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Utilizing Noncoincident Needs to Site Data Centers with Solar+Storage at Existing Gas Plants

Emilia Chojkiewicz, Aneesha Manocha, Umed Paliwal,
Duncan Callaway, Amol Phadke

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Utilizing noncoincident needs to site data centers with solar+storage at existing gas plants

Authors: Emilia Chojkiewicz[1,2], Aneesha Manocha[1,2,3], Umed Paliwal[2], Duncan Callaway[1,3], Amol Phadke[2*]

Affiliations:

[1]Energy and Resources Group, University of California, Berkeley
[2]Goldman School of Public Policy, University of California, Berkeley
[3]Electrical Engineering & Computer Science, University of California, Berkeley
[*]Corresponding author. Email: aaphadke@berkeley.edu

Abstract

Data centers and large electricity loads are power hungry, raising concerns about higher electricity costs, increased emissions, and reliability risks. We show that co-locating solar+storage systems with underutilized natural gas plants offers a practical, near-term pathway for reliable, low-cost industrial power. Using eight years of hourly weather data, we co-optimize load and hybrid solar+storage+gas configurations at 68 existing plants near data center developments, meeting over 95% of demand with solar+storage. Across these sites, levelized costs range from $60-138/MWh, competitive with data centers' recent contract prices for 24/7 clean power. Conflict analysis indicates minimal overlap between solar+storage backup needs and grid stress across most regions of the United States today, allowing gas units to provide dual roles: facilitating large load integration while supporting grid reliability. By optimizing existing infrastructure, this approach offers a scalable pathway to serve large loads, though realizing these benefits will require careful coordination amongst stakeholders.

Main

The electricity sector faces rapid demand growth, driven largely by the expansion of data centers. Although the magnitude, timing, and geographic distribution of this growth remain uncertain, recent projections indicate that total electricity use in the United States (U.S.) will increase by 32% while national peak demand could rise by 20% (166 GW) by 2030, with data centers responsible for 55% (90 GW) of this increase (Grid Strategies, 2025). Planned capacity additions are insufficient to meet this trajectory, raising capacity prices alongside risks of supply shortfalls (WECC, 2024; NERC, 2024; Sercy and Reed, 2025). Efforts by both utilities and technology companies to secure power are constrained by generation interconnection queues that exceed five years in most regions, escalating network upgrade costs, and multiyear procurement timelines for critical equipment such as transformers (Rand et al., 2024; Gorman et al., 2025; NIAC, 2024). Expansion of natural gas capacity is similarly limited by turbine delivery dates extending to 2030-2031 and new plant costs surpassing $2,000/kW - nearly double those of a few years ago (GridLab, 2025). Meanwhile, other strategies being pursued by technology companies such as long-term power purchase agreements (PPAs), acquisition of legacy assets, or utility partnerships for bespoke tariffs may increase reliability and economic risks for ratepayers; investment in emerging clean firm technologies like enhanced geothermal or Small Modular Reactors (SMRs) faces high capital costs and are not yet commercially available at scale. Together, these constraints intensify concerns that rapid load growth not matched by commensurate and timely capacity additions - particularly when new large loads are not required to directly procure or finance new firm capacity - will heighten competition for scarce grid capacity, strain grid reliability, raise electricity bills, and undermine U.S. economic competitiveness.

One promising approach is to co-locate large loads with new solar+storage projects at existing gas plants for backup (Engel et al., 2025). A key advantage of this approach is the speed to power: surplus interconnection service enables the fast-tracked addition of new generation and/or storage capacity at existing points of interconnection, bypassing the costs and delays of conventional grid connection (Gabel, 2024; Mattioda et al., 2024; Farmer and Silverman, 2025). Prior work indicates substantial technical potential: existing fossil plants could viably host up to 597 GW of new wind and solar capacity by 2030 (Chojkiewicz et al., 2025). This is particularly beneficial for data centers, which cite grid access, power cost, and renewable availability as the primary factors shaping data center development (BNEF, 2025). While existing literature on data centers has analyzed environmental impacts (Ristic et al., 2015; Mytton, 2021; Siddik et al., 2021; Lei et al., 2023; Shehabi et al., 2024) and general siting considerations (Daim et al., 2011; Covas et al., 2012; Abdennadher et al., 2022; Arzumanyan et al., 2025; Fang & Greenstein, 2025), considerably less attention has been paid to near-term implications of accommodating new large loads, particularly for mitigating reliability risks during periods of peak demand. Recent work (Norris et al., 2025) and policy initiatives (DOE, 2025) highlight operational flexibility as one potential solution, but its near-term provision remains uncertain due to workload constraints, weak market incentives, and limited empirical evidence at scale (Kirchstetter et al., 2025).

Motivated by these gaps, our work extends Engel et al.'s analysis in several crucial ways. Specifically, we center our research on existing gas plants with active commercial data center interest, adding realism by incorporating critical site-specific constraints that Engel et al. do not consider, such as fiber connectivity and water access. For each site, we also develop a mixed-integer linear programming model to rigorously co-optimize the hybrid solar+storage configuration and dispatch of the gas plant and storage, for the greatest possible constant data center load each site could support. Finally, we study the degree to which bulk system peak demand coincides with data center backup needs – and the cost of building and operating systems that avoid this coincidence – by constructing scenarios in which the gas plant is excluded from providing backup to the data center during peak bulk system demand thresholds of 1%, 5%, and 10%.

Economics of hybrids for data centers

We identify 68 existing natural gas-fired power plants across the U.S. - totaling 36 GW of capacity - that have data centers currently under development in close proximity (within 10 km). These plants are generally underutilized: the combustion turbines (CTs) operate at an average capacity-weighted capacity factor of 9.5%, while the combined cycle units (CCGTs) average about 59.6%. After screening each site against a comprehensive set of more than 50 land-use exclusion criteria, most sites (60 out of 68) retain enough area potential to host a solar capacity of at least five times the plant's gas-fired capacity (Chojkiewicz et al., 2025). Using eight years of hourly irradiance and temperature data from PVGIS–ERA5, corresponding to 2016-2023 (chosen because they correspond to the maximum number of consecutive years for which both consistent hourly solar and regional demand data are available), we simulate solar output at each selected site (European Commission, 2025). Then, using the latest technology cost projections, we identify site-specific least-cost hybrid system configurations - including solar, DC-coupled storage with an energy to peak power ratio of up to six hours, and at most 5% of energy served by gas backup - that can supply data center demand, using a conservative constant demand assumption. We initialize the problem by setting the load equal to the existing gas capacity at each site, then decrement if the problem is infeasible due to the limited solar potential at the site [Figure 1a].

As seen in Figure 1b-c, the optimized hybrids are not only operationally feasible but cost-competitive: the resulting Levelized Cost of Energy (LCOE) for the solar+storage system with up to 5% gas backup ranges from $60-138 MWh, assuming a 2028 commissioning date. Spatial variation highlights sunbelt states (Texas, Nevada, Arizona, Utah, California, Florida) as particularly well-suited for low-cost deployment. Costs are largely driven by local solar insolation, diurnal and seasonal storage needs, and operational gas constraints. Further, the sale of excess (otherwise curtailed) solar generation reduces the LCOE by an average of $18/MWh across all sites. This estimate is likely conservative, as it assumes a constant, flat demand profile, whereas data centers are known to exhibit spiky load profiles that could increase the value of excess generation (NERC, 2025).

While this cost range is at or above most states' industrial tariffs - and the ability to take advantage of these tariffs is limited by grid connection constraints and lengthy timelines - it is competitive with data centers' recent contract prices for 24/7 clean power. For example, Microsoft's cost of nuclear power from the Three Mile Island plant is estimated to be at least $100-$115/MWh and up to $140/MWh including transmission, while Amazon's cost of nuclear power from the Susquehanna plant is valued at roughly $82-88/MWh, exclusive of grid costs (Leith-Yessian, 2025; Salzman, 2025). Further, 56 of the 68 sites (82%) we evaluated can support a constant load equivalent to the gas capacity at each site, resulting in a total 29.7 GW of constant load nationwide - highlighting the substantial tens of GW scale of demand these hybrids can reliably serve. Across all plants, the emissions factor ranges from 0.02-0.03 kg CO_2/kWh of data center energy served, depending on the site's gas technology mix. In contrast, Google - an industry leader with a 24/7 carbon-free energy goal by 2030 - has an emissions factor ranging from 0.08-0.6 kg CO_2/kWh across the U.S. for their Cloud services (Google, 2025).

