Date of Hearing: June 24, 2026

ASSEMBLY COMMITTEE ON UTILITIES AND ENERGY
Cottie Petrie-Norris, Chair
SB 913 (Becker) – As Amended June 15, 2026

SENATE VOTE: 39-0

SUBJECT: Resource adequacy: aggregated distributed capacity resources

SUMMARY: Changes the resource adequacy (RA) program requirements to expand the use of, and RA credit allocated to, aggregated distributed energy resources (ADERs). Specifically, **this bill**:

1) Requires the California Public Utilities Commission (CPUC), in coordination with the California Energy Commission (CEC) and the California Independent System Operator (CAISO), on or before June 30, 2027, to enhance existing market-integrated pathways for aggregated distributed capacity resources, as defined, to qualify as RA capacity.

2) Requires this market-enhancement occurs by the CPUC ensuring:

   a. Aggregated distributed capacity resources can count toward local, system, or flexible RA requirements.

   b. Aggregated distributed capacity resources receive full RA credit for their entire capacity, including energy they export to the grid beyond the customer's meter.

   c. Aggregated distributed capacity resources that meet reasonable and standardized technical requirements, as specified, can be settled using device-level data rather than requiring a traditional revenue-grade utility meter at each location.

   d. The CPUC's capacity counting methodologies must be compatible with device-level measurement, credit both load reductions and energy exports at any hour of the day, fully integrate ADERs into existing RA structures, and allow aggregated distributed capacity resources to mix different types of devices and technologies.

   e. Multiple devices can participate behind the same utility meter, including in separate programs simultaneously, as long as the same load reduction or energy export is not compensated twice.

   f. Customer data privacy must be protected consistent with state law, and enrollment processes must follow industry best practices, including those developed for the 2025 Demand Side Grid Support Program, to lower barriers to participation.

   g. Where feasible, capacity determinations must be technology-neutral, based on actual measured performance, and adjusted for weather, so the widest range of devices can qualify. The aggregated distributed capacity resource provider bears responsibility for ensuring it can deliver its promised load reduction or energy supply when called upon.

h. Aggregated distributed capacity resources must be able to participate in the CAISO existing market participation models, as those models may be updated pursuant to the bill.

3) Requires the CPUC to set rules under which customer-sited devices can export energy to the grid as part of an aggregated distributed capacity resource, with the goal of maximizing grid benefits while ensuring that customers on net energy metering or net billing tariffs are not paid twice for the same exported energy (once through the demand response program and again through their retail bill credits).

4) Requires the CPUC to allow load-serving entities (LSEs) – i.e., electrical corporations, electric service providers (ESPs), and community choice aggregators (CCAs) – to include aggregated distributed capacity resources in RA filings and CPUC-ordered procurement. Requires the CPUC to ensure specified program rules to effectuate this inclusion.

5) Requires the CPUC, on or before June 30, 2027, to develop recommendations for changes to the CAISO's proxy demand resource and the DER aggregation participation models to be consistent with the CPUC's requirements for aggregated distributed capacity resources pursuant to these provisions, and to request that the CAISO implement these changes in a new or existing initiative.

6) Defines "aggregated distributed capacity resource" as one or more distributed resources capable of supplying electricity to, or reducing demand on, the electrical distribution system. Explicitly excludes customers participating in a net metering tariff under the first and second net metering rules and fuel cell net metering rules adopted by the CPUC.

7) Makes several findings and declarations concerning the role of DERs to provide capacity value to satisfy RA requirements.

