How the U.S. Power Grid Kept the Lights on in Summer 2024

Paul Denholm,[1] Victor Duraes de Faria,[1] and Jason Frost[2]

1 National Renewable Energy Laboratory
2 U.S. Department of Energy

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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
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List of Acronyms

BTM	behind-the-meter
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
GW	gigawatt
ISO	independent system operator
ISO-NE	ISO New England
MISO	Midcontinent Independent System Operator
MW	megawatt
NERC	North American Electric Reliability Corporation
NG	natural gas
NPCC	Northeast Power Coordinating Council
PV	photovoltaics
SERC	Southeast Regional Council
SPP	Southwest Power Pool
SRA	Summer Reliability Assessment
WECC	Western Electricity Coordinating Council

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1 Introduction

Maintaining the reliability of the bulk power system, which supplies and transmits electricity, is a critical priority of electric grid planners, operators, and regulators. The demand for electricity is increasing to power data centers, electrification of transportation and other end uses, and more[1]—all while the generation mix is rapidly evolving and fossil fuel plants are being retired. In many regions of the country, the demand for electricity often reaches its highest (peak) levels during summer afternoons when high temperatures drive increased use of air conditioning. Increasing frequency of extreme heat events are also adding to the challenge of serving summer peak demand. In addition, an evolving generation mix with increasing renewables and storage and retirements of older fossil-fueled generators are changing how grid operators maintain reliable electricity supply through these events.[2]

The North American Electric Reliability Corporation (NERC)[3] issues annual assessments and forecasts for the upcoming winter and summer seasons; these risk assessments estimate expected demand levels and the availability of electricity generation to meet that demand during periods identified as having the highest risk of electricity supply shortfall. In its 2024 Summer Reliability Assessment (SRA), NERC identified five regions—illustrated in Figure 1—as having an elevated risk of an outage in "above-normal" conditions.[4] This means these regions faced risks of energy shortfalls under some combination of electricity demand at the highest end of projected ranges and historically high generation outages. The rest of the United States[5] was expected to have "normal" levels of risk.

[1] NERC Long-Term Reliability Assessment https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf
[2] This report focuses on the summer of 2024, but winter peaks can be higher in some regions and of growing concern in many other regions.
[3] NERC is an "international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid." https://www.nerc.com/AboutNERC/Pages/default.aspx
[4] NERC 2024 Summer Reliability Assessment https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf
[5] NERC's assessment does not consider Alaska or Hawaii, so this document only considers the conterminous (lower 48) states.

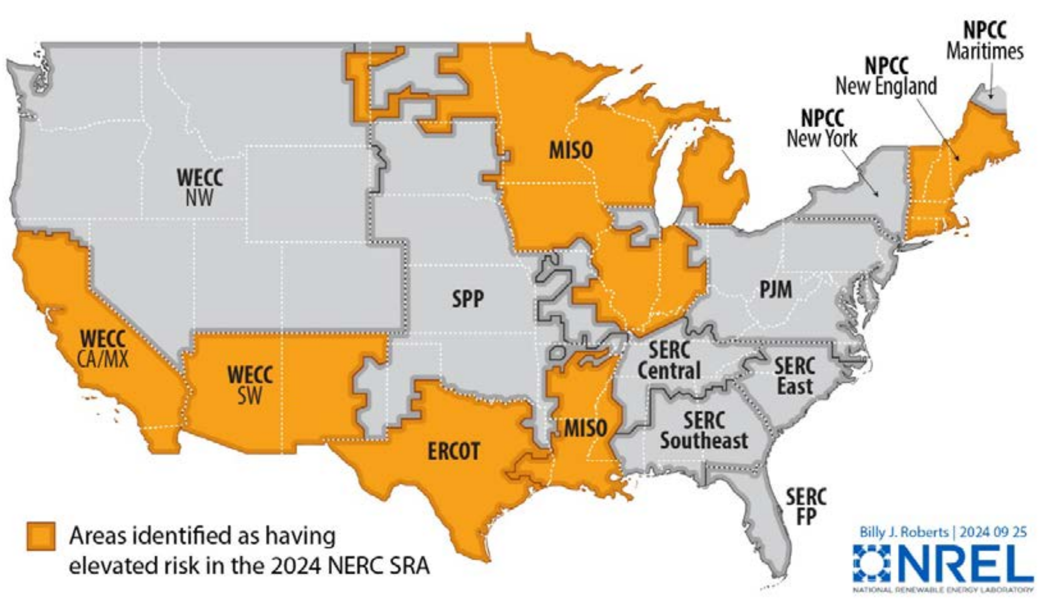

Figure 1. NERC risk assessment regions in the United States, highlighting five regions considered as having elevated risk in summer 2024

WECC = Western Electricity Coordinating Council; SPP = Southwest Power Pool; ERCOT = Electric Reliability Council of Texas; MISO = Midcontinent Independent System Operator; SERC = Southeast Regional Council; NPCC = Northeast Power Coordinating Council

Now that the 2024 summer season has ended and the data have been gathered, we can evaluate grid performance in these "elevated risk" areas of the country. Summertime temperatures in 2024 were above average,[6] driving high electricity demand. Several regions such as the Texas power grid came close to or hit record-high demand for electricity.[7]

Despite the high demand for electricity, there were no major outages caused by inadequate generation capacity. Although some consumers lost power because of localized events, the bulk power system—the network of generators and transmission lines—was able to supply sufficient electricity to keep the lights and air conditioners working.[8]

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[6] The period of June–August was 2.5°F above average. NOAA "U.S. Climate Summary for August 2024." https://www.climate.gov/news-features/understanding-climate/us-climate-summary-august-2024

[7] ERCOT. October 10, 2024. "Board of Directors Meeting Item 7: Summer 2024 Operational and Market Review." https://www.ercot.com/files/docs/2024/10/03/7-summer-2024-operational-and-market-review.pdf.