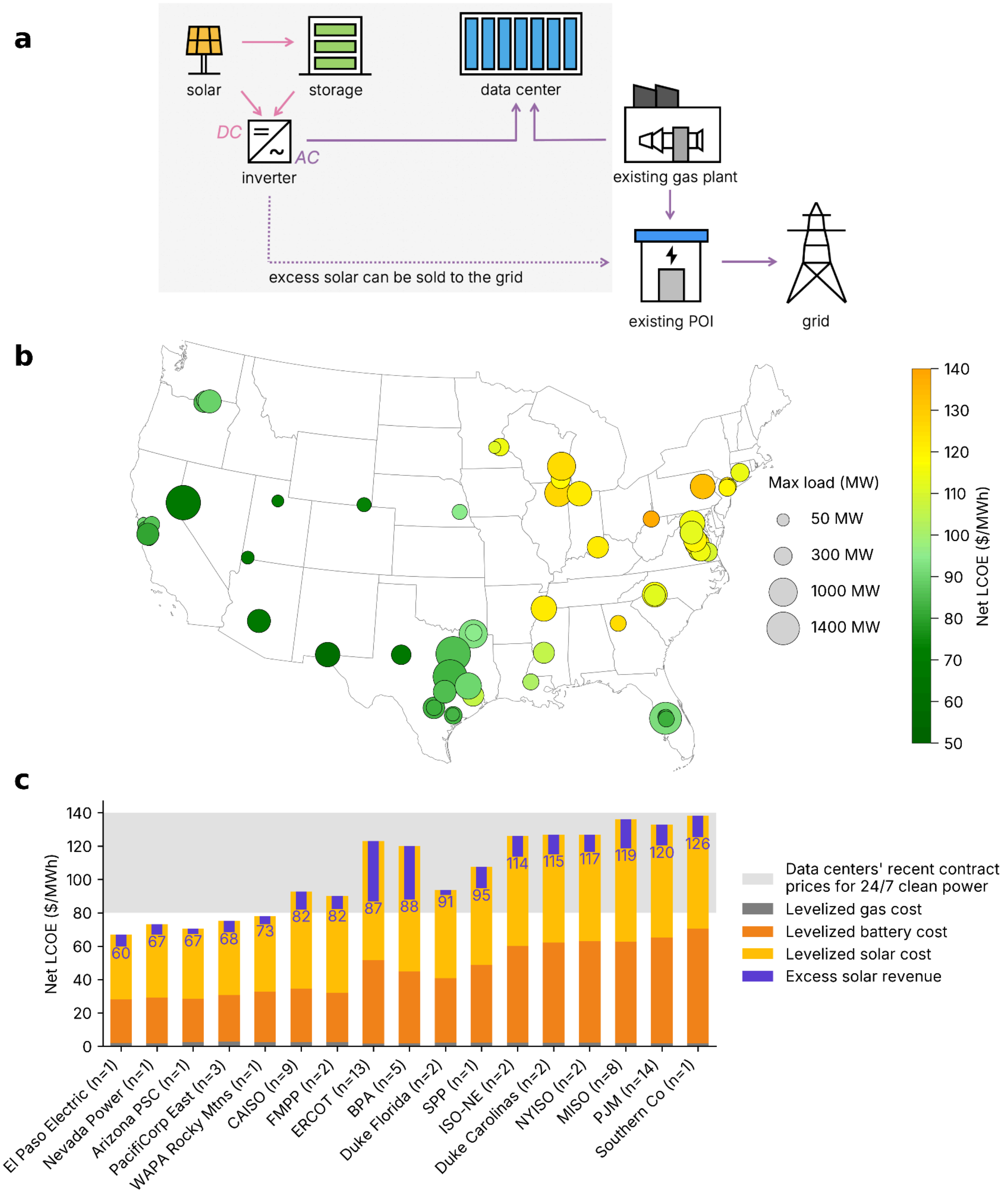

Figure 1: Concept and costs of siting a data center at an existing gas plant with surplus solar+storage. (a) The solar+storage serves the majority of the data center's load, with the gas plant providing at most 5% backup as needed; excess solar is sold to the grid. (b) The regional averages of the net levelized cost of the hybrid system range from $60-91/MWh in sunbelt regions, rising to $95-126/MWh in midwestern and northeastern regions. Plants located in close proximity are slightly offset for visibility. The size of the bubbles corresponds to the maximum constant load each site could support, constrained by the local solar potential driven by land availability; 56 of the evaluated 68 sites can support a constant load equivalent to the site's existing gas capacity, for a total of

29.7 GW nationwide. [c] Levelized cost breakdown of the net LCOE, adjusted for revenue obtained from selling surplus energy and compared to data centers' observed contract prices for 24/7 clean power, which ranges from $80-140/MWh (Leith-Yessian, 2025; Salzman, 2025). LCOE values are load-weighted averages across all sites in each region, with the number of sites (n) indicated on the x-axis. Costs are reported in 2025 US$.

Decoupling backup needs from grid stress

There is growing concern that large technology companies contracting or co-locating with existing natural gas plants, without associated new generation, could create reliability and economic risks for the power system (Norris et al., 2025). Specifically, diverting gas capacity to industrial loads may intensify competition for scarce resources, reduce reserve margins, raise costs for other consumers, and threaten overall system adequacy. To address this, we analyze the alignment between periods of grid stress and localized backup needs of solar+storage systems to meet a constant data center load. We assign each site to its independent system operator (ISO) or balancing area, and use hourly system demand data for 2016-2023 as a proxy for grid stress. For the top 1%, 5%, and 10% peak demand hours, we restrict gas generation from serving the local load and re-optimize the capacity and dispatch of the least-cost hybrid system configuration. Comparing these cases with the baseline (in which the gas plant is capable of providing local backup to the data center in all hours) allows us to identify "conflict hours", defined as periods in which the gas plant would provide data center backup during peak demand hours. Restricting gas operation for the local data center load during the top 1%, 5%, or 10% peak demand hours deconflicts local backup by reserving gas capacity for system needs. This enables us to quantify the cost premium associated with preventing gas plants from providing data center backup - highlighting the economic trade-offs of co-locating large loads with existing gas capacity.

Results show limited conflict hours across most regions of the U.S. due to a clear seasonal and diurnal separation between local backup needs and system needs. As showcased in the heatmaps in Figure 2, backup for a solar+storage system supplying a constant load occurs primarily during winter nights (left column), whereas system demand has historically peaked on hot summer afternoons (middle column). Most regions - including CAISO, ERCOT, PJM, MISO, and ISO-NE - typically experience few conflict hours: for example, in 2022, gas plants in these regions exhibited 15 or fewer conflict hours (0.2%) (left column), which can be addressed with operational adjustments such as shifted charging and discharging of the battery. Therefore, restricting gas operation for the local load during the top 10% peak demand hours results in a deconflicted gas dispatch (the right column) that closely matches the baseline (additional scenarios, regions, and years are found in Supplementary Figures 1-5).

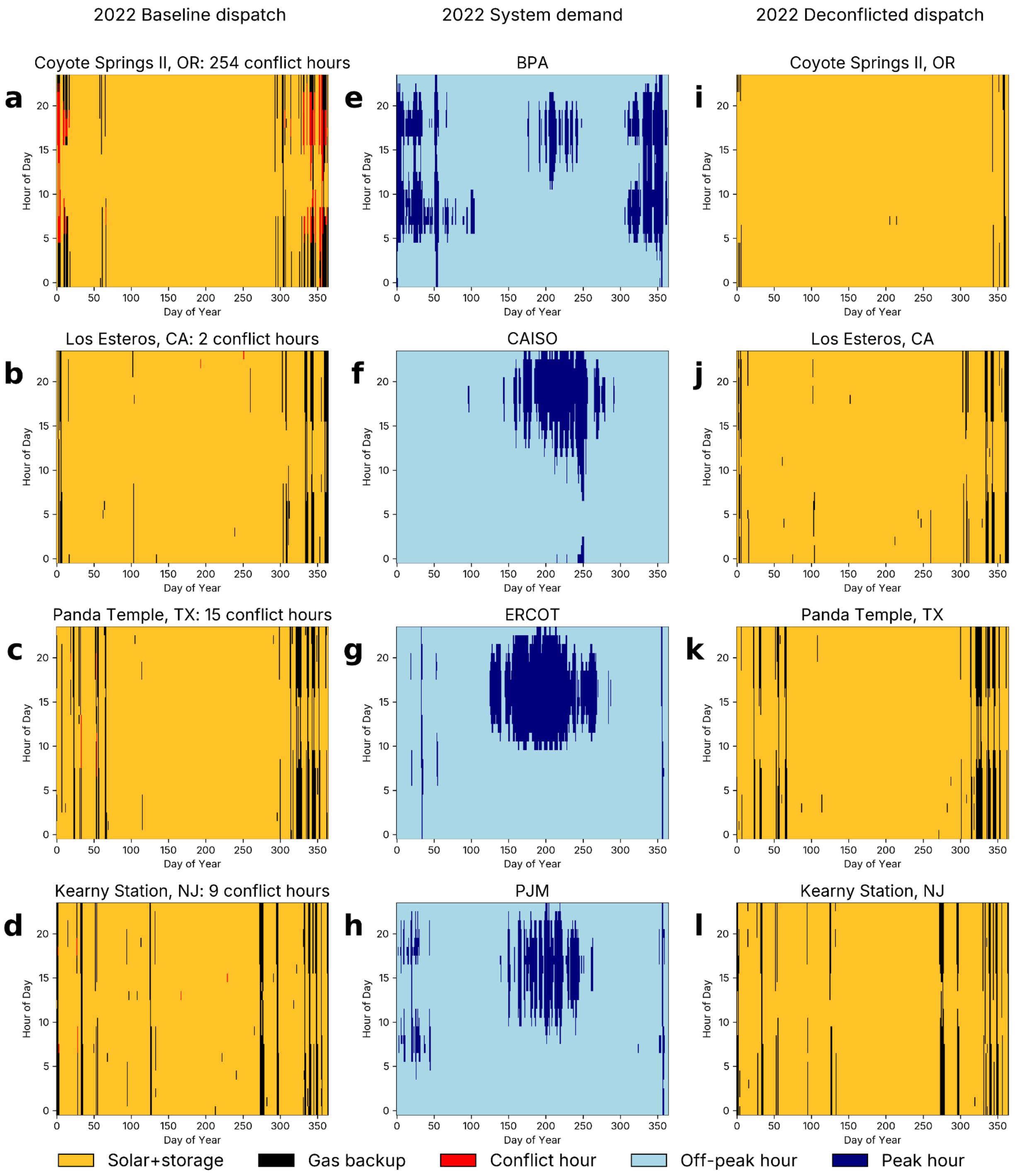

Figure 2: A solar+storage system serving a constant data center load may produce "conflict hours" (a-d), when gas backup overlaps with high system demand (e-h). Restricting gas for the local load during the top 10% peak demand hours reserves gas capacity for the grid, mitigating conflicts and allowing the plant to serve both local and system needs year-round (i-l). Conflicts are generally limited due to seasonal and diurnal separation: backup is mostly needed on winter nights, while system peaks occur on summer afternoons. These small conflicts can be managed with operational adjustments, but substantial conflicts such as in BPA (a, e, i), require notable changes to the solar+storage configuration. Regions shown here illustrate geographic variation, with the median-LCOE plant selected to represent each region; additional scenarios, regions & years are found in Supplementary Figures 1–5.

