18 August 2026

Report: Calif. should simplify programs to tap more flexible load

A new GridLab report urges California electricity policymakers to "consolidate" and "standardize" the state's myriad flexible load programs in order to expand the pool of participants, capture new capabilities and better ensure resources are paid for measurable performance rather than just promising to be available.

Co-authored by E3 and Kevala, Unlocking California's Flexible Load: A Durable Blueprint for Affordability and Reliability contends the state faces the "dual challenge" of sharply rising electricity rates and an increasing reliance on variable renewable resources whose supply characteristics move reliability risk from predictable peak hours in the summer to unpredictable intervals throughout the year.

"Containing rate increases requires optimizing every available cost-effective tool. Flexible load can be one of those tools," the report's authors say, adding that "California now possesses an unprecedented base of controllable resources — including millions of electric vehicles, all-electric buildings and distributed battery storage — that did not exist a decade ago."

With the rise of those resources, the authors note, load flexibility could substitute for "much" of the 31 GW of utility-scale storage the state is planning to procure over the next 10 years. "Enrolling just 10% of the 9.7 million light-duty EVs the [California Energy Commission] projects with vehicle-to-grid (V2G) could supply 30% of the cumulative utility-scale storage procurement target for 2036, if V2G resources can be accredited and operated on a comparable basis with grid-scale storage," they write.

The authors contend California's flexible load programs historically have "underdelivered" because of four "recurring flaws":

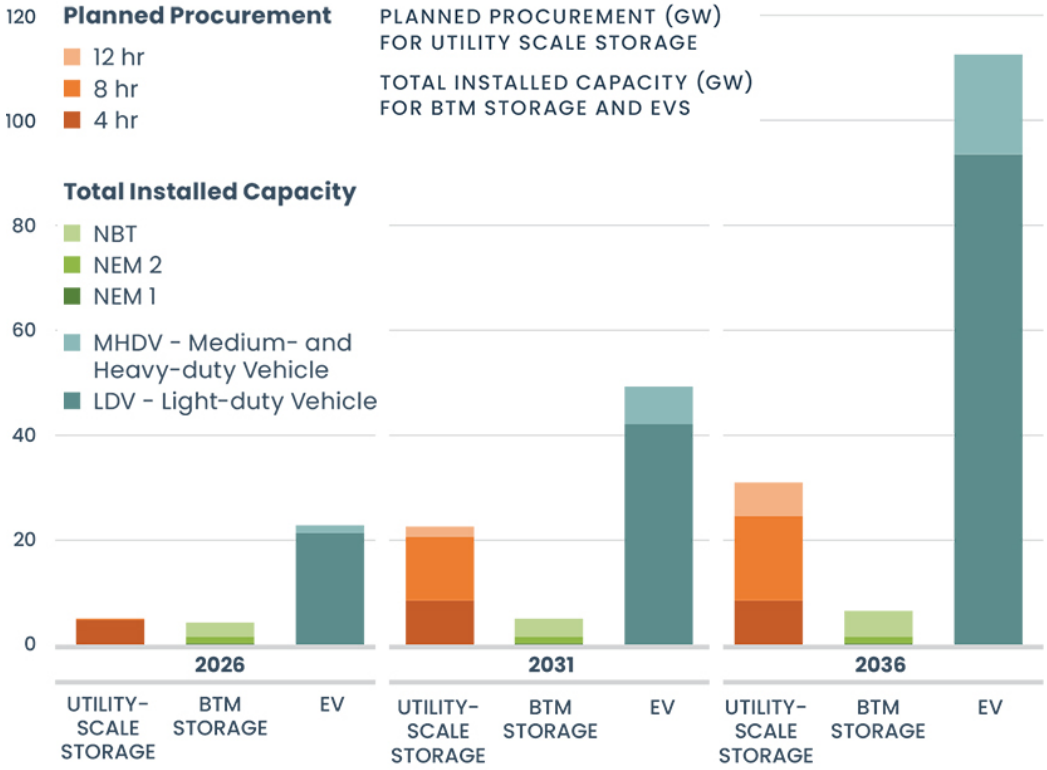
Compensating participants for enrollment "rather than enforcing delivery when called upon with regular testing and verification of performance." Relying on "inaccurate" or "gameable" participant baselines for electricity use. Requiring residential devices and demand response aggregations to submit to program rules that were designed for central power plants. Bypassing needed "core reforms" to existing programs and instead adding new, overlapping emergency programs that increase complexity for potential participants that fail to resolve double-counting of resources.

"California's demand-side programs exhibit a recurring pattern: Programs are initially designed with generous compensation to promote adoption, that compensation becomes embedded in customer expectations, political constituencies form around it, and reform becomes extremely difficult even after the original rationale no longer holds," the authors say. "Rather than repairing the structural weaknesses each iteration exposed, policymakers and utilities responded to the next grid need by layering on new programs."