[8] This discussion focuses on the bulk power system which consists of generators and the high-voltage transmission network. During summer 2024, there were no significant outages because of failures or insufficient capacity on the bulk power system. Local outages that occurred (and most outages in general) were because of failures on the distribution system, which is the set of lower-voltage wires and systems that deliver electricity from the bulk power system to homes and businesses. NREL "Explained: Reliability of the Current Power Grid" https://www.nrel.gov/docs/fy24osti/87297.pdf

This report briefly describes how various regions in the U.S. power grid kept the lights on in summer 2024. It also highlights notable trends in the evolving grid mix that are helping maintain summer peak reliability in places such as Texas—and how these trends could help maintain future summer reliability in regions throughout the United States.

2 How Did They Do It?

Grid operators used a mix of resources to keep the lights on this summer. Notably, along with existing thermal (fossil and nuclear) and hydropower generation resources, increasing solar and storage resources contributed significantly during peak demand periods in some regions. This report places special attention on Electric Reliability Council of Texas (ERCOT) because it is one of the fastest-growing regions in the country,[9] it experienced near-record peak demand in the summer of 2024, and it shows how rapidly increasing solar and storage deployments can impact summer peak operations. We also examine several other regions that NERC identified as having elevated risk and that vary in deployment of solar and storage resources.

2.1 ERCOT

Figure 2 shows the maximum daily electricity load[10] in ERCOT (black line) from June 1 through September 12, along with the maximum daily population-weighted average temperature[11] (blue line) over the same period. Prior to August 1, the demand peaks were generally below 80,000 megawatts (MW). However, an extended period of hot weather began in early August, with a maximum peak demand on August 20.

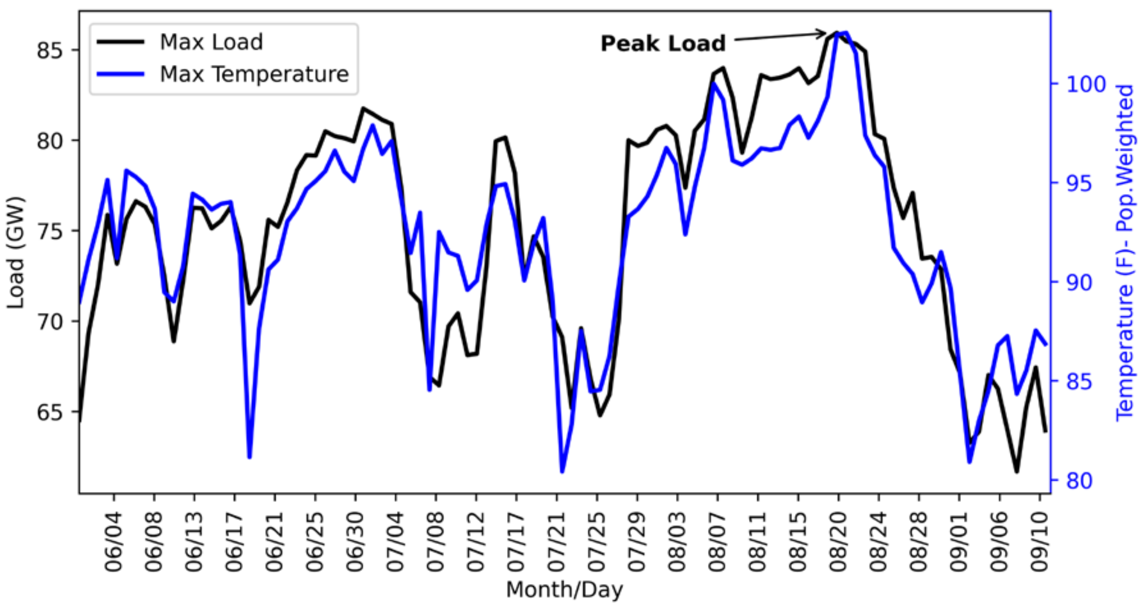

Figure 2. Maximum daily electricity demand (black) in ERCOT in summer 2024 was highest when peak temperatures (blue) averaged over 100°F in August

GW = gigawatts

[9] According to NERC's 2023 Electricity Supply and Demand report, ERCOT is projecting demand to grow 15% between 2022 (the last historical year included in the data) and 2026. This is faster than any other region, though load forecasts have continued to change since these data were released in December 2023.

[10] ERCOT load data from https://www.ercot.com/gridinfo/generation.

[11] We estimated the population-weighted average temperature across ERCOT using ZIP code level population from https://statics.teams.cdn.office.net/evergreen-assets/safelinks/1/atp-safelinks.html and temperature data from https://www.ncei.noaa.gov/pub/data/uscrn/products/subhourly01/.

Figure 3 zooms into August 20, the day with the peak demand. The average temperature across ERCOT hit about 102°F, with many regions experiencing higher temperatures. During the peak hour (4–5 p.m.), the average demand was 85,491 MW, with an instantaneous 5-minute peak of 85,931 MW. ERCOT was able to serve this load without generation-related shortfalls.[12]