The major exception is the Bonneville Power Administration (BPA), where morning and afternoon winter peaks result in 254 conflict hours in 2022 [Figure 2a]. In this case, conflict mitigation cannot be addressed through operational adjustments alone, necessitating significant changes to the configuration of the solar+storage system: the least-cost deconflicted solution increases the optimal solar capacity by 17% and increases the battery energy capacity by 2.3 times relative to the baseline. To illustrate how the resolution of these conflicts changes operations of the hybrid system, Figure 3a-b presents a week of dispatch at the Coyote Springs II plant during a cold, low-insolation week in January 2022. In the baseline case, the least-cost solution identifies continuous gas operation on January 3 and 5 - days with exceptionally low solar generation - such that it is optimal to run the gas unit, discharge the battery, and use the limited solar output to recharge the battery when possible. However, restricting gas operation for the local data center load during the top 10% peak demand hours limits gas use for solar+storage backup to overnight hours, when system demand is lowest. Increased battery energy capacity enables discharge during hours when the gas plant may be required to serve the bulk power system, thereby meeting the local load.

Deconflicting the gas dispatch incurs a cost premium in some regions, but not in others, as shown in Figure 3c. Specifically, plants in BPA, and to a lesser extent ERCOT, require a higher capital cost of the solar+storage system to deconflict. However, critically, in most regions these noncoincident needs - i.e., the temporal separation between backup demand and system peaks - mean that existing gas plants can cost-effectively provide dual services: delivering backup to the solar+storage system while remaining available to support the wider grid during system peaks.

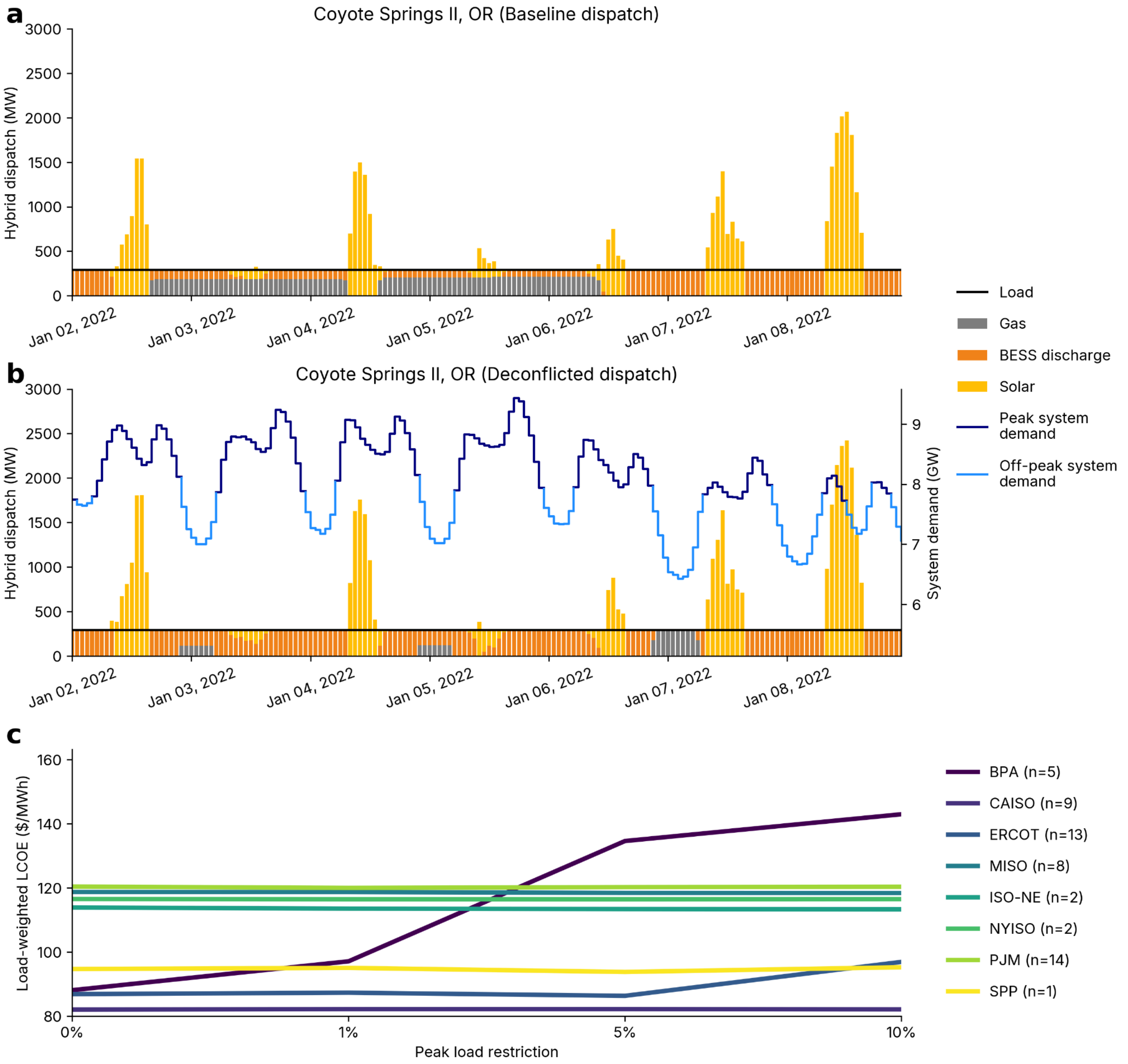

Figure 3: Dispatch for a cold, low-insolation week in January 2022 at the Coyote Springs II plant in BPA illustrates gas operation without (a) and with (b) restricting gas for the local load during the top 10% peak demand hours. Deconflicting may incur a cost premium (c), which is substantial in BPA but negligible in most other regions where solar+storage backup demand and system peaks are noncoincident - i.e., temporally separated - and can be addressed through operational adjustments. Meanwhile, in BPA, restricting local gas use confines operation to overnight hours and requires a larger battery. LCOE is shown as the load-weighted average across all sites in each region, accounting for surplus energy sales; the number of sites (n) is indicated in the legend.

While here we use system peak demand as a proxy for grid stress, the potential to deconflict hybrid backup requirements from system needs depends on the clarity and efficiency of market signals. In day to day operations in restructured markets, this may take the form of day-ahead and forward price formulation providing sufficiently strong incentives to manage the relatively limited number of hours in which hybrid backup needs and high system load coincide. Effective price signals enable battery storage to respond dynamically to temporal variations in energy value, such as charging in advance of reliability and/or extreme weather events. This also applies in cases where the data center has a variable load profile, and that variability creates headroom that can be monetized through energy exports (further reducing the net cost of the hybrid system). Alternatively, conflict hours could be avoided with strong regulatory signals, such as those being considered in DOE's Advanced Notice of Proposed Rulemaking (ANOPR) (DOE, 2025). Since the system's capability to deconflict is primarily determined by the initial capital investment - except in cases where modular expansion of solar or storage capacity is feasible, contingent on land availability and demand - investment decisions must be coordinated between the data center customer and the solar+storage developer to ensure sufficient capacity for conflict mitigation will be built. This is particularly relevant as the electrification of building heating advances: winter peaks may become increasingly consequential, signaling that both the timing and frequency of potential conflicts between backup requirements and system needs are likely to evolve in the future (Keskar et al., 2023).

Nationwide potential for siting large loads

Beyond the 68 sites with commercially active data center interest analyzed above, the U.S. has over 1,000 natural gas-fired power plants, totaling over 457 GW of installed capacity. Based on the available land at these sites for solar development, we estimate the nationwide potential for co-locating large loads with hybrid solar+storage systems. Our estimates apply the previously derived ratios of the optimal solar capacity to constant plant load at each of the 68 configured sites, and then scale these results to the state levels to approximate the constant flat load that each existing gas plant could support. For plants in states that did not have a data center in the original set of 68 data centers, we assign a solar-to-load ratio based on the geographically nearest modeled plant; overall, 72% of plants rely on state-level empirical ratios, while 28% require this nearest-neighbor inference.

Aggregating across all plants, we find that the total nationwide potential is 333 GW, with the largest opportunities in states like Texas (45 GW), followed by California and Florida, where ample land is available [Figure 4b]. This value represents an upper bound on the potential to leverage existing fossil infrastructure for near-term power for large loads. Real-world deployment will be shaped by several practical constraints: data centers typically require adequate fiber connectivity and water access for cooling (BNEF, 2025); industrial loads - such as semiconductor fabrication or other clean tech manufacturing - may depend on specialized labor pools; and local permitting processes may impose additional barriers. Nevertheless, where these constraints can be addressed, co-locating large loads with hybrid solar+storage systems at existing gas plants offers substantial potential to meet large loads' power needs.