The legacy of the state's net energy metering (NEM) program for rooftop solar is particularly problematic, according to the authors, because its structure of crediting on-site consumption and exports to the grid at the retail rate (rather than at an avoided-cost rate) is estimated to have increased nonparticipant electricity bills by $7 billion/year by the end of 2024.

The California Public Utilities Commission's 2022 adoption of the net billing tariff (NBT), which reduced export compensation for NEM participants, has reduced the cost-shift, but the NEM retail rate "has proven stubbornly difficult to reform, as the status quo is supported by incumbents to maintain compensation levels that business models and customer expectations were built on," the report says. The upshot is persistence of a program that includes no performance standards and that compensates at a retail rate that "far exceeds the grid value provided by rooftop solar."

Another persistent problem is the state's history of "layering on" new flexible load programs rather than "repairing the structural weaknesses each iteration exposed. This history, most prominently exemplified by NEM/NBT, has made regulators understandably cautious about approving new flexible load compensation structures that will create new constituencies to lobby for continuation even in the face of clear evidence of poor performance or overpayment that shifts costs to other customers," the authors write. "Once a new program is established and embedded in customer and aggregator expectations, it can become difficult to reform or replace."



The report points to the complexity stemming from the sheer volume of the program, with each California investor-owned utility administering 14 or more programs covering various areas such as storage, demand-side grid support, time-of-use metering, EV chargers and emergency response. "The solution to this historic practice is consolidation and standardization of offerings, along with the discipline and political will to 'solve' new challenges as they emerge through improvements to those consolidated and standardized offerings, not development of new, bespoke programs," the authors contend.

That process should be guided by three "core principles:"

Compensation for flexible load resources should be set far enough below avoided costs or competitive market prices to cover administrative costs and provide grid-related benefits to nonparticipating ratepayers.

Payments to resources should be based on "measured performance rather than enrollment" and be connected to verified impact on load during critical intervals that increase grid costs. Baseline-dependent resources (such as smart thermostats and water heaters) require statistical and control group methods, "which warrants conservative initial crediting subject to upward revision as accuracy is confirmed." Programs should be consolidated into "a small number of well-defined products with open, interoperable standards for enrollment, measurement, dispatch and settlement." The authors argue that system and local resource adequacy "are a natural place to begin with a flexible load program."

"Of the grid values flexible load can serve, it is the largest and most uniform, the most robustly quantifiable, and the one where flexible load, performance adjusted, competes

head-to-head with utility-scale storage, a resource whose cost is already well established. Beginning here builds on the firmest ground; additional grid values can be layered on as they are verified and targeted."

RTO Insider
http://www.rtoinsider.com/

18 August 2026

N.Y. moves to improve distributed energy interconnection

New York has directed electric utilities to submit tariff amendments that improve the interconnection process for new distributed energy generation and storage systems. The Public Service Commission said in a news release that its Aug. 17 order (24-E-0621 and 24-E-0415) is in response to stakeholder concerns, as well as requirements of recent legislation.

But the PSC rejected many of the specific changes requested by an industry group, including a cap on developers' interconnection cost responsibility in excess of utility cost estimates and imposition of performance metrics or earnings adjustments for utilities. The changes are an attempt to refine the application process for new assets rated at 5 MW or less and to boost transparency and certainty about the costs and process of meeting the standard interconnection requirements. The greater goal is to strengthen the market for distributed renewables and increase their deployment.

The order is rooted in the Renewable Action through Project Interconnection and Deployment Act of 2024 and the Accelerate Solar for Affordable Power Act of 2026. Among other things, they directed the PSC to consider adding metrics for the timely interconnection of distributed generation and to study the cost of system upgrades needed to interconnect new distributed energy resources.

The PSC said it found the major investor-owned electric utilities generally completed interconnection cost studies in a timely manner and the actual costs were, on average, similar to or lower than the estimated costs. But it determined the DER interconnection process would benefit from greater transparency, and it directed the utilities to file by Oct. 1 tariff amendments that will include requirements to report on interconnection study timelines and update cost information.

With the order, the PSC adopts some of the recommendations from Department of Public Service (DPS) staff, the utilities and developers in response to issues of cost and timeliness raised in various proceedings. Distributed solar has been a success in New York even as developers of utility-scale solar, wind and storage projects have struggled. New York claims the national title for community solar capacity, for example. Even so, development can be slower and more expensive in New York than in many states.