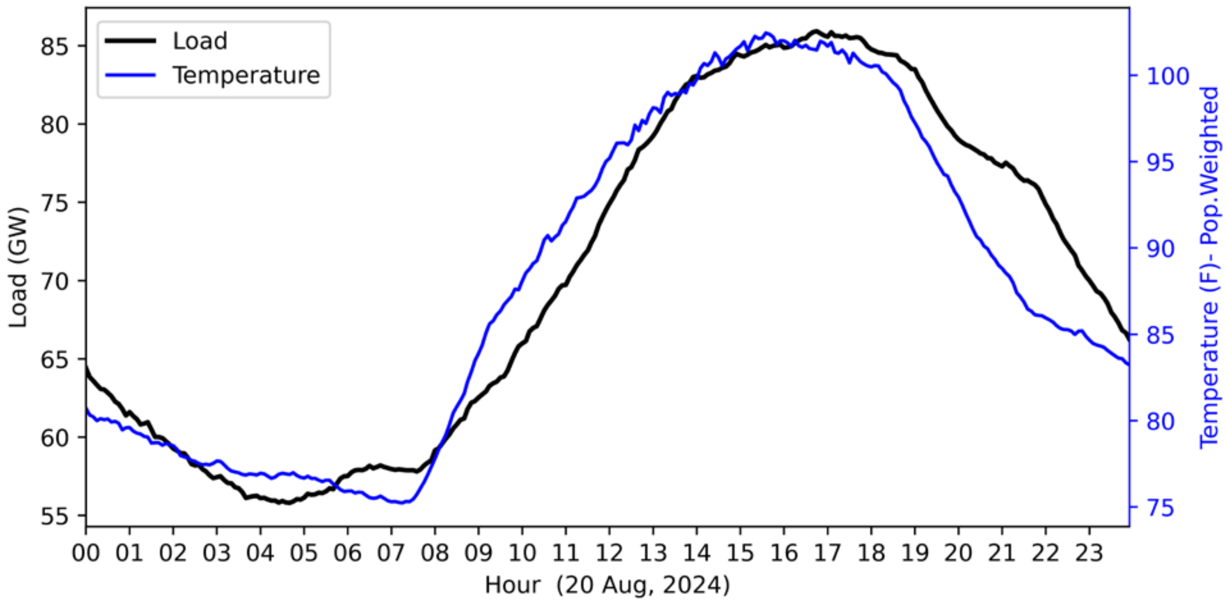

Figure 3. Demand profile and average temperature on August 20, 2024, showing near-record peak demand of more than 85 GW

Figure 4 illustrates the electricity generation by resource type that reliably met the electricity demand on August 20 in ERCOT.[13] Over this 24-hour period, about 66% of total generation was provided by fossil-fueled power plants, and these plants provided about 65% of generation during the peak hour. The remaining contribution was from low-carbon resources (renewables and nuclear). Utility-scale solar provided about 12% of the day's generation.[14] This solar generation had four impacts on the system's ability to serve demand, as illustrated in the figure and described next.

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[12] As noted previously, there were local outages because of failures on the distribution system. Utility Dive "ERCOT successfully navigates heat wave, new peak demand record" https://www.utilitydive.com/news/ercot-successfully-navigates-heat-wave-new-peak-demand-record/725197/

[13] Data from ERCOT. https://www.ercot.com/gridinfo/generation

[14] Generation data from ERCOT does not include the contribution of behind the meter solar. The load profiles shown are therefore net of the BTM solar. In the 8-month period ending in August of 2024, BTM solar provided about 3.3 TWh, compared to 26.0 TWh from utility-scale systems in all of Texas (not just ERCOT).

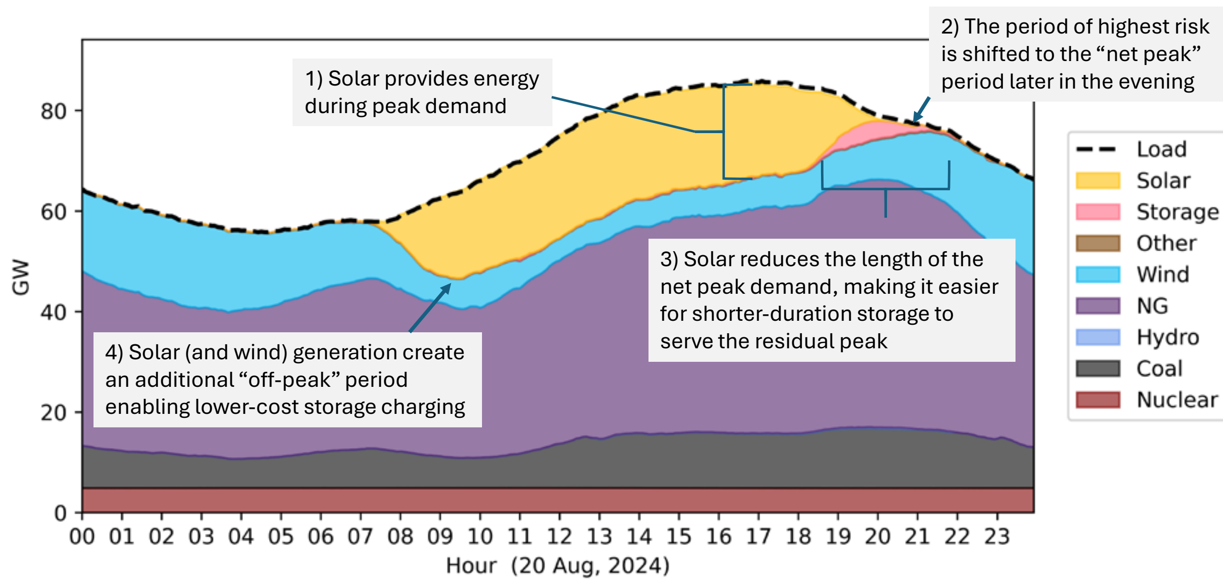

Figure 4. Generation resource mix on August 20, 2024, highlighting four impacts of solar on ERCOT's ability to achieve reliable operation