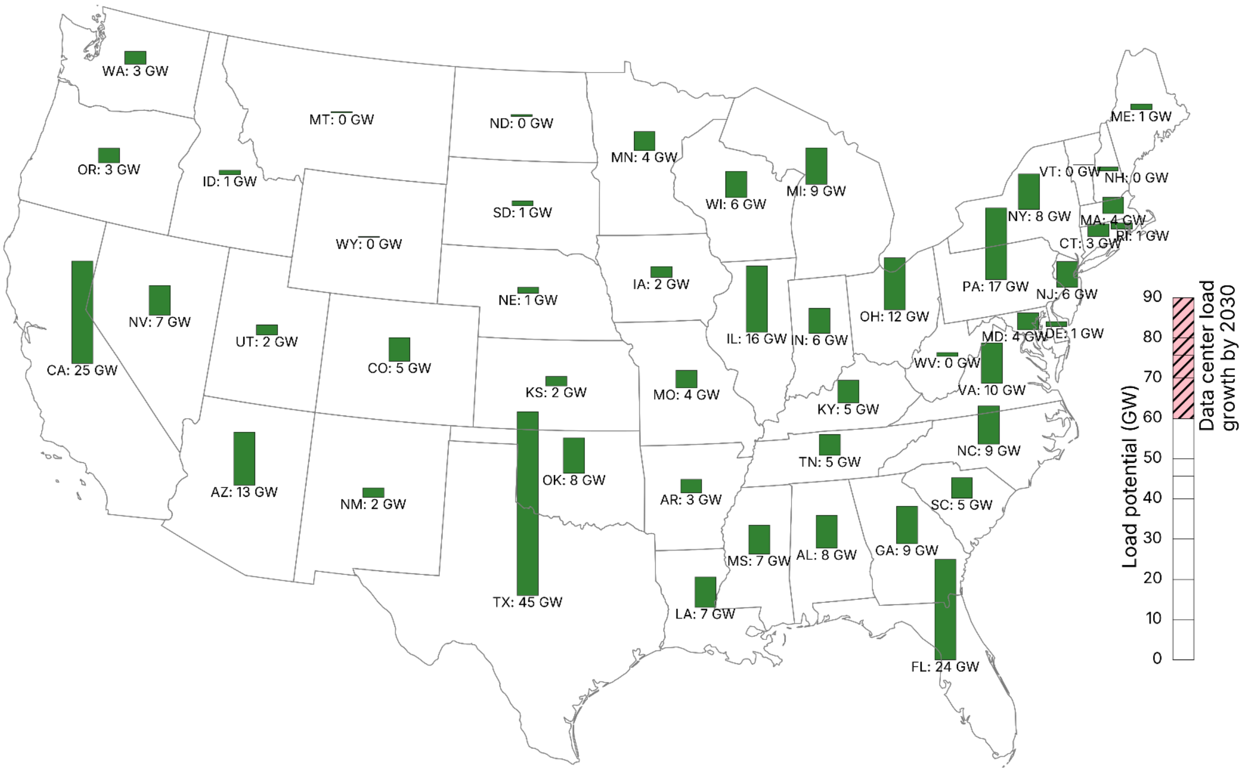

Figure 4: The potential to co-locate a constant flat load near existing gas plants totals 333 GW nationwide, while an additional 60-90 GW of new data center load is projected by 2030 (Grid Strategies, 2025).

Discussion

Our results show that data center developers - and large loads more broadly - have a practical, near-term pathway to secure clean, reliable power: hybridizing existing gas plants with surplus solar+storage. By leveraging existing interconnection rights and infrastructure along with noncoincident needs, this approach offers competitive costs, relies on commercially available technology, and can be deployed quickly - leaning on solar and storage, capitalizing on solar and storage, the fastest-growing sources of new electric generating capacity in the past year (EIA, 2025). Further, these technologies' modularity allows capacity to scale with data center demand, yet if a planned data center does not materialize - or later relocates - the hybrid system need not become stranded: the solar+storage capacity remains a lower-cost grid resource, displacing aging gas generation, reducing local emissions and operating costs, and mitigating risks. Moreover, data centers may exhibit high short-term variability in active power demand and are sensitive to voltage and frequency disturbances that can trigger rapid disconnection, creating operational stability challenges (NERC, 2025). Co-locating fast-responding, power electronics-based solar and storage near these facilities helps dampen these fluctuations, shielding both the local load and the broader grid (Aurora, 2025).

Real-world deployment will require coordination among plant owners, regulators, utilities, and large loads to ensure that these hybrid systems operate in ways that benefit both the host site and the broader grid. A practical contractual structure would involve an arrangement in which the existing gas plant owner either sells to or partners with a solar+storage developer, which builds, operates, and sells power to the industrial user through a long-term PPA. Both the large load customer as well as the solar+storage developer should rigorously determine backup requirements, considering solar insolation, the gas plant's historical operation patterns along with its contribution to system reliability, and the data center's willingness to provide flexibility and/or tolerate curtailment if the hybrid system cannot supply its load. The latter is particularly relevant in the regions of BPA and ERCOT with notable conflict. Utilities should facilitate the identification and prioritization of suitable sites and streamline the transfer or reuse of interconnection rights. Emerging regulatory efforts, including DOE's recent ANOPR on large load integration (DOE, 2025), underscore the importance of aligning incentives so that large loads, especially with co-located resources, support rather than burden the grid. Regulators should also address persistent barriers to surplus interconnection service, including standardizing regional best practices, developing pro forma agreements for interconnection sharing, enabling surplus resources to qualify for capacity credits through expedited deliverability studies, and defining procedures for the streamlined transfer of interconnection rights if the original generator retires (Mattioda et al., 2024; Castillo et al., 2024; Farmer and Silverman, 2025; Chojkiewicz et al., 2025). This includes creating formal surplus interconnection processes in ERCOT and NYISO, which currently lack such mechanisms. Future work should examine detailed grid-level impacts under more realistic and potentially highly variable load profiles, as well as the broader social, community, and environmental justice implications of changes in utilization, siting, and longevity of existing power system infrastructure.

Methods

Site selection

We reviewed datasets of existing and proposed data centers from both open-source and proprietary sources, ultimately selecting the (Hitachi, 2025) dataset for its comprehensive facility-level detail. We filtered facilities to those classified as ‘proposed’ or ‘under construction’ as a proxy for active commercial interest, assuming that such sites have passed preliminary siting screens (e.g., fiber access, water availability) (BNEF, 2025; Arzumanyan et al., 2025). We then spatially linked these facilities to existing U.S. natural gas-fired power plants - with either combustion turbines or combined-cycle units - within a 10 km radius, consistent with (Chojkiewicz et al., 2025). Units using other fuels or technologies at these plants were excluded. This procedure identified 68 sites, reflecting 36 GW of capacity - with 1627 data centers under development nearby. We verified that their geographic distribution reflects current U.S. data center development trends.

Local solar potential

The potential solar resource that can be developed at each site is derived from (Chojkiewicz et al., 2025; Paliwal, 2025), which within a 10 km radius around each existing gas plant, analyzed the renewable resource potential of each 30x30m (100x100 ft) parcel of land through high-resolution satellite imagery and applying site exclusions based on physical site characteristics (i.e. land cover, slope gradients, elevation constraints) and land use (i.e. environmental protection status, parks and wilderness areas, development restrictions, military land).

Solar resource profiles

To generate the solar resource profiles, we used the Photovoltaic Geographical Information System (PVGIS) with the ERA5 reanalysis dataset produced by the European Centre for Medium-Range Weather Forecasts (ECMWF) (European Commission, 2023). ERA5 provides hourly irradiance, temperature, and meteorological variables on a $0.25° \times 0.25°$ grid, assimilated from satellite and ground-based observations, from 2005 to 2023. For each site, PVGIS was queried with site-specific latitude and longitude, and standard fixed system parameters (tilt equal to latitude, and south-facing azimuth). System losses were set to zero, as these were incorporated later in the optimization. PVGIS-ERA5 returns mean DC power in W per kWp; this series was then converted to local time, shifted and resampled to match the temporal resolution of the modeling framework, and then normalized to kW per kWp.

Technology costs

To estimate the levelized cost of solar and storage, we obtain capital and operating expenditures along with financial parameters from (BNEF, 2024) and convert to 2025 US$. The capital cost build-up and progression over time can be seen in Supplementary Figures 6 and 7. We assume a project commissioning year of 2028, assuming a 3-year development timeline. We also use a cost of equity of 8%, cost of debt of 512 basis points, a debt ratio of 70%, a project economic lifetime of 25 years, resulting in a WACC of 6% and CRF of 0.078 (BNEF, 2024). The solar fixed operations and maintenance (O&M) cost is assumed to be $16,096/MW/yr while the battery storage fixed O&M cost is assumed to be $2,373/MW/yr. For the natural gas costs, we use the estimated variable costs from (Chojkiewicz et al., 2025).

Optimization model

For each site, we solved a mixed-integer linear optimization problem to determine the least-cost configuration of a hybrid DC-coupled solar+storage system with maximum 5% gas backup. The model minimizes the total annualized cost of meeting a constant flat load - the most conservative demand profile - over 8 years of hourly data, subject to technology-specific operational constraints (MIT Energy Initiative and Princeton University ZERO lab, n.d.; Manocha et al., 2025; Ramasamy et al., 2021; Fu et al., 2018). The 8 years of hourly data (2016-2023), which was the longest continuous period for which both hourly electricity demand and solar irradiance datasets were available.