The trade group representing many of the state's small-scale solar developers, the New York Solar Energy Industries Association (NYSEIA), was among the interconnection working group participants that raised concerns in 2024 about interconnection cost estimates DER developers were receiving and the pace of the interconnection process.

NYSEIA, which in 2025 petitioned for the fixed cost cap, described the order as a starting point. "The commission's action today is a step in the right direction for cost transparency," NYSEIA told RTO Insider, "and we look forward to additional actions to fully implement the Legislature's mandate for utility interconnection reforms that unlock affordable, abundant clean energy.

"Rising utility interconnection costs are a key barrier to cost-effective distributed energy deployment in New York state. Just months ago, the Legislature and the governor took decisive action to address this issue by enacting the Accelerate Solar for Affordable Power (ASAP) Act, which seeks to counteract rising utility interconnection costs by

advancing greater cost transparency and cost certainty, flexible interconnection and proactive planning for distributed energy."

The PSC said in the order that extended timelines seen for interconnection of DERs in New York — which can run 2.75 to 4.5 years — appear to be due to external factors such as local permitting, financing and equipment procurement. "In any event," the PSC wrote, "we reject NYSEIA's assertion that failures in the interconnection process are the cause of excessive delays in project completion."

"Furthermore," it wrote, "NYSEIA's assertion that the [utility cost] estimates are unreliable is not well-founded." But the PSC took interest in NYSEIA's suggestion that developers in some circumstances might benefit from a cost estimate prepared to a higher confidence level than the utilities currently target. It directed utilities to file a proposal for how they would produce such estimates upon request, and how much additional time they would need to prepare them.

The PSC rejected the request to disallow utilities to charge for "indirect costs and overhead" because these are specifically recognized cost components under the standard interconnection requirement process and because NYSEIA stated no reason developers should not be liable for their share. The PSC rejected NYSEIA's request for a 15% cap on developer costs in excess of utility cost estimates because no clear evidence was submitted that this is a significant or consistent problem, and because such a cap could expose utility ratepayers to cost risks.

The PSC rejected the "extensive regulatory process" NYSEIA requested for utility cost matrices, saying it would add several months to the timeline and burden DPS staff and utilities with no clear gain in cost estimate reliability. But the PSC directed utilities to file annual assessments of estimated and actual project costs on a rolling five-year basis and to publish their cost matrices annually. The order is directed at Central Hudson Gas & Electric Corp., Consolidated Edison Company of New York, New York State Electric & Gas Corp., Niagara Mohawk Power Corp. d/b/a National Grid, Orange and Rockland Utilities, and Rochester Gas and Electric Corp.

RTO Insider
http://www.rtoinsider.com/

18 August 2026

Portugal works towards 3 GW battery storage target by 2030

The outlook for storage in Portugal is "positive", according to analysis from the Portuguese Association Of Renewable Energy (APREN), with deployments set to increase in the coming years in order to meet end of decade targets.

Susana Serôdio, APREN's Policy and Market Intelligence Coordinator, told ESS News that deployment of battery storage systems in Portugal will accelerate after starting from a limited base.

The association's latest annual review found Portugal had deployed 20 MW of battery storage by the end of 2025. The country's National Energy and Climate Plan (PNEC 2030) sets a target of 2 GW of battery storage by 2030 but a more recent National Energy Storage Strategy presented by the government has raised the target to 3 GW, before increasing to 4.5 GW by 2040.

The majority of Portugal's installed large-scale storage capacity is pumped-hydro storage, standing at 2.8 GW by the end of last year, according to APREN's statistics. Serôdio said pumped hydro accounted for approximately 8.3% of electricity generation in mainland Portugal last year. The country's National Energy Storage Strategy targets further expansion of the technology, with goals of reaching 3.9 GW of pumped hydro capacity by 2030, before increasing to 5.26 GW by 2040. In January 2025, Portugal awarded 43 storage projects,

representing approximately 500 MW, a share of €100 million ($116 million). Serôdio said these projects are expected to become progressively operational.

She added that Portugal's storage rollout will be supported by two competitive procedures planned for September, alongside plans to develop a capacity market for batteries. The two tenders, one allocating up to 750 MVA of grid capacity to standalone storage facilities, and another allocating up to 300 MVA to new renewable generation projects with co-located storage, represent 1.05 GW of new grid-connected capacity. A tender to expand pumped-hydro storage is also envisaged, Serôdio added, subject to discussions with the European Commission regarding state aid rules.

"The outlook is therefore positive, but progress will depend on the speed of licensing and project delivery, access to the grid and, above all, the creation of sufficiently stable revenue streams," Serôdio told ESS News. "The two announced procedures are fully exposed to market revenues and do not currently include a capacity mechanism remunerating availability, which may create challenges for project bankability."