EXISTING LAW:

1) Requires the CAISO, as a nonprofit, public benefit corporation, to conduct its operations consistent with applicable state and federal laws and consistent with the interests of the people of the state. (Public Utilities Code § 345.5)

2) Requires the CAISO to ensure the efficient use and reliable operation of the transmission grid, as provided. (Public Utilities Code § 345)

3) Requires the CPUC, in consultation with the CAISO, to establish RA requirements for all LSEs and requires the CPUC in establishing those requirements to ensure the reliability of electrical service in California. Requires that the RA program achieve specified objectives, including that it establish new or maintain existing demand response products and tariffs, as specified. Defines LSE, for that purpose, as an electrical corporation, ESP, or CCA. (Public Utilities Code § 380)

4) Defines "distributed resources" to mean distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. (Public Utilities Code § 769)

5) Creates the Demand Side Grid Support (DSGS) Program and requires the State Energy Resources Conservation and Development Commission (i.e., the CEC) to implement and administer the program to incentivize dispatchable customer load reduction and backup generation operation as on-call emergency supply and load reduction for the state's electrical grid during extreme events. (Public Resources Code § 25792)

FISCAL EFFECT: According to the Senate Committee on Appropriations, this bill will result in ongoing costs, potentially in the millions of dollars annually in ratepayer funds to pay for the CPUC to implement the bill.

BACKGROUND:

California's RA Program – Following the 2000–2001 California electricity crisis, the Legislature adopted reforms to reduce the risk of capacity shortfalls, reliability events, including rotating shortages, and insufficient procurement of generating capacity. AB 380 (Núñez, Chapter 367, Statutes of 2005) established the state's RA program and added Public Utilities Code Section 380, which directs the CPUC to establish procurement requirements and compliance rules for all LSEs, while the CAISO evaluates system and local reliability needs and determines if procured resources are sufficient to maintain grid reliability.[1]

LSEs – entities that supply electricity to customers – must purchase more power capacity than they expect to need (a "reserve margin") for the busiest time ("peak demand"), so there's always a buffer of extra resources ready if demand spikes or something goes wrong. The RA program is the compliance and enforcement program to ensure this adequate supply is always maintained. LSEs demonstrate compliance through annual and monthly filings, showing that their capacity is deliverable to areas with reliability needs. Resources are compensated for being available to provide electricity when called upon, namely during times of system stress, rather than for the actual production of energy. This is the core concept in the RA program of "deliverability."

RA Requirements and Compliance – The current RA program consists of system, local, and flexible requirements for each month of a compliance year. System requirements are determined for each LSE based on the CEC's electricity demand forecast plus an 18% planning reserve margin established by the CPUC.[2] Local requirements are based on annual studies conducted by the CAISO to ensure sufficient capacity is available in transmission-constrained areas under reliability scenarios, including a one-in-ten-year weather assumption and N-1-1 contingency conditions.[3] Flexible RA requirements are based on an annual study by the CAISO that identifies the largest three-hour ramp in each month and are intended to ensure sufficient flexible capacity is available to run the system reliably.[4]

In October, LSEs must demonstrate that they have procured 90% of their system RA obligations for the five summer months (May-September) of the following year. They must also show 100%

---

[1] Public Utilities Code § 380 (a) (1)
[2] pg. 5, CPUC, "2026 Resource Adequacy and Slice of Day Guide," September 23, 2025, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2026-ra-slice-of-day-filing-guide.pdf
[3] N-1-1 Contingency: A sequence of events consisting of the initial loss of a single generator or transmission component (Primary Contingency), followed by system adjustments, followed by another loss of a single generator, or transmission component (Secondary Contingency).
[4] CPUC; "2026 Resource Adequacy and Slice of Day Guide"; pp. 9 (Table 1); Issued September 23, 2025

of their local requirements, and 90% of their flexible requirements for each month of the compliance year. There is an additional monthly reporting requirement for RA, where LSEs must demonstrate they have procured 100% of their monthly compliance across system and flexible RA obligations.