Decision variables include the solar capacity S (MW), battery power capacity B^{MW} and energy capacity B^{MWh}, hourly dispatch of solar s_t, battery charge c_t and discharge d_t, and state of charge SOC_t. Depending on the type of gas technology at each site, we include hourly generation from CTs g_t^{CT} and/or CCGTs g_t^{CCGT}, along with binary commitment variables indicating the battery mode $b_t \in \{0, 1\}$ (discharging and charging, respectively), the gas status x_t^{CT}, $x_t^{CCGT} \in \{0, 1\}$ (off and on for the local load, respectively), continuous gas startup/shutdown indicators u_t^{CT}, u_t^{CCGT}, d_t^{CT}, d_t^{CCGT}, and if relevant, whether or not gas is allowed to operate in a given hour $a_t \in \{0, 1\}$ (blocked and allowed, respectively). The objective is

$$\min_{S,\, B^{MW},\, B^{MWh}} \sum \left(Capex \;+\; Opex \;+\; Fuel\, cost \;+\; Startup/shutdown\, cost\right)$$

with

- $Capex \;=\; (C_S(S) \;+ C_B(B^{MW}, B^{MWh}))$ with C_S, C_B being the annualized capital costs of solar and the battery storage, respectively, annualized using the Capital Recovery Factor, CRF;
- $Opex \;=\; (O\&M_S(S) \;+ O\&M_B(B^{MW}))$ with $O\&M_S$, $O\&M_B$ being the annual fixed operating & maintenance costs of solar and the battery storage, respectively;

- $Fuel\ cost\ = (\sum_{t=1}^{T} g_t^{CT} c^{CT} + g_t^{CCGT} c^{CCGT})/y$ with c^{CT}, c^{CCGT} being the gas variable costs summed over all hours, and annualized, with y the number of years in the considered time interval (8);
- $Startup/shutdown\ cost\ = (\sum_{t=1}^{T} C_u^{CT} u_t^{CT} + C_u^{CCGT} u_t^{CCGT} + C_d^{CT} d_t^{CT} + C_d^{CCGT} d_t^{CCGT})/y$ with C_u^{CT}, C_u^{CCGT} being the startup cost and C_d^{CT},C_d^{CCGT} being the shutdown cost per Supplementary Table 1, summed over all hours, and annualized.

Subject to:

- Energy balance: $(s_t - c_t + d_t)\,\eta_{inv} + g_t^{CT} + g_t^{CCGT} = P^{load}\ \forall\, t$ where P^{load} is the constant target load
- Solar potential limit: $S \le S^{max}$ where S^{max} is the local solar potential at each site from (Chojkiewicz et al., 2025)
- Solar output limit: $s_t \le S \cdot \phi_t\ \forall\, t$ where ϕ_t is the hourly output from the solar resource profile
- Battery operation: $SOC_t = SOC_{t-1} + \eta_c c_t - d_t/\eta_d\ \forall\, t$ with battery efficiencies $\eta_c = \eta_d = \sqrt{RTE}$ and $SOC_0 = SOC_T$ for considered hours
- Battery energy limit: $0 \le SOC_t \le B^{MWh}\ \forall\, t$
- Battery sizing limit: $B^{MWh} \le 6\, B^{MW}\ \forall\, t$ to ensure realistic battery sizing, reflective of ongoing commercial activity
- Battery capacity limit: $B^{MW} \le S^{MW}\ \forall\, t$ to ensure realistic battery sizing, reflective of ongoing commercial activity
- Battery power limits: $0 \le c_t \le B^{MW} b_t,\ 0 \le d_t \le B^{MW}(1 - b_t)\ \forall\, t$
- Unit commitment: $x_t^{CT} g_{min}^{CT} a_t \le g_t^{CT} \le x_t^{CT} g_{max}^{CT} a_t$ and $x_t^{CCGT} g_{min}^{CCGT} a_t \le g_t^{CCGT} \le x_t^{CCGT} g_{max}^{CCGT} a_t$ are the minimum run rates per Supplementary Table 1 and g_{max}^{CT},g_{max}^{CCGT} are the existing CT and CCGT capacities
- Ramp rates: $\left|g_t^{CT} - g_{t-1}^{CT}\right| \le Ramp^{CT}$, $\left|g_t^{CCGT} - g_{t-1}^{CCGT}\right| \le Ramp^{CCGT}\ \forall\, t$ where $Ramp^{CT}$, $Ramp^{CCGT}$ are the ramp rates
- Continuous startup/shutdown indicators: $u_t^{CT} \ge g_t^{CT} - g_{t-1}^{CT}$, $d_t^{CT} \ge g_{t-1}^{CT} - g_t^{CT}$, $u_t^{CCGT} \ge g_t^{CCGT} - g_{t-1}^{CCGT}$, $d_t^{CCGT} \ge g_{t-1}^{CCGT} - g_t^{CCGT}\ \forall\, t$ used to compute penalties whenever a unit change state
- Gas generation limit: $\sum_{t=1}^{T} g_t^{CT} + g_t^{CCGT} \le (1 - A)\, P^{load}\, T$ where A is the required solar+storage availability factor

Where t is each hour in the set of all hours T. We initialize the problem by setting the load equal to the existing gas capacity at each site, i.e., $P^{load} = g_{max}^{CT} + g_{max}^{CCGT}$. If the problem is infeasible due to the solar potential limit, which may arise if the plant is located in an urban area - we decrement the P^{load} by the greater of 10 MW or 5% of the existing gas capacity until a feasible solution is found. For one site (Jack McDonough plant in GA), which initially lacked sufficient solar potential to meet the step size, we used smaller decrements of 25 MW (5 % of the before-last infeasible step) to identify a feasible load.

The problem is solved using Gurobi 10.0 with a 1% optimality gap. If a site contains no CT units or no CCGT units, the associated variables and constraints are omitted. For each site, the model returns the optimal solar PV and battery capacities; hourly solar generation, battery charge and discharge, gas dispatch, and curtailment; and resulting system costs. We additionally test an AC-coupled formulation that enables the gas to charge the battery while the solar serves load, yet preliminary testing resulted in similar system configurations with a slight increase in cost.

Levelized Cost of Energy (LCOE)

From each site's resulting costs, we can calculate the LCOE using annualized capital costs of solar and battery storage (computed using the CRF), annual fixed operating & maintenance costs of solar and battery storage, annual gas fuel costs, and dividing by annual power generation. The annual gas fuel cost is calculated as the total gas generation over the simulated time interval multiplied by the respective variable costs of the CTs and CCGTs at each site, then divided by the number of years simulated (8) to annualize.

To estimate the curtailment revenue, we used the "solar value" reported in LBNL's Utility-Scale Solar Report, 2024 Edition (Seel et al., 2024). Each plant is matched to its corresponding LBNL region - typically an ISO or Balancing Authority - and in the single case where no region exists (El Paso Electric), we assign it to the closest available region (ERCOT) (for the mapping of the demand region to the LBNL region, see Supplementary Table 2). We rely specifically on the reported "solar energy values," excluding "solar capacity values," because curtailment reflects excess energy, and surplus resources generally do not qualify for capacity credits without additional deliverability studies. Values are inflation-adjusted from 2023 USD to 2025 USD (6.6%), then multiplied by inverter efficiency η_{inv} and each plant's curtailed MWh to estimate total curtailment revenue per scenario (0%, 1%, 5%, 10%), scaled to the project lifetime.

The LCOE equation is therefore:

$$LCOE = \frac{(C_S(S) + C_B(B^{MW}, B^{MWh}) + O\&M_S(S) + O\&M_B(B^{MW})) + (\sum_t g_t^{CT} c^{CT} + g_t^{CCGT} c^{CCGT})/y}{(\sum_t^T P_{load})/y} - \frac{V_s \cdot E_{curt} \eta_{inv}}{(\sum_t^T P_{load})/y}$$

where V_s is the solar energy value ($/MWh), and E_{curt} is the average annual curtailed energy for each scenario.

Conflict analysis

For the conflict analysis, we use system demand as a proxy metric for grid stress - over other metrics such as locational marginal prices or historical plant dispatch - due to its consistent and widespread data availability across all sites and regions. Each site is assigned to a demand region, typically defined by the relevant ISO or local balancing authority (for the mapping, see Supplementary Table 3). For each region, we obtain hourly system demand data over the selected study period from (Hitachi, 2025). We use 2016-2023, which provides the longest interval with complete data across all regions. We then impose three levels of peak demand restrictions - preventing the gas plant from serving the local load during the top 1%, 5%, and 10% of hours, as it is needed for the grid, through the binary gas allowed variable - and re-solve the optimization for each site under each restriction. We compare the resulting levelized cost, system configuration, and operational dispatch to the baseline scenario with no hours blocked (0%).

Nationwide potential estimate

We estimate the nationwide potential for siting constant load by first computing the ratio of optimal solar capacity to co-located constant flat load for each of the 68 optimized sites. We then calculate a state-level, capacity-weighted average of this ratio to capture variations in solar siting potential. Finally, we apply the state-level solar-to-load ratios to the nationwide set of gas plants (Chojkiewicz et al., 2025) to estimate the potential data center load at each site. For each plant, if the solar capacity needed to fully utilize the gas capacity exceeded the plant’s available solar potential, the potential data center load was limited by the solar potential; otherwise, the potential load was set equal to the total gas capacity. For sites which lie in a state that was not cost-optimized previously, we assign a solar-to-load ratio based on the nearest neighbor approach, using the geographically nearest modeled plant. Overall, 72% of plants rely on state-level empirical ratios, while 28% require this nearest-neighbor inference.