In January, Chinese battery maker CALB unveiled plans to build a lithium-ion battery factory in Portugal. The company says it is targeting an annual capacity of 15 GWh for the site. The plan has been identified by the Portuguese government as a project of national interest and has obtained special grid access rights.

pv-magazine
http://www.pv-magazine.com/

18 August 2026

Europe's largest solar power project obtains final permit

Rezolv Energy, one of the biggest investors in renewable energy in Romania, has obtained the establishment authorization, the final permit, for the Dama Solar project of 1.24 GW in peak capacity. The facility in the country's northwest would be the largest of its kind in Europe. The Romanian Energy Regulatory Authority (ANRE) has issued the so-called establishment or setup authorization to special purpose vehicle West Power Investments, Profit.ro reported. It is the crucial milestone for Europe's biggest PV project. The project firm, controlled by Rezolv Energy, is responsible for the Dama Solar endeavor, at a site in Arad province near the border with Hungary.

According to previous updates, the photovoltaic facility would have 1.24 GW – or as much as 1.3 GW – in peak capacity, and a a 1.07 GW grid connection. The location of 1,064 hectares is on the territory of the communes of Pilu and Grăniceri.

ANRE issues establishment authorizations when developers prove they have the necessary financing. Earlier, the World Bank Group's International Finance Corp. (IFC) was considering a EUR 107 million loan for the project, the media outlet noted. The developer was hoping that the European Bank for Reconstruction and Development (EBRD) would come on board, too.

The company won state support last year in the form of contracts for difference (CfDs) for a 520 MW segment of the Dama Solar project. At Romania's renewable energy auction, it bid EUR 42.2 per MWh, on a rounded basis, under two equal lots. The documentation included a target commissioning date of September 2028 and the start of commercial operation in September 2030, the article reads. Rezolv Energy has indicated that it may add a battery energy storage system (BESS). Notably, it is the largest beneficiary from government tenders for renewable electricity, with 971.2 MW out of 4.6 GW.

Dama Solar was initiated by Monsson. It later sold it to Rezolv Energy, which operates under infrastructure asset manager Actis, majority-owned by private equity firm General Atlantic. Mubadala Investment Co., a sovereign wealth fund of Abu Dhabi, recently invested EUR 300 million in a joint venture with Actis that runs Rezolv Energy. The photovoltaic

project in Arad is valued at EUR 520 million, compared to previous estimates of EUR 800 million to EUR 1 billion.

Europe's largest PV plant is Witznitz in Germany's east. It has 650 MW in peak capacity. There is also an 850 MW cluster of 17 units in Spain, called Escatrón-Chiprana-Samper Solar Farm. If the Asian part of Turkey is included, Kalyon Karapınar is at the top of the list. It has 1.35 GW in peak capacity and a 1 GW grid connection. Already one of the largest in the world outside China, the solar park is due for expansion into a complex of 1.85 GW in peak capacity.

Of note, Enery is building a 761 MW photovoltaic plant in Ogrezeni, just west of the Romanian capital Bucharest. The company obtained a grid connection approval for 534 MW in 2023. The investment includes a 534 MW battery energy storage system (BESS), with more than 1 GWh in planned capacity. It would currently make it the largest such hybrid facility in Europe, but also in both categories separately.

Balkan Green Energy News
http://balkangreenenergynews.com/

19 August 2026

Canadian clean energy deal could boost exports to U.S.

A major new agreement between the Canadian federal government, Newfoundland and Labrador, and Québec to invest about $70 billion in new hydropower capacity, land-based wind and transmission may provide a boost to Canada's net exports to New England and New York.

The tentative agreement, announced Aug. 17, could support up to 14,000 MW of new clean energy, according to the Canadian federal government. It would replace the 1969 Churchill Falls agreement between Quebec and Newfoundland and Labrador, which gave Hydro-Québec long-term access to the bulk of the power from the Churchill Falls Generating Station at an extremely low, fixed price. The original deal, set to expire in 2041, has been a longstanding source of controversy, which continued even after a memorandum of understanding in 2024 for a new deal.

Announcing the deal, Newfoundland and Labrador Premier Tony Wakeham said the country is "finally turning the page on one of the darkest chapters in our past and replacing both the notorious 1969 Churchill Falls agreement and the 2024 MOU with a better deal for all of us." The new agreement is intended to facilitate major investments in clean energy resources, backed by $10 billion in federal financing. It includes up to a 2,500 MW increase in the capacity of the Churchill Falls dam, a 2,700-MW hydro project on Gull Island, 2,000 MW of land-based wind and associated transmission lines.