Slice-of-Day Framework – The CPUC has shifted the RA program away from a monthly peak approach and toward a slice-of-day (SOD) framework that evaluates if sufficient capacity is available in each hour of need**.** In 2021, the CPUC determined that this approach better reflects evolving grid conditions, including increased renewable penetration, shifting load profiles, and the growing role of energy storage.[5] Implementation began in 2023, with 2024 serving as a test year and 2025 as the first compliance year.[6] Under SOD, LSEs must demonstrate they have procured sufficient capacity to meet hourly demand plus a planning reserve margin (approximately 17%)**,** evaluated for each hour of the most stressed day in each month.

RA Compensation – Resources used to meet an LSE's RA requirement are compensated for the ability to call on the resource when needed, known as a "must-offer obligation." A resource that commits to providing RA undertakes the "must-offer obligation" to bid or self-schedule its capacity into the CAISO wholesale market, ensuring capacity is available for system reliability. When generators contract with LSEs to provide RA, they must make their capacity available or face penalties. The actual dispatch of resources to meet load in real-time is performed on an economic basis, with the lowest cost resources committed first. As such, RA resources must be offered into the wholesale market, but they may not be dispatched to serve load if there are less expensive resource bids available (including non-RA resources).

The RA program provides an additional source of revenue beyond just actual energy sales. To qualify to sell RA, a resource type must first be assigned a qualifying capacity (QC) from the CPUC, which represents a resource's maximum capacity eligible to be counted towards meeting its RA. The resource must then register with the CAISO and be tested to determine if it is "deliverable" to load when the transmission system is stressed by high demand. Following the deliverability assessment, each resource is assigned a net qualifying capacity ("NQC") value, which defines the amount of RA that it can sell. For intermittent resources like wind and solar, the NQC value is typically well below the nameplate capacity of the facility. Demand response and energy storage resources are eligible to provide RA value, while energy efficiency is generally subtracted from the load forecast. In the case of behind-the-meter energy storage resources, they do not receive value for their exports to the grid.

DERs in RA – As the volume and variety of DERs has grown – spanning rooftop solar, battery storage, electric vehicles (EVs), smart thermostats, and other load-modifying technologies – stakeholders have increasingly pressed both the CPUC and CAISO to better accommodate these resources in the wholesale market, including by recognizing the full capacity value of behind-the-meter resources and their exported energy. While CAISO tariffs already permit DER aggregations to participate in its markets, the question of full capacity credit for behind-the-meter

---

[5] CPUC, *Decision Requiring Procurement to Address Mid-Term Reliability (2023–2026)*, Decision 21-06-035; Adopted June 24, 2021; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF
[6] CPUC, *Decision Adopting Local Capacity Obligations for 2024–2026, Flexible Capacity Obligations for 2024, and Reform Track Framework*, Decision 23-06-029; Adopted June 29, 2023; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M511/K140/511140071.PDF

resources and aggregations has remained an active and unresolved issue at both the CPUC and CAISO for years.

The CPUC currently has an open proceeding[7] that is examining enhancements to demand response programs, including valuation methodologies, CAISO market integration, and RA credit for these resources. In parallel, CAISO launched its Demand and Distributed Energy Market Integration (DDEMI) Working Group in February 2025[8] to develop or refine participation models and market rules for demand-side and distributed resources, whether participating independently or through managed aggregation. That initiative produced a Discussion Paper on November 26, 2025,[9] which is now helping to shape CAISO's priorities on several issues directly relevant to this bill, including the capacity value of behind-the-meter battery storage exports and aggregated DERs more broadly.

COMMENTS:

1) *Author's Statement.* According to the author, "Californians are struggling with rising electricity bills, and we need to use our grid more intelligently and cost-effectively. Instead of always building expensive new infrastructure to meet just a few peak hours of demand, we should be making better use of the resources we already have in our homes. Millions of Californians already have tools like smart thermostats, home batteries, and electric vehicles that can help support the grid. SB 913 ensures we can use those resources to lower costs, reduce pollution, and improve reliability."