NG = natural gas

- **Solar significantly contributed to meeting peak demand.** During the hour of peak demand, solar generated at about 18 GW (generating at above 80% of its theoretical potential), providing about 21% of total generation. Solar's significant generation during the peak demand period reduced the risk of an outage during this period and therefore the amount of generation capacity needed from other sources to maintain reliability.
- **Solar shifted the period of highest risk to the evening.** Because of the significant solar generation during the period of highest demand, the period of highest risk was shifted to later in the evening. This shift is often characterized by examining the "net demand" defined as normal demand minus the contribution of certain renewable resources (typically solar or solar plus wind). The peak net demand (net peak) therefore represents the maximum instantaneous generation required from nonrenewable generators and storage. During the 5-minute period of the absolute peak (85.9 GW at 4:45 p.m.), solar generation reduced the net demand to 67.2 GW. This is substantially lower than the day's peak net demand of 78.6 GW, which occurred at 7:55 p.m., when solar output had dropped to near zero.[15]

  This shift in the net demand period increased the probability of wind being available during net load peaks.[16] Wind often has a significantly lower-than-average availability

[15] Historically, NERC forecasts the hour of peak demand (which typically occurs between 3 and 5 p.m.) to estimate system risk. However, in some systems with significant solar (such as ERCOT and California), NERC now forecasts the net peak (removing the contribution of solar) as the period of highest risk. NERC 2024 Summer Reliability Assessment

[16] Harrison-Atlas et al. "Temporal complementarity and value of wind-PV hybrid systems across the United States" https://doi.org/10.1016/j.renene.2022.10.060

during summer afternoon peaks.[17] It provided only about 6 GW to the ERCOT grid during the period of absolute peak, despite an installed capacity of about 38.7 GW. Wind generally has higher availability in the evening, as shown previously in Figure 4 and later in Figure 9.

- **Storage provided a meaningful contribution to the net peak demand, enabled by solar generation.** Although solar by itself did not reduce the net peak demand past sunset, it changed the shape of the net peak period by making it shorter. Figure 5 shows this by comparing the total load (black line) and the net load after the contribution of solar was removed (dotted black line). This allows shorter-duration (and less-costly) storage to provide reliable capacity. Storage in ERCOT provided as much as 3.9 GW (about 4%–5% of total generation) during this period.

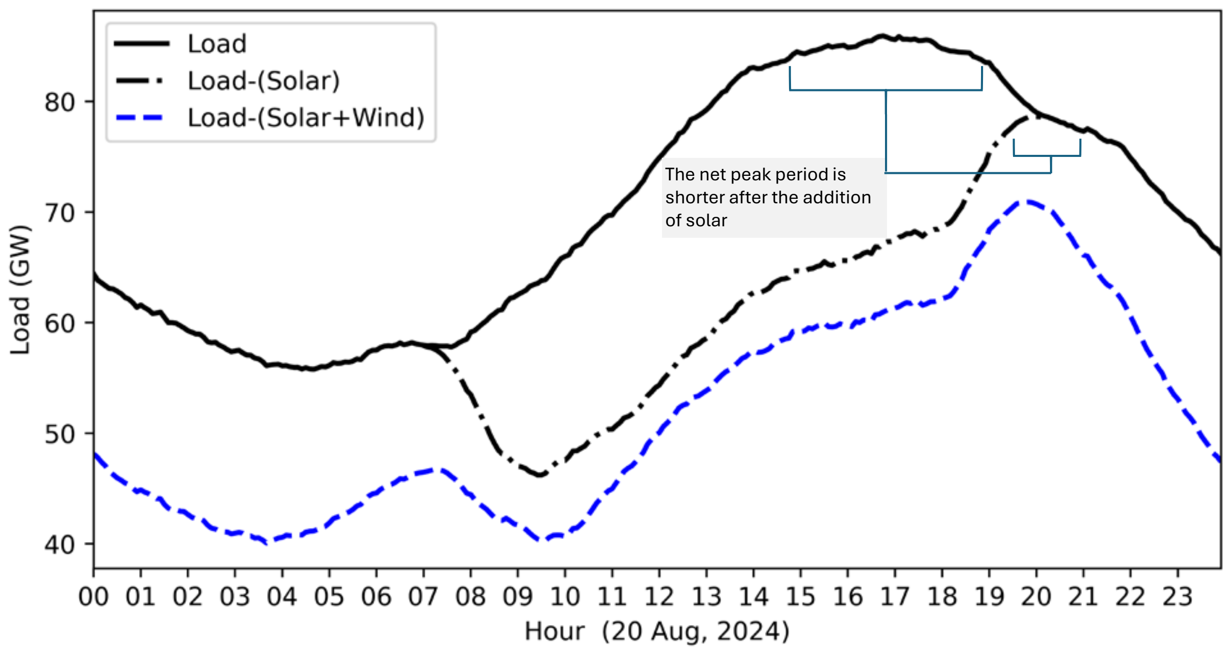

Figure 5. Solar reduces the length of the net peak demand period, reducing the duration of storage required while also increasing the amount of "off-peak" energy available for storage charging.

- **Solar (and wind) increased the availability of off-peak energy for storage charging.** Most recently deployed batteries have relatively short duration (4 hours or less) and generally must recharge every day to provide reliable capacity during extended periods of hot weather. During periods of high temperatures, nighttime demand often stays relatively high. Although there is plenty of spare thermal capacity (coal and gas) for recharging, storage may be forced to purchase power at prices set by relatively high-priced generators. However, solar generation in the late morning and wind overnight reduced the net demand, creating longer or "deeper" off-peak periods as shown in

[17] NERC 2024 Summer Reliability Assessment

Figure 5 (with the net load including wind, shown in blue)—which allowed lower-cost charging from existing thermal units.[18]

Overall, during the peak summer period in 2024, ERCOT met demand with a combination of legacy resources (natural gas and other thermal resources) and the more recent additions of solar and energy storage. The contribution of solar and storage will continue to grow as more of these resources are deployed. As of September 2024, utilities and developers in Texas have added (cumulatively) about 19 GW of solar and 5 GW of batteries, mainly in the last few years, as shown in the solid bars in Figure 6.[19] That is still much less than the 67 GW of natural gas and 14 GW of coal, with installations that date back to before 1960.