It would guarantee Newfoundland and Labrador's ability to send power through Québec to export to other markets without price mark-ups from Hydro-Québec. According to the government of Newfoundland and Labrador, the province will be able to send up to 240 MW to New York via the Champlain Hudson Power Express (CHPE) transmission line and up to 200 MW to New England via New England Clean Energy Connect (NECEC), along with 280 MW of synthetic exports "that will be sold at U.S. and Ontario market-based prices."

For New England and New York, the deal could provide a long-term boost to net imports from Canada. Hydro-Québec's exports to the regions have declined substantially in recent years amid a multiyear drought that began in 2023. While Hydro-Québec maintains that it expects to have enough power to meet its firm contractual obligations associated with the CHPE and NECEC lines, it has scaled back its spot market exports to ensure it has enough stored energy to meet all its needs.

Although New England's net imports from Québec have rebounded since NECEC came online — increasing by about 38% over the first seven months of 2026 relative to the

prior year — they remain well below the historical levels from before the drought. And over the past winter, Hydro-Québec halted deliveries over NECEC during Winter Storm Fern due to supply adequacy concerns within the province. The deal reportedly would give Hydro-Québec access to over 10,000 MW of power, potentially easing the supply crunch that has driven declining market-based exports to the U.S.

A spokesperson for the Massachusetts Executive Office of Energy and Environmental Affairs said the new agreement "is an important opportunity to advance our shared priorities. New affordable hydropower and wind power in Labrador can potentially flow to Massachusetts through the five interconnections to Canada, including the newly built NECEC transmission line." They stressed the state's "proud legacy of strong collaboration with Canada," and noted that Massachusetts and Canadian officials recently met "to identify new areas of collaboration."

A spokesperson for Hydro-Québec said the agreement is "first and foremost about helping meet Québec's long-term energy needs," adding that supply, demand and economic conditions will influence power interchanges between the regions. "Any impacts of the agreement on U.S. markets would therefore be expected to occur through normal market mechanisms rather than through specific procurements tied to these projects," they said, adding that the company expects its transmission connections with the U.S. to become "increasingly bidirectional" over the long term.

Joe LaRusso of the Acadia Center said the agreement appears to complement Hydro-Québec's long-term efforts to add substantial amounts of power capacity within the province. "This is just adding to the store of power Hydro-Québec has to use internally and export," he said, adding that it highlights that "being able to share resources over broader geographies really is the answer to resource adequacy issues in New England, Québec and the broader Northeast region."

RTO Insider
http://www.rtoinsider.com/

21 August 2026

Final caisson installed at 3.5GW Princess Elisabeth Energy Island project

The installation of all 23 caissons for the 3.5GW Princess Elisabeth Energy Island has been completed 45km off the Belgian coast in the North Sea, marking the conclusion of the project's foundation works.

The artificial island is being developed on behalf of Elia Transmission Belgium by the TM EDISON consortium, which comprises Jan De Nul and DEME. It is considered to be a significant step in expanding Belgium's offshore wind capacity and aims to facilitate future energy links with the UK.

Princess Elisabeth Island will connect the second Belgian offshore wind zone and is described as a major component of the country's energy transition efforts. Elia Transmission Belgium CEO Frédéric Dunon said: "Completing the foundation works marks a major step in developing Belgium's offshore energy infrastructure, which plays a crucial role in the energy transition and in strengthening our energy independence."

The completed caisson foundations form the protective outer shell of the island. This phase began in 2024 with the installation of the first caisson and has now concluded, allowing the project to advance to the next stage. In the coming months, work will continue to reclaim land inside the caisson structure with sand.

Installation of cable connections to the mainland is scheduled for 2027 and 2028, while electrical infrastructure works on the island are set to begin in 2029. The project is scheduled for completion in 2031, in line with recently confirmed legislation.

The project's timeline enabled Elia to qualify for a €99m ($115m) subsidy provided by the EU for this phase, highlighting the priority placed on European energy independence and cross-border exchange.

Throughout construction, the consortium implemented a nature-inclusive design. Each caisson measures approximately 58m in length, 28m in width, and between 23m and 32m in height, weighing around 22,000t. The caissons were constructed in Vlissingen, with around 300 workers engaged daily, and were then transported and installed at sea.

Elia's artificial island will serve as a hub for transmitting renewable energy from offshore wind farms to Belgium's high-voltage onshore grid and as a junction for planned connections with the British and Danish networks. The six-hectare island will ultimately be linked to the mainland by undersea high-voltage cables with a combined length of 165km and a capacity of 220kV each. The final use and environmental role of the structure after its expected service life is under consideration.