Author contributions

E.C., A.M., D.C., and A.P. designed research;
E.C., A.M., U.P. performed research;
E.C. analyzed data;
E.C., A.M., and D.C. wrote the paper

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Supplementary Figures

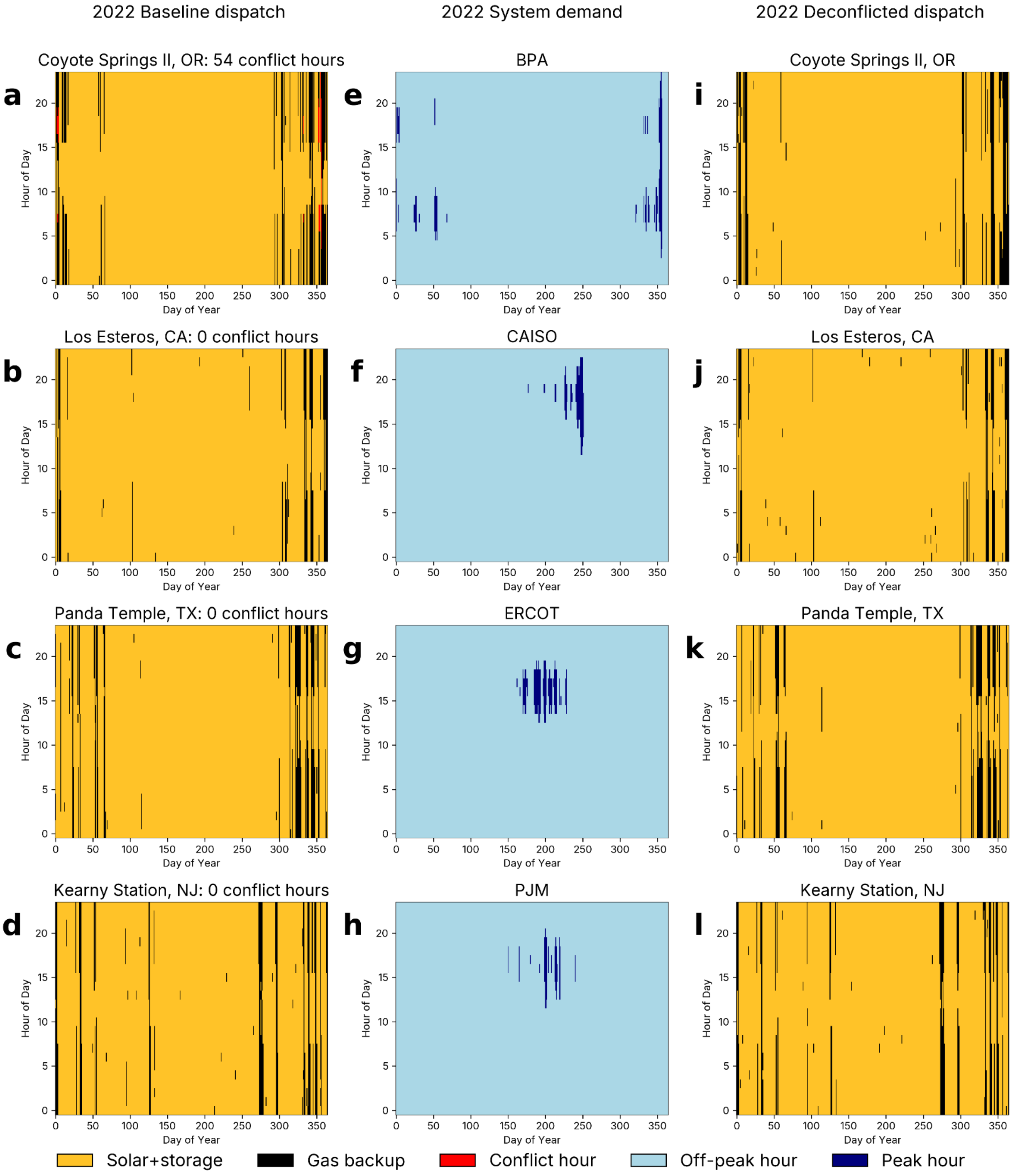

Figure S1. Heatmaps for BPA, CAISO, ERCOT, and PJM for 2022 with the top 1% of peak demand hours restricted for the local load.

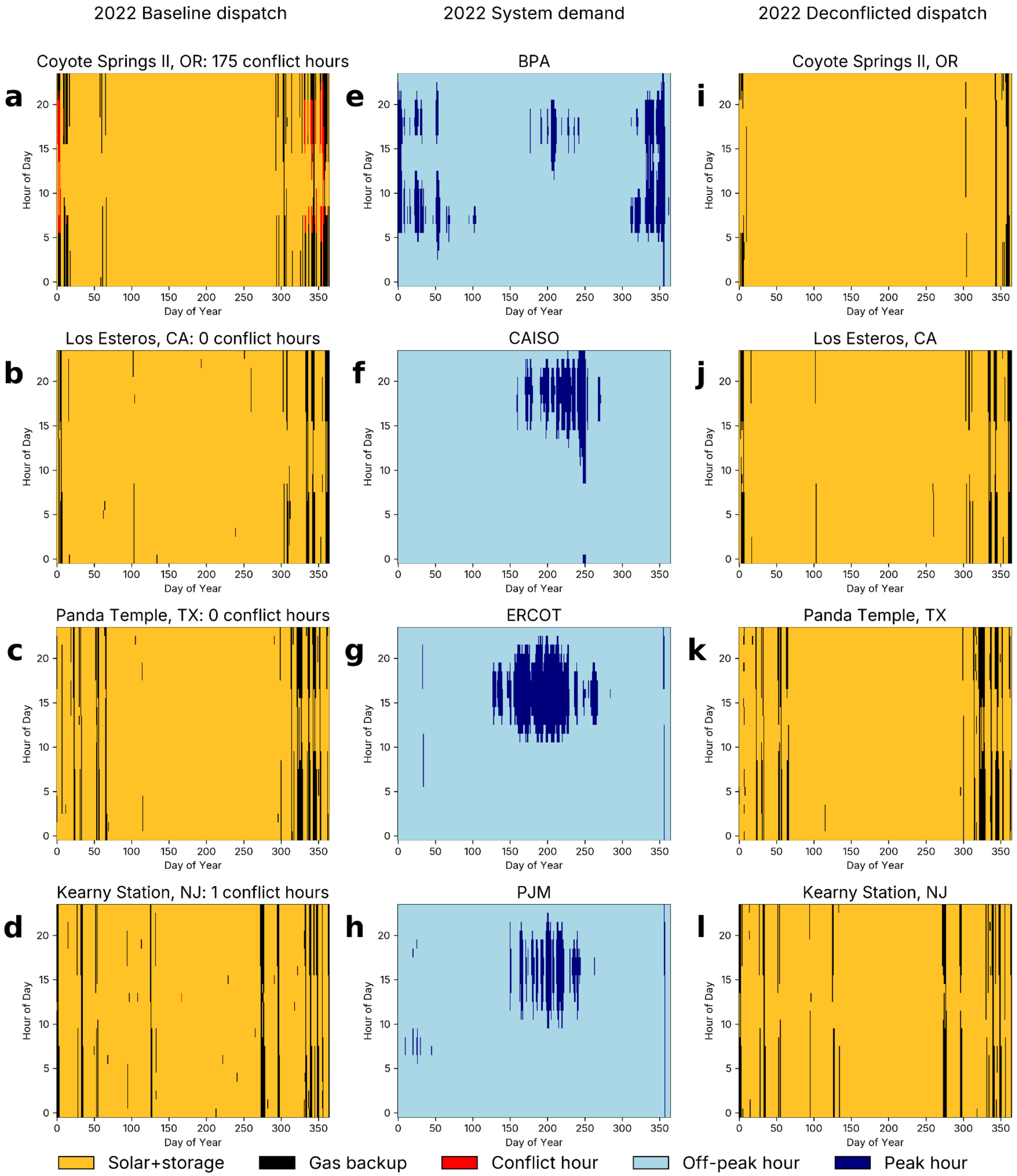

Figure S2. Heatmaps for BPA, CAISO, ERCOT, and PJM for 2022 with the top 5% of peak demand hours restricted for the local load.