Figure 6 also shows estimates of future capacity additions, including those that have been completed as of August 2024, or are under construction or in various stages of approval. The continued growth of both solar and storage is expected to supply an increasing fraction of demand on hot summer afternoons and evenings.[20]

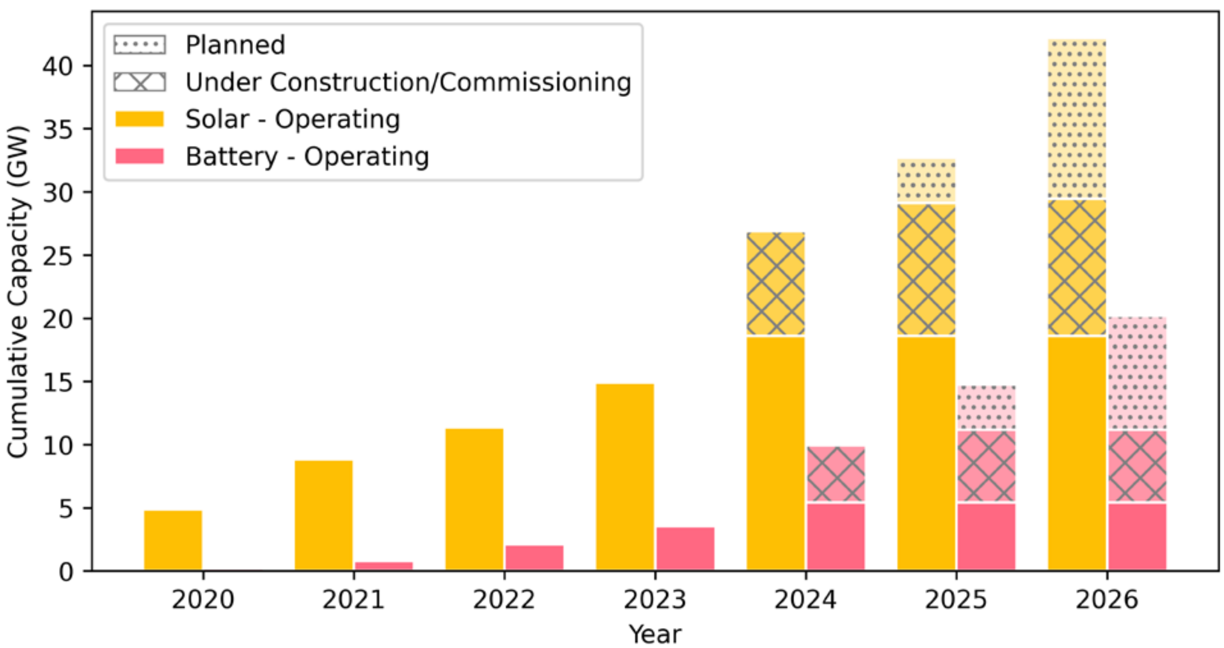

Figure 6. Cumulative solar and storage deployment in ERCOT shows significant growth since 2020 with further growth expected

Values for 2024 are as of August from EIA 860m

[18] The overall change in shape of the net load that results from significant solar deployment is characterized by a low net demand in the middle of the day, and a rapid increase in net demand towards sunset. The resulting shape is sometimes referred to as the duck curve. https://www.nrel.gov/docs/fy16osti/65023.pdf
[19] EIA Form 860m data https://www.eia.gov/electricity/data/eia860m/
[20] NREL Standard Scenarios. https://www.nrel.gov/analysis/standard-scenarios.html

2.2 Other Regions

In other parts of the country, demand on peak days was met by different mixes of legacy thermal, hydropower, renewable, and storage resources, often supplemented by imports from other regions via transmission. However, many regions are now seeing significant contributions from solar.

Although some regions like ERCOT only report utility-scale solar generation, contributions from solar include both utility-scale and behind-the-meter (BTM) systems. The actual contribution from BTM solar toward meeting peak demand can be difficult to determine because it is often not reported. However, some regions report estimated BTM solar generation, and the significant role of BTM solar can be observed in the ISO New England (ISO-NE) region—which corresponds to NERC's NPCC-New England region.[21] Figure 7 shows the generation mix on the peak day (July 16), highlighting the contributions from both BTM and utility-scale solar. Notably, most of New England's solar is in the form of BTM, which was able to provide about 12% of the system generation during the peak demand hour, with utility-scale solar contributing an additional 2%.