NS Energy
http://www.nsenergybusiness.com/

21 August 2026

Magyar: Hungarian nuclear plant Paks to return to regular operation

Hungary's emergency engineering works and the forecasted rise of the Danube water level are allowing the country's sole nuclear power plant Paks to restart the six idle turbines of the three reactors that had to be shut down. Prime Minister Péter Magyar said the facility would be able to work at full capacity on August 28 at the latest. It was literally inches away from going offline for the first time. But downstream on Europe's second-largest river, Bulgaria's Kozloduy is reducing capacity utilization for the first time.

Halting entirely the operation of the Paks nuclear power plant would have incurred monthly expenses of HUF 50 billion (EUR 137 million), Hungarian Prime Minister Péter Magyar pointed out at the site. The worst scenario was avoided with emergency engineering works and the release of water through the Ráckeve lock system from the other arm of the Danube. The government has sunk two rock-filled barges as a temporary solution for raising the water level near the intake pipes of Hungary's only nuclear plant. At the same time, it is building an underwater weir or sill, a barrier in the bed of the river.

Similar interventions earlier failed to prevent the forced shutdown of neighboring Romania's Cernavodă nuclear plant downstream on the Danube. Bulgarian Kozloduy, consisting of two equal reactors with 2 GW overall, is now forced to slash the capacity utilization of unit 5 by 120 MW. It is the first reduction in the facility's history caused by extreme weather conditions. Built more than half a century ago, it is operated by state-owned Bulgarian Energy Holding (BEH).

The Ministry of Energy said the forecast indicates a further decline in the Danube. Krško, the only other operational nuclear power plant in the region that Balkan Green Energy News tracks, has bounced back to 100% of capacity utilization. The facility in Slovenia, on the Sava river, is shared with Croatia.

Paks, run by state-owned MVM, has 2 GW. It consists of four reactors, each with two turbines. At the most critical point, only one turbine remained in operation. It was essential for the energy required to get the other reactors back on the grid. River water is necessary for cooling the reactors. Both turbines of the same unit are currently working. The Danube in Hungary is forecasted to begin rising a little in a few days.

Magyar said the gradual restart of the remaining three reactors is beginning by the end of the week. Paks is expected to generate power at full capacity on August 28 at the latest, he added. The interventions helped bring the water level at the location up by 15 to 20 centimeters, the prime minister stressed and praised the coordinated efforts on the

national level. Magyar said 326 companies and individuals have offered knowhow, transportation and other kinds of assistance. They committed 200,000 tons of rock, lowering significantly the costs from the estimated HUF 6.2 billion, he revealed.

Balkan Green Energy News
http://balkangreenenergynews.com/

21 August 2026

Saudi Power Procurement signs four BESS agreements worth $1.16bn

The Saudi Power Procurement Company, also known as the Principal Buyer, has signed four storage service agreements for battery energy storage system (BESS) projects.

The projects will provide a total capacity of 2GW with four-hour storage with a planned investment of more than $1.16bn (SR4.35bn). The agreements were signed in the presence of Abdulaziz bin Salman bin Abdulaziz, Minister of Energy, Minister of Industry and Mineral Resources, and chairman of the Saudi Power Procurement Company's Board of Managers.

The Ministry of Energy is supervising the initiative. This first group of projects form part of Saudi Arabia's strategy to enhance the reliability and efficiency of its electricity generation infrastructure.

They are being developed as part of the build-own-operate model and are aligned with ongoing efforts to integrate more renewable energy and storage into the national grid, targeting an electricity generation mix with around 50% renewable energy by 2030. The initial BESS projects comprise the Al Muwyah BESS Independent Storage Provider (ISP) and Haden BESS ISP in the Makkah region, and the Al Kahafa BESS ISP in the Hail region.

Each site will deliver 500MW of storage for four hours. These three projects have been assigned to a consortium of Saudi Energy, ACWA and the Al Sharif Contracting and Commercial Development Company. Meanwhile, the Al Khushaybi BESS ISP in the Qassim region, with the same capacity of 500MW and four hours of storage duration, has been awarded to a consortium consisting of ENGIE and Haji Abdullah Alireza.

The Principal Buyer will oversee pre-development studies and the tendering of power generation and storage projects, and is responsible for signing power purchase and storage service agreements with developer groups.

Power Technology
http://www.power-technology.com/

25 August 2026

Indonesia's Prabowo launches 14 solar power projects

Indonesian President Prabowo Subianto inaugurated 14 solar power plant projects on Tuesday with a combined capacity of 5.3 gigawatts, part of the country's goal to add 100 GW of new solar capacity by 2029 and reduce its dependence on climate-warming fossil fuels.

Here are some details:

- The Reuters Power Up newsletter by columnist Ron Bousso provides everything you need to know about the global energy industry. Sign up here.
- Of the 14 projects, two are already in operation, with six in the construction phase and another six to be offered to investors.
- Total investment in the 14 projects is estimated at 135 trillion rupiah ($7.62 billion), said senior energy ministry official Eniya Listiani Dewi.
- The government's target to build a total of 100 GW of solar power from 2026 to 2029 is estimated to require 1,140 trillion rupiah in investment.