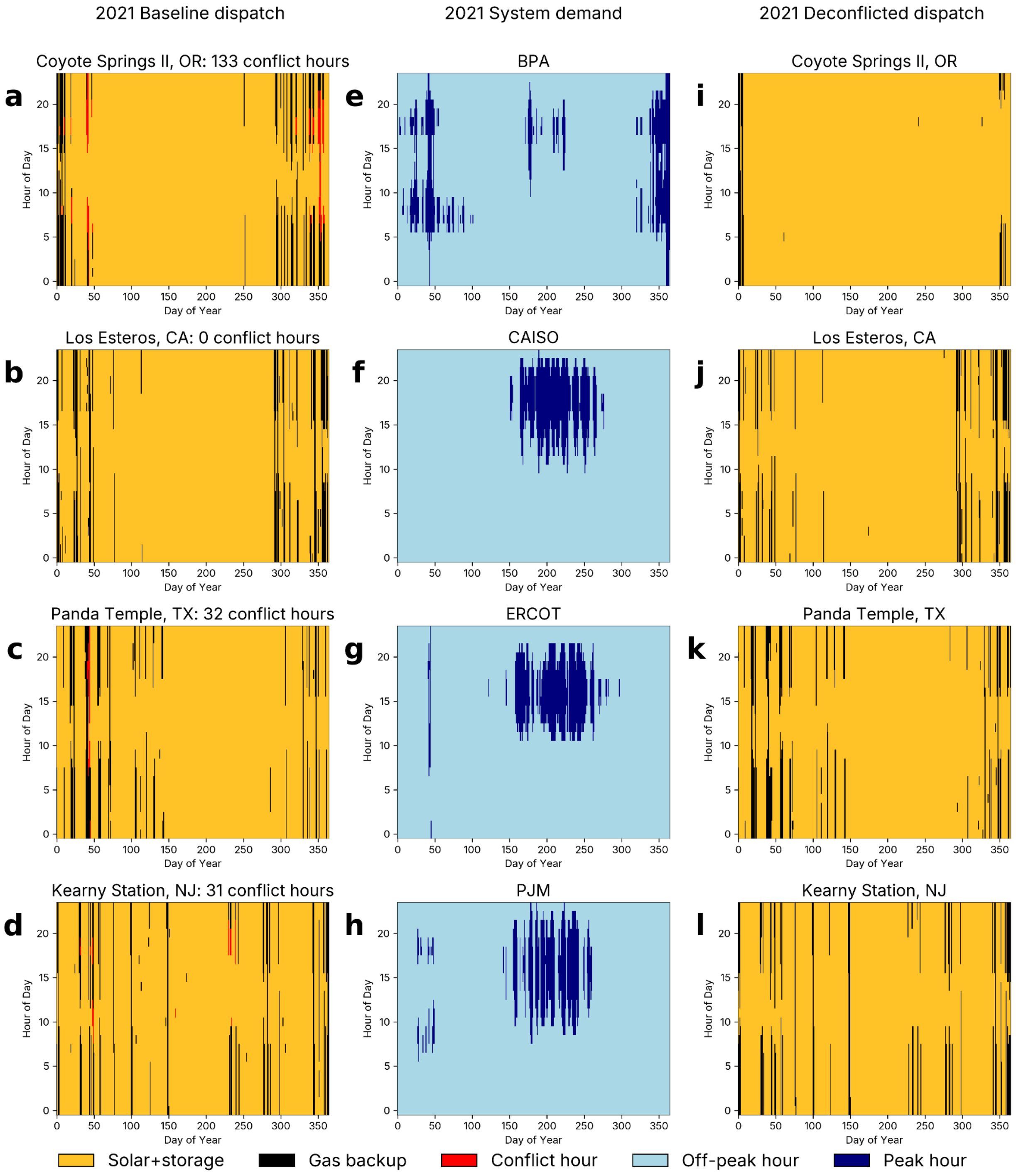

Figure S3. Heatmaps for BPA, CAISO, ERCOT, and PJM for 2021 with the top 10% of peak demand hours restricted for the local load.

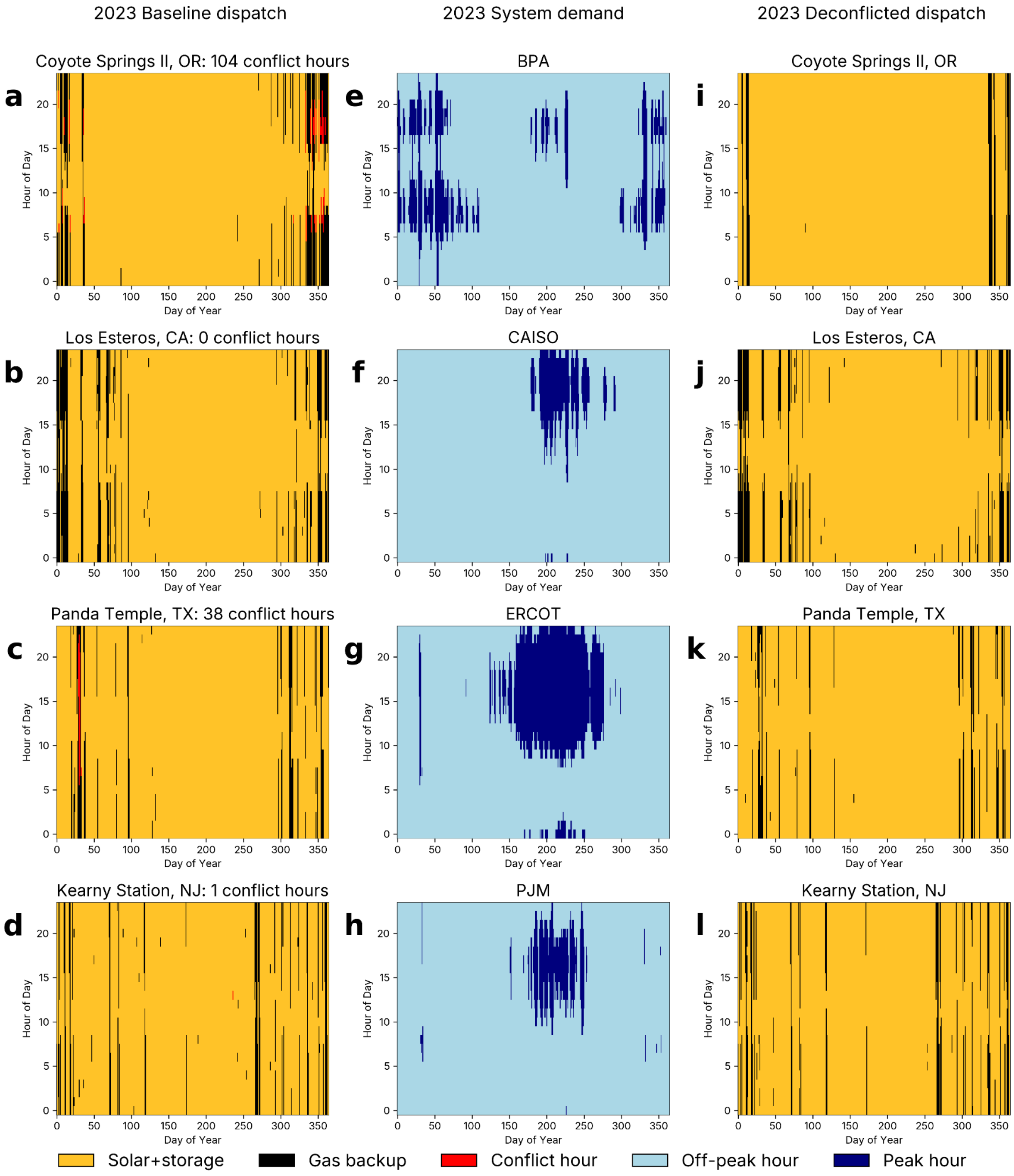

Figure S4. Heatmaps for BPA, CAISO, ERCOT, and PJM for 2023 with the top 10% of peak demand hours restricted for the local load.

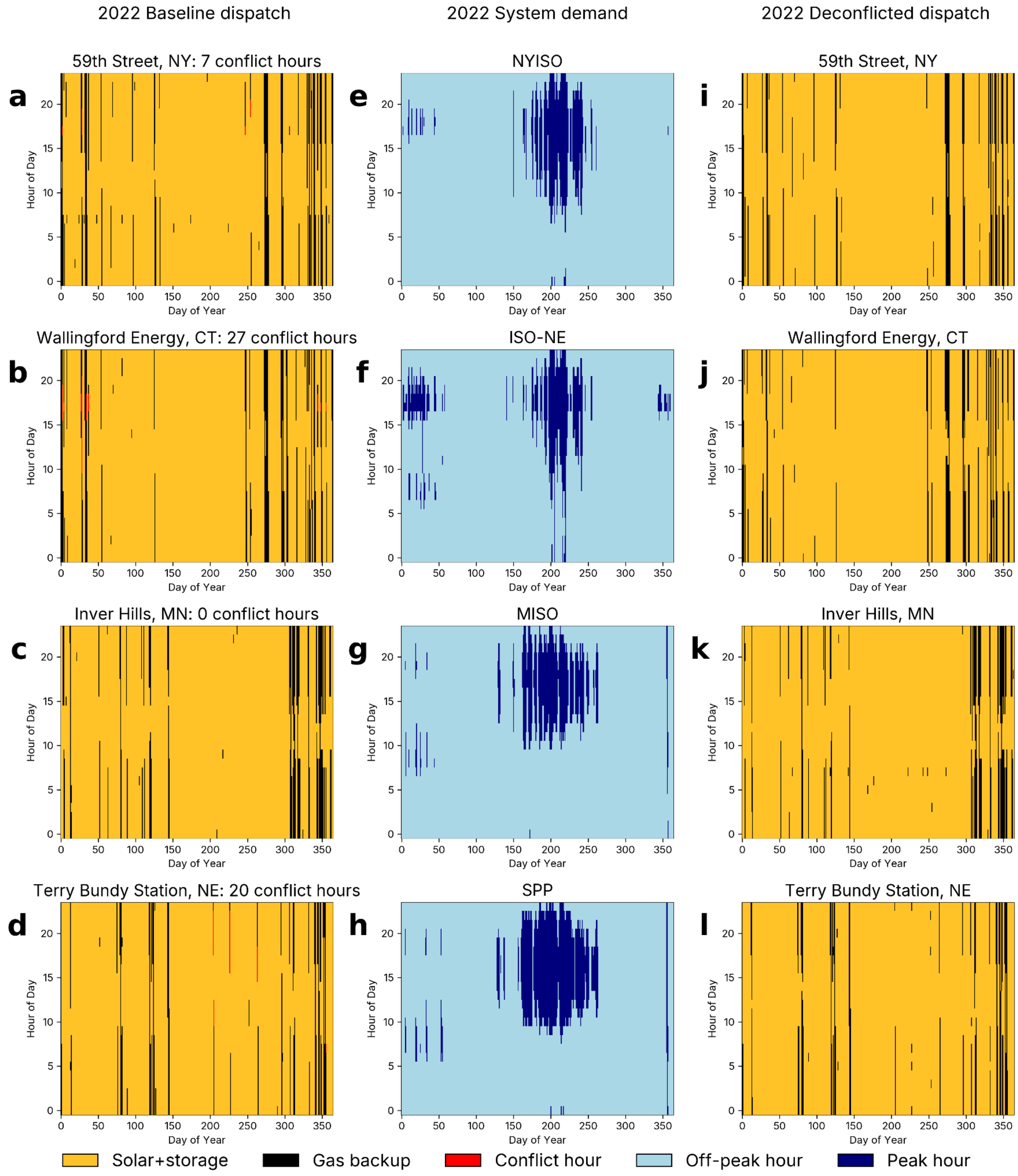

Figure S5. Heatmaps for NYISO, ISO-NE, MISO, and SPP for 2022 with the top 10% of peak demand hours restricted for the local load.