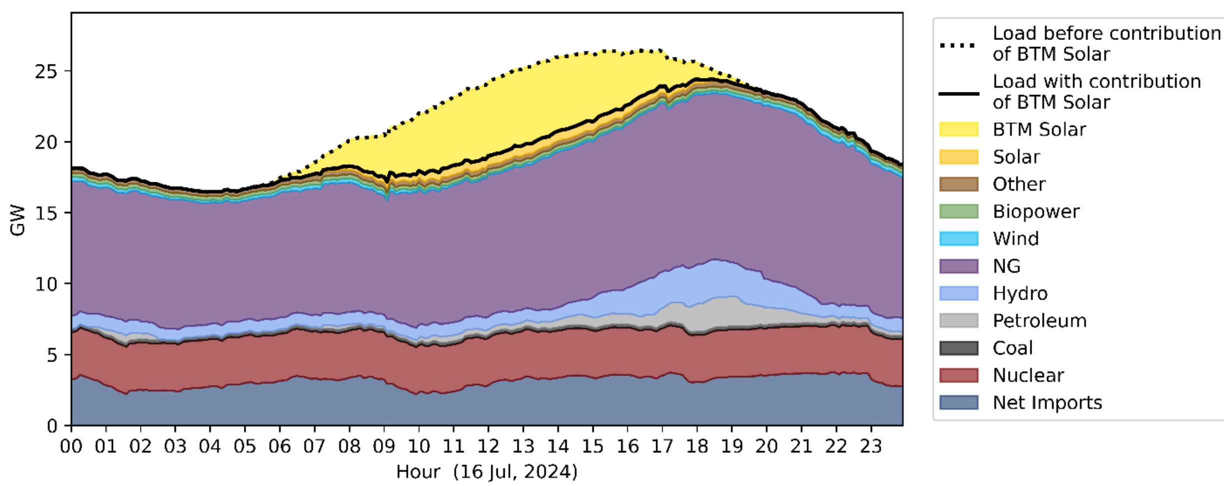

Figure 7. Generation resource mix on July 16, 2024, in the ISO-NE region, showing the large contribution of behind-the-meter solar

The figure also shows the significant role of dispatchable hydropower as well as electricity imports from other regions. New England is also one of the few regions of the country that relies on oil-fired peaking units. These units are operated relatively infrequently because they have high fuel costs and are among the most expensive to operate.

Although ERCOT has primarily utility-scale solar and New England has mostly BTM solar, California has large quantities of both. This solar capacity provided a significant benefit during California's peak demand day on September 5.

[21] https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type

Figure 8 shows the generation mix on the peak day for the California ISO (CAISO) area, which corresponds to about 80%[22] of California's electricity demand.[23] Only utility-scale solar is shown, but CAISO reported more than 15.7 GW of BTM solar in its system in addition to the more than 18.5 GW of utility-scale solar in 2024.[24] The presence of BTM solar is reflected in the load shape, which would include more load in the middle of the day in the absence of BTM solar, and shifts the load peak to later in the day, even before the contribution of utility-scale solar.

During the peak hour, about 24% of CAISO's demand was met by utility-scale solar.[25] The resulting net load after the contribution of solar (lower dashed line) creates a steep but short net peak that can be cost-effectively met with energy storage, with its ability to rapidly increase output.[26] During the hour of peak net demand, storage provided about 13% of total generation, with the remainder provided by natural gas, hydropower, imports, and other resources including wind.[27] Figure 8 also shows the significant storage charging occurring in the early morning and during the late morning off-peak period. This off-peak period is a result of substantial solar generation occurring before the afternoon increase in demand as previously shown in Figure 4 and Figure 5.

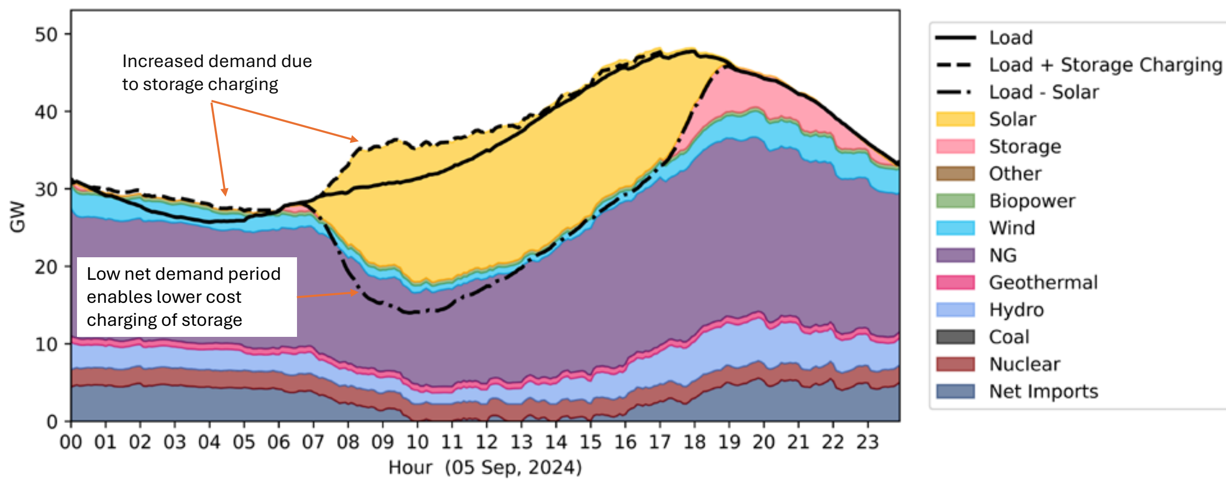

Figure 8. Generation resource mix on September 5, 2024, in the CAISO region, showing the large contribution of solar and storage toward meeting peak demand

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[22] CAISO Key Statistics September 2024 https://www.caiso.com/documents/key-statistics-sep-2024.pdf
[23] Data from https://www.caiso.com/todays-outlook/supply. Although NERC's SRA evaluated the slightly larger WECC-CA/MX region, complete data for that region is not publicly available.
[24] https://www.caiso.com/documents/april-8-solar-eclipse-technical-bulletin-march-11-2024.pdf
[25] Because of the shift in peak load caused by BTM solar, utility-scale solar output has already begun to drop. In the hour of peak demand, utility-scale solar is generating at about 38% of rated capacity and dropping rapidly.
[26] NREL Storage Futures Study Key Learnings for the Coming Decades https://www.nrel.gov/docs/fy22osti/81779.pdf
[27] In addition to having more storage capacity (by power) than ERCOT, California's storage tends to have more energy (duration) per unit of power capacity. For a discussion of drivers behind regional duration, see https://www.nrel.gov/docs/fy23osti/85878.pdf.