2) *Purpose of Bill.* The author and supporters of this bill argue that behind-the-meter DERs and aggregated resources face structural disadvantages in the RA market, pointing to CPUC and CAISO rules that limit their ability to compete on equal footing with conventional energy resources. They view this bill as necessary to unlock the full grid value of these resources and reduce costs for all customers. Supporters point to the CEC's Demand Side Grid Support (DSGS) Program – which has enrolled 1,000 MW of DERs to reduce customer load during extreme events – as proof of concept, while noting that state budget funding for the program is uncertain going forward. They argue that the continued growth of EVs and battery storage represents significant untapped potential: of California's 2.5 million EVs, only around 25,000 are enrolled in managed charging programs, and devices like smart thermostats and electric panels offer further opportunities to reduce consumption when grid stress peaks. Aggregating these loads, supporters contend, could meaningfully reduce strain on the electric grid during high-demand periods.

   Underlying these arguments is a practical financing concern: without a clear pathway to earn RA credit, and the revenue that comes with it, aggregators and DER providers may struggle to build viable business models around these resources, limiting deployment and participation well below what the grid could otherwise support. By establishing RA credit eligibility for aggregated distributed capacity resources, this bill aims to provide a

---

[7] R. 25-09-004, *Scoping Memo dated February 12, 2026*
[8] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Demand-Distributed-Energy-Market-Integration
[9] https://stakeholdercenter.caiso.com/InitiativeDocuments/Discussion-Paper-Demand-and-Distributed-Energy-Market-Integration-Nov-26-2025.pdf

market-based funding mechanism that does not depend on continued state budget appropriations.

3) *High Specificity.* This bill prescribes with significant specificity what the CPUC and CAISO must do, how they must do it, and by when – directing both to adopt enhancements to existing rules governing capacity value for DERs. The proposed requirements span energy export credit for behind-the-meter battery storage, DER aggregation, multiple device and program enrollments behind a single customer meter, device-level telemetry for settlement, and streamlined customer enrollment processes. While recent amendments limit these provisions to non-NEM resources, the level of prescription raises questions about whether the Legislature should be locking in technical and market design specifics that are more appropriately resolved through the CPUC and CAISO's existing proceedings where tradeoffs with other programs, compensation structures, and market rules can be evaluated deliberatively. Supporters counter that without legislative direction, these proceedings risk producing little meaningful progress.

   Several of the bill's specific requirements, however, warrant scrutiny. The mandate to provide full capacity credit during any hour of the day, for example, does not account for the degree to which these resources can reliably deliver during the hours that matter most to grid reliability, and the specifics of the new RA Slice of Day rules. Extending RA credit without a commensurate showing of actual performance could overstate the contribution of these resources to system RA. Similarly, the authorization of device-level telemetry for settlement in lieu of revenue-grade metering may be technically premature: CAISO's March 2026 Straw Proposal explicitly declined to move from service account-level to device-level registration, noting that no other regional grid operator currently maintains such an approach and that doing so would introduce significant data-sharing challenges with utilities and require fundamental changes to demand response registration systems. Taken together, these provisions reflect a degree of specificity that, while responsive to stakeholder priorities, may prove operationally difficult to implement and could confer benefits to DERs that are not yet fully warranted by demonstrated performance.

4) *Does Device-Level Deliver Grid Benefits?* The bill's authorization of device-level telemetry for settlement purposes raises a more fundamental concern than simply whether the technical capability exists to support it: the meter that matters to the grid is the utility meter, not the device meter. Grid operators and utilities are concerned with net load at the point of interconnection (the home service meter) and device-level measurements, while potentially a sufficient proxy, risk overstating the grid benefit actually delivered.

   When a device is curtailed, such as a home air conditioning unit, occupants can respond in ways that load other devices: an HVAC system may be cycled down during a peak event while the occupant, feeling warm, runs a fan or opens the refrigerator repeatedly. The device meter records the curtailment; the utility meter tells a different story. While the load added by a ceiling fan or refrigerator is modest compared to the HVAC reduction, the point is not that the net benefit disappears — it is that the program, measuring at the device-level, pays for the full curtailment while delivering something less, and at the scale of thousands of enrolled households, that gap between measured device performance and actual grid relief becomes material.

