments, and allow the business case for added investments in grid functionality to become clearer as opportunities grow. The consumer relationship and experience should be treated as a core regulatory concern, not an afterthought. And the regulatory framework can be designed to expect adaptation and leave room for innovation.

None of this requires replicating Australia's model in its entirety. The national regulatory structure, the contestable services framework, the energy-only market design — these may not be importable. What is available is the underlying posture: a willingness to move with urgency, to use existing tools and technologies while building new ones, and to measure success by outcomes rather than process compliance.

The participants who made this trip came back energized — not because Australia has solved the distributed grid problem, but because it is genuinely wrestling with it, at scale, with creativity and speed. The transition to a more distributed, dynamic grid demands innovation, and U.S. regulators are positioned with tools to support it.

KEY TERMS AND ACRONYMS

AEMC	Australian Energy Market Commission. The national body that sets the rules governing Australia's electricity and gas markets.
AEMO	Australian Energy Market Operator. Runs the day-to-day operations of the NEM, procures ancillary services, and publishes the Integrated System Plan.
AER	Australian Energy Regulator. Sets revenue allowances for distribution and transmission networks through five-year regulatory reviews, and enforces the rules set by the AEMC.
ARENA	Australian Renewable Energy Agency. The national renewable energy innovation agency that funds trials and knowledge-sharing projects.
AugEx	Augmentation Expenditure. Capital spending by a network to expand capacity or extend service to new areas.
CER	Consumer Energy Resource. The term increasingly used in Australia in place of DER, reflecting that these assets largely belong to and are operated by consumers.
CSIP-AUS	Common Smart Inverter Profile Australia. The national communication standard that enables network operators to send instructions to compliant solar and battery inverters. Adapted from California's Rule 21 / IEEE 2030.5.
DER	Distributed Energy Resource. The traditional term for resources connected to the distribution grid.
DERMS	Distributed Energy Resource Management System. Enterprise-scale software for centrally monitoring and dispatching distributed energy assets.
DNSP	Distribution Network Service Provider. The regulated entity that owns and operates the local poles-and-wires network delivering electricity to homes and businesses. Known as a distribution utility in the U.S.
DSO	Distribution System Operator. A proposed expanded role that would involve actively managing distributed resources on the local grid, not just passively delivering power.
DSP	Distribution System Plan. A planning document that maps distribution network capacity and opportunities. In this report, refers to the joint plan produced voluntarily by NSW's three DNSPs in 2025.
ISP	Integrated System Plan. AEMO's biennial whole-of-system infrastructure roadmap for the NEM.
MS	Minimum System Load. The lowest level of electricity demand a power system can safely operate at while maintaining frequency stability.
NEM	National Electricity Market. Australia's wholesale electricity market covering the eastern and southern states (Queensland, NSW, Victoria, South Australia, and Tasmania).
RepEx	Replacement Expenditure. Capital spending by a network to replace aging assets at end of life. Reviewed separately from AugEx by the AER.
SAIDI / SAIFI	System Average Interruption Duration Index / System Average Interruption Frequency Index. Reliability metrics used to measure how long customers experience outages and how often they occur.
SAPN	SA Power Networks. South Australia's electricity distribution network service provider, serving approximately 900,000 customers.
VPP	Virtual Power Plant. An aggregation of DERs/CERs coordinated to act as a single dispatchable unit in the wholesale market or for grid services.

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