In other parts of the country, such as those served by MISO, there is relatively less installed solar and storage capacity, so the solar and storage share of peak day generation was significantly lower than in regions such as Texas, New England, and California. Peak demand in these other areas was reliably met largely with thermal generators and with smaller contributions from hydropower, solar, and wind. Figure 9 provides an example of the generation mix in MISO on the peak demand day on August 26.[28] Compared to the other regions examined above, MISO remains more dependent on natural gas and coal generation. Regions like MISO have significant opportunity to deploy more solar and storage to help meet summer peak demand in the future.[29]

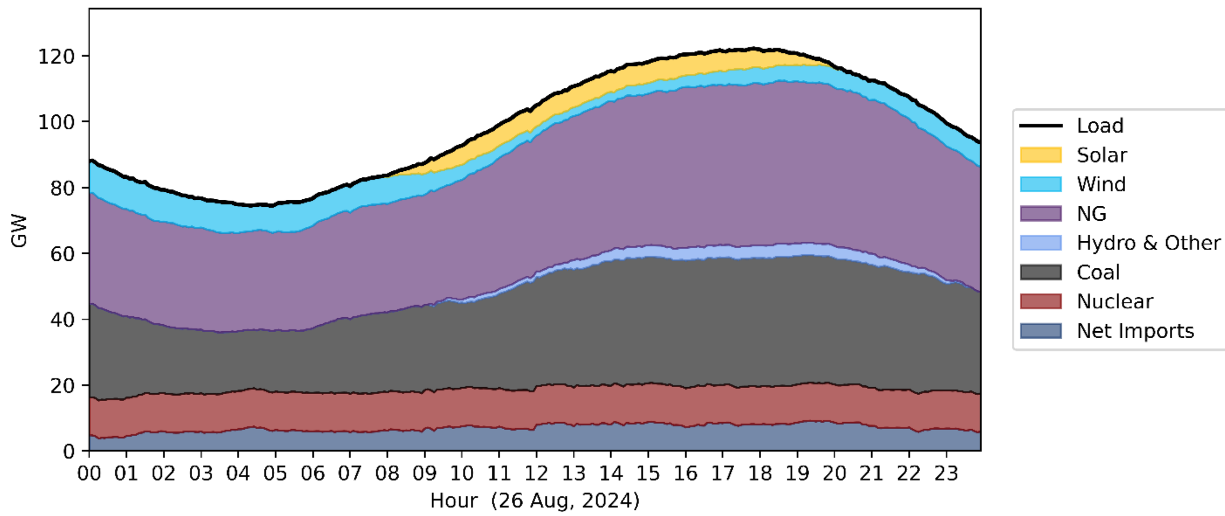

Figure 9. Generation resource mix on August 26, 2024, in the MISO region, showing limited contribution from solar and other low-carbon resources

[28] https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-report-archives/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc
[29] Frazier et al. Assessing the potential of battery storage as a peaking capacity resource in the United States. https://www.sciencedirect.com/science/article/pii/S0306261920308977

3 Maintaining Reliability During Future Summer Peaks

Both the supply and demand of electricity are changing quickly. Demand is growing to power data centers and an expanding digital economy, a U.S. manufacturing renaissance, and the electrification of transportation and other end uses[30]—all while the generation mix is rapidly evolving. Historically, the grid has primarily relied on thermal and hydropower resources to keep the lights on during summer peaks. But increasingly rapid deployment of grid-scale solar and storage are enabling these technologies to play a larger role.[31]

Summer 2024 demonstrated the combined ability of solar and storage to provide valuable capacity during summer peaks in diverse regions across the country, including Texas, California, and New England. Greater solar output increased the availability of clean generation during hot summer afternoons, shortened net peaks, and shifted those peaks to the evenings. As the sun set, grid-scale battery storage played a crucial role by discharging stored energy that helped maintain grid reliability until cooler temperatures reduce loads overnight.

The performance of the Texas and California power grids in summer 2024 showed that solar and storage can work together to help power the grid through peak summer demand days. Storage with relatively short duration (2–6 hours) can provide a significant portion of summer peak demand in all regions of the United States.[32]

3.1 Projected Solar and Storage Growth

In the coming years, even more solar and storage is planned to be connected to the grid. Figure 10 shows projections from the Energy Information Administration (EIA) with estimates of more than 140 GW of grid-scale solar installed in the United States by the end of 2025, compared to 109 GW as of August 2024. [33] These data also project grid-scale battery storage will grow from 22 GW to 38 GW over the same time frame. There is also a large amount of solar and storage resources waiting in interconnection queues planned for installation beyond 2025. Based on these trends, solar and storage will likely have a growing role in keeping the lights and air conditioning working on the hottest summer days in more regions across the country.[34]

[30] Wood Mackenzie projects data centers will add 25 GW of new demand, manufacturing will add 15 GW, electrification will add 7 GW, by 2029. [US utilities to face significant challenge as power demand surges for the first time in decades | Wood Mackenzie]. Grid Strategies also identifies data centers, large industrial loads, and electrification as key drivers of growing demand: [National-Load-Growth-Report-2023.pdf (gridstrategiesllc.com)].
[31] Denholm, P. *Explained: Maintaining a Reliable Future Grid with More Wind and Solar*. National Renewable Energy Laboratory. NREL/FS-6A40-8729 https://www.nrel.gov/docs/fy24osti/87298.pdf
[32] Blair, N., et al. *Storage Futures Study: Key Learnings for the Coming Decades*: National Renewable Energy Laboratory. NREL/TP-7A40-81779
[33] Data includes Alaska and Hawaii. EIA 860m https://www.eia.gov/electricity/data/eia860m/
[34]https://emp.lbl.gov/queues