Moreover, device-level measurements can miss load shifting within the home, which may become more pronounced if customers enroll their individual devices in separate demand response programs. For instance, moving an EV charge from 6 pm to midnight looks clean in device-level data, but if other flexible loads were already running at midnight, or get displaced into the pre-peak window, the net grid signal is diminished or reversed. The device did what the individual program asked; the home didn't.

When compensation is tied to a device-level baseline (a counterfactual of what that device would have consumed absent the event), but the home net impact is materially smaller, the program is effectively paying for grid relief that was not fully delivered. At scale, this creates a reliability problem, not merely an accounting one: utilities could end up procuring capacity on paper that does not exist in practice. The degree of masking varies by device type, occupant behavior, and dwelling, but the general principle holds: the program would be measuring the signal closest to the intervention, not the outcome we care about. The more prudent approach may be to settle on whole-home net load change, which is what the grid actually experiences. This bill's preference for device telemetry, without requiring a showing that device-level measurement reliably approximates home grid impact, risks embedding a systematic overestimation of DER capacity into the RA program. *Therefore, the committee recommends amendments to specify the device-level telemetry requirements in the bill are only applicable to the extent the CPUC determines such devices provide an accurate measurement of the load changes the grid experienced. The committee also recommends striking "without the need for a revenue grade meter" in 380.1 (a)(3) to allow the CPUC flexibility in determining whether device-level measurements can sufficiently provide accurate grid response data on their own or as a complement to the meter data.*

5) *Changing Program Rules.* This bill makes a number of core RA program rule changes that raise concern; specifically, the requirement that the eligible DERs receive RA credit for their "full" capacity value and the requirement that the RA counting conventions credit DERs "during any hour of the day." Both of these requirements would compensate DERs much more generously than current RA program rules allow for any other resource type. In the context of CPUC's recently adopted Slice of Day (SOD) RA framework, capacity is counted and procured across distinct time periods that reflect when the grid actually needs reliable capacity, not uniformly across all hours. Mandating that aggregated distributed capacity resources receive full capacity credit regardless of the hour they deliver is not only inconsistent with these existing counting conventions, but would effectively exempt these resources from the same performance-based scrutiny applied to all other RA resources. A behind-the-meter battery that discharges at 2 am, for instance, provides little or no reliability benefit during the evening peak hours that SOD is designed to secure, yet under this bill's framework could receive the same capacity credit as a resource that reliably performs when the grid is under stress. The result would be an inflation of the paper RA contribution of these resources well beyond their actual reliability value. The author notes this is not the intent of these provisions. *The committee recommends striking the use of "full" in 380.1(a)(2) and instead using "qualifying;" and rephrasing the "any hour of the day" clause in 380.1(a)(4) to be "during the specific hour of the day required for RA showings."*

6) *CPUC Flexibility.* The bill's directives to the CPUC – requiring it to allow aggregated distributed capacity resources in RA filings and commission-ordered procurement, and to

ensure procurement requirements provide "reasonable flexibility" to accommodate these resources – are framed less like authorizations and more like mandates. (i.e., the CPUC "shall allow LSEs to include these resources in RA" in 380.1 (c)) While the bill includes language about flexibility and cost-effectiveness, it does not provide the CPUC sufficient discretion to condition aggregated distributed capacity resource eligibility on a demonstrated showing that these resources actually meet the reliability attributes that RA and other CPUC-directed procurement is designed to secure. The CPUC should retain the authority to determine whether a given DER, or class of aggregated DERs, can reliably deliver the capacity it claims before that resource is counted toward an LSE's RA obligation or included in a procurement order. Without that gatekeeping, the bill risks directing the CPUC to accommodate these resources in RA regardless of whether they perform as expected. *The committee therefore recommends amendments to clarify that these aggregated resources are eligible for RA credit and commission-ordered procurement only to the extent the CPUC determines they meet the performance criteria, reliability attributes, or other requirements of the applicable RA program or procurement order.*