- The planned solar farms are estimated to slash electricity costs by 73.9 trillion rupiah annually by reducing production costs.
- The government aims to shut down 13 GW of diesel-fired power and replace it with renewable energy.

Reuters
http://www.reuters.com/

27 August 2026

Trump declares emergency, moves to block some foreign-made equipment from grid

President Donald Trump on Wednesday signed an executive order preparing to block utilities from connecting some foreign-made equipment to the bulk power system, including transformers, batteries, inverters and associated software and digital products.

The order also contemplates the replacement of already-installed equipment, allowing the Secretary of Energy to "impose conditions on the continued use, operation, maintenance, servicing, or updating of foreign manufactured or operated bulk-power system electric equipment acquired or installed before the date of this order."

The EO "focuses on transactions involving foreign nationals that pose an undue risk of sabotage, unauthorized access, or other disruption," the White House said in a fact sheet, and is aimed non-distribution level equipment. It directs the Secretary of Energy to develop rules within 120 days to implement the order.

The U.S. faces an "extraordinary foreign threat involving bulk-power systems produced abroad that may present national security vulnerabilities," the White House said. "The rapid growth of advanced manufacturing, data centers, artificial intelligence, and defense production has increased the Nation's dependence on abundant, reliable electricity and magnified the consequences of a successful attack."

Utilities are committed to working with DOE "on the implementation of [the] order to ensure that we can maintain the reliability and affordability of electricity across the country," Edison Electric Institute spokesperson Dani Marx said to Utility Dive in an email. The group represents investor-owned power companies and last year it estimated U.S. electric utilities would invest $1.1 trillion in the 2025-2029 period, a rapid increase in capital expenditures to meet rising demand. Capital expenditures from 2015 to 2024 totaled $1.3 trillion, the trade group noted.

According to the International Energy Agency, China accounts for 80% or more of the world's production of certain grid equipment, including lithium-ion battery cells and some solar components. Manufacturers of grid equipment say they are still digesting the order and will likely need clarification on several aspects.

"We've made a lot of progress on ensuring robust supply chains domestically and with our partners," Bridget Bartol, the head of industry and regulatory affairs at the National Electric Manufacturers Association, told Utility Dive.

She said Trump's Wednesday order builds off of 2020 Executive Order 13920, which focused on large power transformers from China, adding, "I see this as kind of an update and expansion." But Bartol warned there is the potential for confusion in the markets as a result of the order, "and we want to make sure that we continue to engage with the administration." Software, in particular, may "raise a lot of questions around what does it mean to be designed and developed by a covered foreign entity," she said, noting that the order does not call out particular countries. "There's a need for a lot more clarity" around the covered entity concerns, Bartol said. "I think there's going to be a lot of dialog between the industry and the administration."

Utility Dive
http://www.utilitydive.com/

27 August 2026

Market Monitor: data center load made up 9% of PJM wholesale costs so far in 2026

Existing and forecast data center load made up 9%, or $10.48/MWh, of the wholesale price of power in the PJM Interconnection this year through July, according to the grid operator's independent market monitor.

That cost came via PJM's capacity market, and doesn't include data center-related increases in the price of electricity or transmission, Monitoring Analytics said in its 2026 first-half state of the market report released earlier this month. In PJM's last four capacity auctions, existing and forecast data center load growth resulted in a combined total increase in capacity market revenues of $29.4 billion, according to the report. "This total will continue to grow until the issues associated with the addition of large data center loads are addressed," the market monitor said.

In the first seven months this year, the total cost of wholesale power surged 46% to $116.53/MWh, or $56.7 billion, up from $79.57/MWh, or $38 billion, in the same period last year, driven by jumps in energy and capacity costs, according to a presentation by the market monitor on Monday to PJM's Members Committee.

In the first seven months this year, average peak load increased by 1.7%, or 1,721 MWh; average off-peak load increased by 2.6%, or 2,281 MWh; and real-time hourly average load grew by 2.2%, or 2,061 MWh, according to the presentation. So far this year, wind farms produced 4.5% of all electricity in PJM and solar facilities produced 3.5%, up from 3.7% and 2.9% from last year, respectively.

PJM has about 13 GW of wind on its system, with a 34.2% capacity factor in the first half of this year, according to the first half report. It has 16.3 GW of solar, with a 21.4% capacity factor in the first six months this year. PJM also had 57 GW of gas-fired, combined cycle units, 37.7 GW of coal-fired generation, 33.5 GW of nuclear capacity and 7.6 GW of hydro units, according to the report.