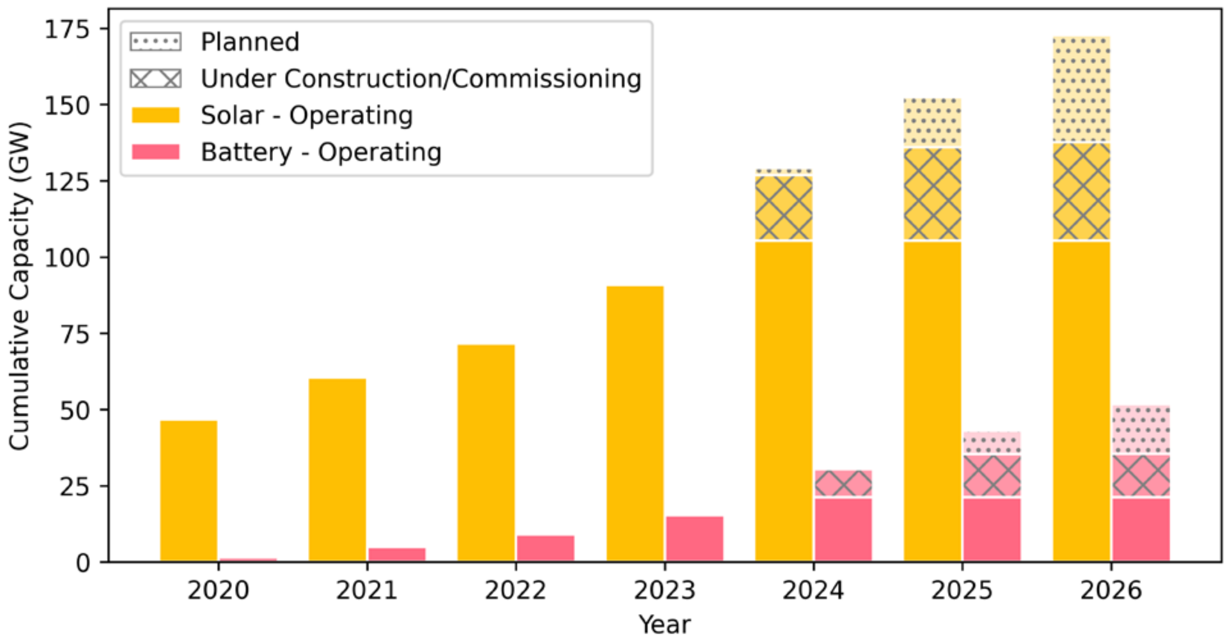

Figure 10. National projections from the EIA show substantial near-term growth of both solar and battery storage is expected

Values for 2024 are as of August from EIA 860m

3.2 Evolving Challenges and Opportunities

Leveraging the capabilities of diverse generation resources can improve reliability. Each resource type can serve specific needs, enabling the combined portfolio to provide consistent reliable power during peak hours. The power grid will never rely solely on solar and storage to meet all system needs. As load changes, so will the resource mix. In the near term, thermal resources will continue to play a critical role in meeting demand, including during system peaks, though their utilization is expected to decline as solar, storage, and wind resources grow.

The integration of more diverse generation resources involves changing the processes used to ensure sufficient generation capacity is available to serve demand at all times.[35] Historically, planners have forecast peak loads and maintained nameplate generation capacity equal to that peak load plus a reserve margin to cover outages and forecast uncertainty. As more renewable and storage resources connect to the bulk power system, different resources provide different combinations of services or value to the grid. This can cause the hours during which the grid is most stressed to shift to later in the day during the summer, as has happened with growing solar deployment in Texas and California, as well as to periods of low solar output in the winter. In the future, it will be increasingly important for grid planners and operators to consider other possible periods of grid stress in addition to summer peaks.

[35] ESIG Redefining Resource Adequacy for Modern Power Systems https://www.esig.energy/resource-adequacy-for-modern-power-systems/

In this context, more sophisticated probabilistic analysis that evaluates contributions of all resources during times of greatest system stress is needed to ensure the resource mix can serve total demand in both summer and winter as load grows, demand patterns shift, and the role of renewable generation increases.[36] Many grid operators have recently implemented or are currently implementing such approaches.[37] Careful and rigorous planning and additional improvements to planning frameworks is important to ensure continued reliable system operation.

Alongside solar, storage, and wind, other clean resources can bring a variety of benefits to the power system in future summers. These resources include supply-side technologies such as nuclear, geothermal, and long-duration storage that can provide power during periods of greatest system need. They also include transmission infrastructure to bring power to where it is needed most, connect new resources to loads, and improve power system resilience to extreme weather. Innovative demand-side technologies can play an important role, too, enabling consumers to implement grid-edge solutions that reduce peak demands and serve as virtual power plants while reducing customer and system costs.[38] The Bipartisan Infrastructure Law[39] and Inflation Reduction Act[40] are investing tens of billions of dollars into demonstrating and deploying this suite of new technologies. At the same time, the Federal Energy Regulatory Commission is reforming transmission planning and interconnection processes to facilitate the market entry of new resources.[41,42] With continued rigorous planning, these new resources can build on the value that thermal plants, hydropower, solar and storage, and wind are already providing to keep the power system operating smoothly during both summer peaks and other future periods of grid stress.

[36] DOE. The Future of Resource Adequacy. 2024 The Future of Resource Adequacy Report.pdf (energy.gov)
[37] PJM adopted a marginal ELCC capacity accreditation framework for its 2025-2026 capacity auction: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false. ISO New England is developing a Marginal Reliability Impact accreditation framework that it plans to implement beginning June 1, 2028: https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.
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