7) *Additional Amendments. The committee recommends additional amendments to the bill that strike overstated or speculative findings; rename the resources as aggregated distributed energy, rather than "capacity," resources; and make other technical or clarifying corrections throughout.*

8) *Related Legislation.*

   AB 2266 (Schultz) requires the CPUC, and after January 1, 2030, when setting certain resource procurement obligations for LSEs, to use the same capacity valuation method to assess the reliability contribution of each resource type. Status: pending hearing in the Senate Committee on Appropriations.

   SB 1138 (Padilla) requires the CPUC to allow LSEs to satisfy 25% of their RA requirements by trading energy capacity with other LSEs. Status: pending hearing in the Assembly Committee on Appropriations after passage in this committee on June 10, 2026, on an 18-0 vote.

9) *Prior Legislation.*

   AB 740 (Harabedian, 2025) would have required the CEC, in the next update to the biennial integrated energy policy report after January 1, 2027, and subject to available funding, to adopt a virtual power plant deployment plan. Status: Vetoed.

   AB 44 (Schultz, 2025) would have required the CEC, on or before December 1, 2026, and in consultation with LSEs and resource aggregators, to define and publicize methodologies for load modification protocols by which a LSE may reduce or modify its electrical demand forecast upon aggregated system operation of behind-the-meter load modifying technologies and programmatic measures deemed to reliably reduce or modify the LSE's electrical demand. Status: Vetoed.

   SB 541 (Becker, 2025) would have required the CEC, in consultation with specified entities, to analyze the cost-effectiveness of specific load flexibility programs and other types of load-shifting interventions and identify both the approximate amount of load shifting and the cost-effectiveness of each type of load-shifting intervention in the next update to the biennial integrated energy policy report after January 1, 2027, as provided. Status: Vetoed.

REGISTERED SUPPORT / OPPOSITION:

Support

350 Bay Area Action
Active San Gabriel Valley
Advanced Energy United
Affordable Energy Campaign
Ava Community Energy
Ava Community Energy Authority
Brightline Defense
California Alliance for Community Energy
California Coalition of Large Energy Users
California Efficiency + Demand Management Council
California Environmental Justice Alliance (CEJA) Action
California Solar & Storage Association
CalPIRG
Center for Biological Diversity
Center for Community Energy
Center for Environmental Health
Ceres
Clean Coalition
Cleanearth4kids.org
Climate Action Campaign
Climate Center; the
Climate Health Now Action Fund
Community Environmental Council
Deploy Action
Derapi
Environment California
Environmental Defense Fund
Environmental Protection Information Center
Ev.energy
Friends Committee on Legislation of California
Generac Power Systems INC.
Immaculate Heart Community Environmental Commission
Leap
Local Clean Energy Alliance
Local Government Sustainable Energy Coalition
Nextgen California
Pesticide Action and Agroecology Network
Qcells
Reclaim Our Power: Utility Justice Campaign
Renew Home
San Francisco Bay Physicians for Social Responsibility

San Jose Clean Energy
Santa Cruz Climate Action Network
Sierra Club California
Silicon Valley Youth Climate Action
Solar United Neighbors Action
Sunrun
Tesla INC.
The Climate Center
The Climate Reality Project, Los Angeles Chapter
The Climate Reality Project, San Fernando Valley CA Chapter
The Energy Coalition
Uniting the Central Coast for Action
Usgbc California
Voltus, INC.
Vote Solar

Support If Amended

350 Humboldt
Climate Action California

Oppose

Coalition of California Utility Employees
Independent Energy Producers Association

Oppose Unless Amended

Pacific Gas and Electric Company

Analysis Prepared by: Laura Shybut / U. & E. / (916) 319-2083