Utility Dive
http://www.utilitydive.com/

27 August 2026

MISO finds higher load loss risks as it launches South Long-range Tx Plan

MISO South's network of load pockets has not been operating to the one-day-in-10-years reliability standard and could face more capacity shortcomings by 2030, despite utilities' generation additions and transmission upgrades.

That's the crux of MISO's recently conducted load pocket risk assessment, the first step in the grid operator's quest to draw up a long-range transmission plan for MISO South. The load pocket assessment is set to feed into the MISO South long-range transmission plan, dictating planning assumptions and ultimately shaping potential projects.

MISO analyzed its four major South load pockets — Western and Southeast Texas (SETEX) in southeastern Texas, and Amite South and Downstream of Gypsy in southeastern Louisiana — in the 2025/26 planning year. It found each load pocket carried elevated risk beyond the industry's 0.1 day/year planning standard, though MISO's Local Resource Zone 9 (covering Louisiana and southeastern Texas) on the whole did better than the one-day-in-10-years benchmark.

MISO said it expects its South region will benefit from already planned generation additions and transmission upgrades, but it noted that "certain pockets may continue to see tighter margins through 2030." The RTO found Amite South had a 0.4-1.1 day/year loss of load risk; Downstream of Gypsy had a 0.3-0.7 day/year risk; SETEX had a 0.5-0.8 day/year risk; and Western had 0.3-0.6 day/year risk over the 2025/26 planning year. MISO said the

heightened risks translate into capacity shortfalls over the 2025/26 winter season. Amite South had the largest retroactive shortcoming at 914 MW, SETEX came up short by 560 MW, Downstream of Gypsy needed 490 MW and Western was short by 289 MW. Most of the load pockets are positioned to solve their capacity shortfalls with planned generation and transmission investments.

MISO said while those infrastructure developments will improve the load pocket risk picture by 2030, some exceptions remain, namely a forecast 748-MW shortage in spring 2030 in Amite South and a 134-MW shortfall in spring 2030 and a 21-GW deficit in fall 2030 in Downstream of Gypsy. MISO said the load pockets' unique geography, import limitations and strong reliance on local generation can produce diminished reliability statistics than those found in the rest of the footprint.

Discussing results at an Aug. 26 Planning Advisory Committee meeting, MISO's Beibei Li said the assessment signaled that MISO South's load pockets in southern Louisiana and southeastern Texas are more sensitive than the overall region to generation outages. Li said intense weather events like 2021's Winter Storm Uri and 2020's Hurricane Laura have shown MISO planners that reliability risks can be "more acute than the systemwide picture suggests." She said the South load pockets have "different characteristics compared to how the rest of system is behaving during stress conditions."

MISO isolated load pocket operations and examined them "under more realistic system conditions" as part of the study, Li said, and found that they "can run tighter under certain operating conditions." Southern Renewable Energy Association's Andy Kowalczyk asked if MISO incorporated all the large loads trying to get service in MISO South by 2030 in its assessment.

Li said MISO examined only large load projects that have been publicly approved. She said MISO will take load growth and changing operating conditions into account to see if some risks are "more sustained." Li said MISO's load pocket assessment findings aren't meant to replace the broader long-range transmission studies MISO plans to conduct but will "complement them by examining each of the major load pockets individually." Li said MISO will work its risk findings into power flow modeling. MISO previously said staff and stakeholders will continue discussion on issues within Louisiana and southeastern Texas load pockets into 2027. MISO has committed to exploring transmission and generation solutions in the inaugural MISO South long-range transmission plan. (See MISO to Include Southeastern Texas in South Long-range Tx Planning.)

MISO has issued near-daily load pocket advisories for the four load pockets over summer 2026. It similarly issued numerous load pocket advisories over the spring. The grid operator sends out load pocket advisories when it foresees the potential for at least 100 MW

of unserved load due to transmission constraints that are expected to persist for hours. Mississippi Public Service Commission consultant Bill Booth has pointed out that MISO has yet to direct further action after issuing a load pocket advisory since it began using them in May 2025 following a transmission emergency that caused load shedding in New Orleans.

"The last thing you want to do is issue false warnings and false alerts that get people worked up about something that ends up being nothing," Booth said at MISO's May 2026 Market Subcommittee meeting. "All you're doing is accumulating a bunch of alerts that seem to be not very relevant. I think it's kind of important not to send out alerts that don't result in any actions or require any actions." MISO's Jason Howard said the load pocket alerts are akin to MISO's capacity advisories. "We have a process, a procedure that we follow," Howard said. "We have pretty strict guidelines when these things are triggered that provides some consistency."

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