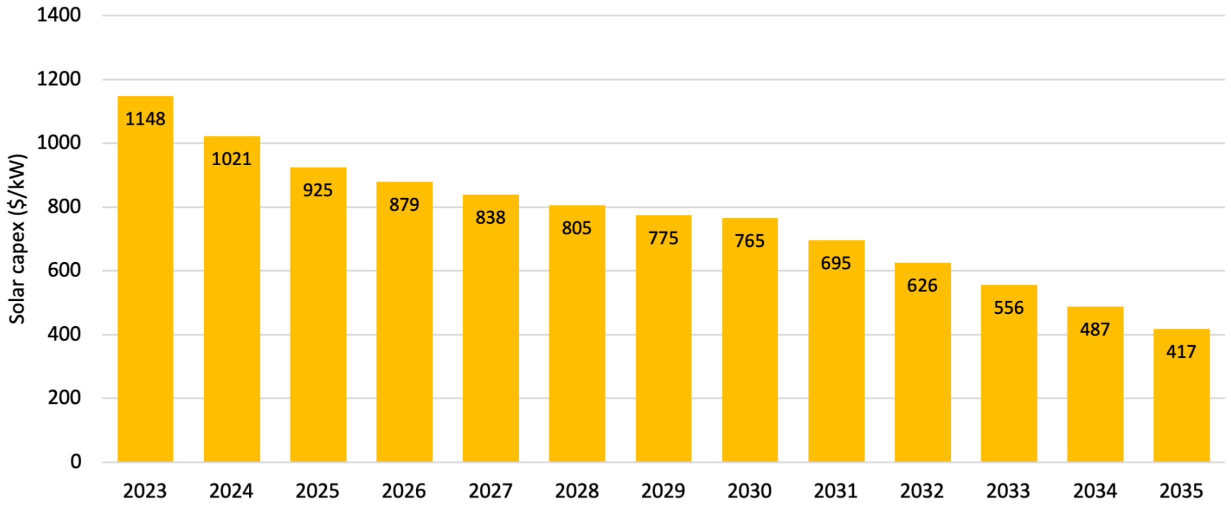

Figure S6. Progression of solar capital costs [1].

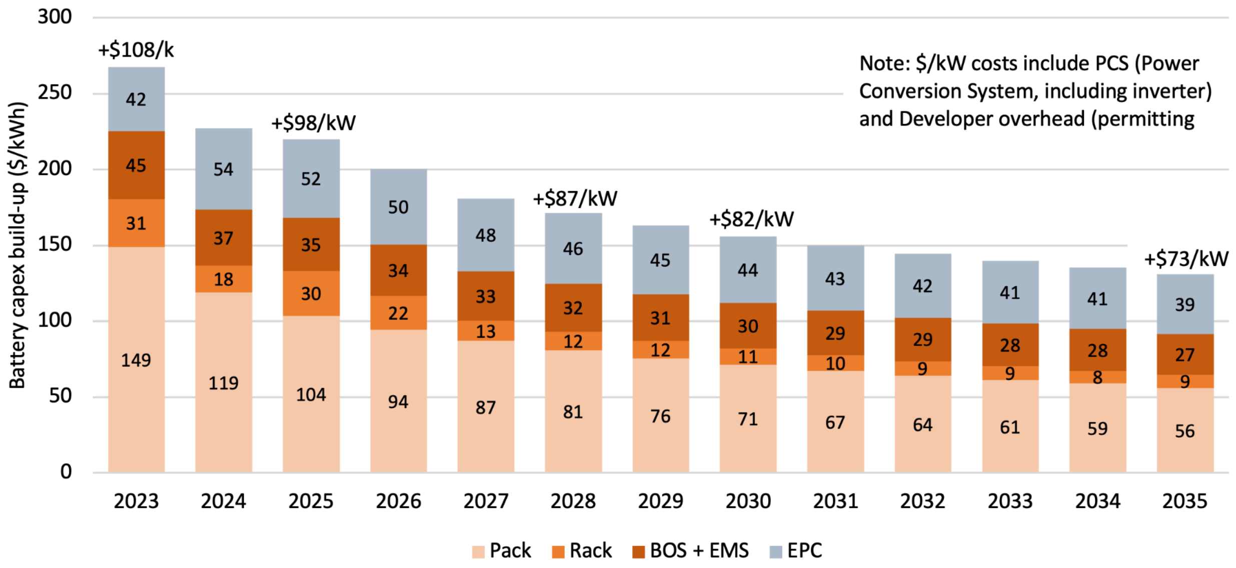

Figure S7. Progression and build-up of battery storage capital costs [1].

Table S1. Gas operational constraints [2-5].

Year	Gas CT	Gas CCGT
Ramp rate	100% of capacity/hr	60% of capacity/hr
Minimum run rate	20% of capacity	40% of capacity
Startup cost	$10/MW	$40/MW
Shutdown cost	$5/MW	$10/MW

Table S2. Demand region to LBNL Balancing Area [6] mapping and solar energy values used for calculation of the curtailment revenue.

Demand Region	LBNL Balancing Area	2023 Solar Energy Value (2025 US$)
NYISO	NYISO	32.26
ISO-NE	ISONE	31.93
CAISO	CAISO	23.11
ERCOT	ERCOT	71.46
PJM	PJM	33.5
MISO	MISO	34.7
BPA	BPAT	45.32
WAPA Rocky Mountain Region	WACM	22.78
Duke Energy Carolinas LLC	DUK	33.3
PacifiCorp East	PACE	32.53
Duke Energy Florida Inc	FPC	23.6
Southern Co Services Inc	SOCO	31.29
Florida Municipal Power Pool	FPL	32.88
El Paso Electric	ERCOT	71.46
Arizona Public Service Co	AZPS	27.92
Southwest Power Pool	SPP	35.42
Nevada Power Co	NEVP	29.1

Table S3. Plant to demand region mapping.

plant_name	state	demand_region
59th Street	NY	NYISO
A L Pierce	CT	ISO-NE
Agnews Power Plant	CA	CAISO
Alameda	CA	CAISO
Arthur Von Rosenberg	TX	ERCOT
Aurora	IL	PJM
Bergen Generating St	NJ	PJM
Big Cajun 1	LA	MISO
Bluegrass Generating	KY	PJM
Carty Generating Sta	OR	BPA
Chesterfield	VA	PJM
Cleveland Cnty Gener	NC	Duke Carolinas
Coyote Springs	OR	BPA
Coyote Springs II	OR	BPA
Decker Creek	TX	ERCOT
Donald Von Raesfeld	CA	CAISO
Doswell Energy Cente	VA	PJM
Fort Pierce Generati	UT	PacifiCorp East
Gianera	CA	CAISO
Gilroy Peaking Energ	CA	CAISO
Gilroy Power Plant	CA	CAISO
Gravel Neck	VA	PJM
Hermiston Generating	OR	BPA
Hermiston Power Part	OR	BPA
Hines Energy Complex	FL	Duke Florida
Hopewell Cogeneratio	VA	PJM
Inver Hills	MN	MISO
Kings Mountain Energ	NC	Duke Carolinas
Ladysmith	VA	PJM
Lamar Power Project	TX	ERCOT
Los Esteros Critical	CA	CAISO
Mariposa Energy Proj	CA	CAISO
Marsh Run Generation	VA	PJM
Metcalf Energy Cente	CA	CAISO
Midlothian Energy Fa	TX	ERCOT
Millcreek Power Gene	UT	PacifiCorp East
Minnesota River	MN	MISO
Morgan Creek	TX	ERCOT
Moxie Freedom Genera	PA	PJM
Mulberry Cogeneratio	FL	FMPP
Murray Turbine	UT	PacifiCorp East
Ocotillo	AZ	Arizona PSC
Orange Cogeneration	FL	FMPP
Panda Temple Power S	TX	ERCOT
Paris (WI)	WI	MISO
Paris Energy Center	TX	ERCOT
Potomac Energy Cente	VA	PJM
Remington	VA	PJM
St Joseph Energy Cen	IN	MISO
T H Wharton	TX	ERCOT
TVA Southaven Combin	MS	MISO
Tenaska Frontier Gen	TX	ERCOT
Tiger Bay	FL	Duke Florida
V H Braunig	TX	ERCOT
Victoria	TX	ERCOT
Victoria City Power	TX	ERCOT
Wallingford Energy	CT	ISO-NE

Supplementary References

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