

Impacts of Distributed Energy Generation on the State's Distribution and Transmission Grid

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Legislative Report on the Impacts of Distributed Energy Generation on the
State's Distribution and Transmission Grid
California Public Utilities Commission

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EXECUTIVE SUMMARY

Since 2008, installed behind-the-meter (BTM) solar capacity in California has grown from 354 MW to 3,572 MW, and as of December 2015 was installed at 456,000 residential sites and 10,300 commercial sites statewide. BTM solar capacity continues to increase, due to a combination of federal and state incentives¹ and rapidly falling cost of solar. Benefits of solar power include its low lifecycle emissions of CO₂ and other air pollutants as well as its ability to lower California's peak electricity demand in the summer, thereby avoiding the dispatch of high-emitting, costly peaker plants.

Increased solar capacity, however, contributes to changes in daily patterns of net load that result in challenges as well as benefits to the power grid.² At sufficiently high penetrations, solar power produces a "duck curve" pattern in daily net load³, in which net load dips during peak solar output in the middle of the day and then rises sharply in the early evening. In the winter and spring, this can result in over-supply of power in the middle of the day and require large amounts of fast-acting resources (such as gas plants, batteries, or demand response) to ramp up quickly as the sun sets and solar power production drops.

This report uses 2014 data to quantify the effects of BTM solar production on daily net-load patterns in California. In 2014, installed BTM solar capacity was 1,270 MW in PG&E and 1,130 MW in SDG&E and SCE combined. For comparison, the peak output of CAISO grid-scale solar in 2014 was 1,050 MW in northern California (slightly less than BTM solar capacity in PG&E) and 3,230 MW in southern California (nearly triple the BTM solar capacity of SDG&E and SCE). 2014 average load was 12,000 MW for PG&E and 14,500 MW for the combination of SDG&E and SCE.


This report analyzes the impacts of BTM solar capacity given 2014 historical data, and its findings apply to the 2014 system and to near-future scenarios that are similar. In particular, the report does not consider longer-term developments such as large-scale deployment of energy storage, effective time-of-use incentives, or smart EV charging, all of which could aid in the integration of large amounts of solar capacity. A recent CPUC whitepaper⁴ provides full context for the technical, economic, market, and policy issues surrounding the long-term integration of large amounts of renewables, discusses portfolios of solutions for addressing these challenges, and finds that renewables integration is achievable if it is given sufficient priority. This contribution of this

¹ Including the California Solar Initiative (CSI), and Net Energy Metering.

² In this report, net load is defined as the difference between load and solar power output, and it represents the amount of power that other generators or demand response must provide in order to balance supply with demand.

³ https://www.aiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

⁴ California Public Utilities Commission (CPUC), 2015. "Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future."



legislative report is to identify trends in the effects of BTM solar in California to help inform grid integration strategies.

Major findings on the effects of BTM solar in the current system are:

- **BTM solar is effective at reducing summer peak net load and is changing net-load shapes in the winter and spring (Section 3.3).**
 - While solar power output peaks midday, summer load peaks at around 17:00. Because of this, BTM solar reduced summer peak net load by about 500 MW (2.6 % of the 20,000 MW peak) for PG&E and 400 MW (1.4 % of the 25,900 MW peak) for SDG&E/SCE combined, an effect amounting to less than half of the installed BTM solar capacity (1,270 MW in PG&E and 1,130 MW in SDG&E/SCE). When the effects of grid-scale solar are included, results show that additional solar capacity will have a limited effect on reducing summer peak net load further (given current daily load shapes).
 - BTM solar does not reduce winter and spring peak net load.
 - At current penetrations, solar PV (grid-scale and BTM) has no effect on minimum net load⁵ in the north (PG&E service territory), but it has reduced winter minimum net load in southern California by approximately 2,000 MW and shifted the time of minimum net load from the early morning to after sunrise. If minimum net load drops sufficiently low, base-load generators such as coal, gas, and nuclear plants may be unable to reduce their power production enough to match it (resulting in over-supply of power). This situation will require re-shaping of daily net load patterns to shift more energy consumption to hours of high solar power output.
 - In spring and winter months, grid-scale and BTM solar are increasing the magnitude and duration of the afternoon net-load ramp. The hour with the highest net-load ramp rate occurs after the sun sets, although increased solar capacity would increase ramp rates during afternoon hours of solar production.

There are tradeoffs in the effects of west-facing and south-facing BTM solar (Sections 3.4 and 3.5). Major findings are summarized in

⁵ Minimum net load is defined as the minimum of hourly load minus hourly solar power output.


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- Table 1. These findings alone do not support policy to incentivize one type of solar over the other. Further study is needed to quantify the relative costs and benefits of west-facing and south-facing solar, both for the current system and future high-renewables scenarios.

Table 1. Summary of results comparing west-facing and south-facing BTM solar PV. All results pertain to 2014 load patterns and do not consider the effects of solar integration strategies.

	West-facing BTM PV	South-facing BTM PV
Primary characteristics	<ul style="list-style-type: none"> Comprises about 15 % of BTM solar installations. Power production peaks in the early- to mid-afternoon. 	<ul style="list-style-type: none"> Comprises about 77 % of BTM solar installations. Power production peaks mid-day to early afternoon.
Comparative advantages	<ul style="list-style-type: none"> Produces approximately 40% more energy during summer high-demand hours. This displaces energy production by high-emitting, less-efficient fossil-fueled peaking plants more effectively. Contributes to more consistent solar power production throughout the day (given the current prevalence of south-facing solar). 	<ul style="list-style-type: none"> Power production drops 50% more slowly in challenging spring and winter afternoon hours. This creates less need for fast-ramping resources (primarily gas in the current system). Contributes less to the potential for over-supply of power in the winter (when over-supply is an issue). Has a theoretically higher capacity factor, meaning it produces more energy on an annual basis.

- BTM solar in southeast California, on average, produces more energy with less variability than BTM solar in northwest California, indicating higher-quality solar power output in the southeast (Section 3.6).**
 - Like south-facing solar, BTM solar in southeast climate zones contributes less to the afternoon net-load ramp than solar in the northwest part of the state.
 - Like west-facing solar, BTM solar in northwest climate zones produces more energy during high-demand afternoon hours.


- **Correlation⁶ of different types of renewable generation indicates the benefit of a diverse portfolio of renewables (Section 3.7).**
 - The correlation between all types of solar and wind power output is negative, demonstrating a significant smoothing benefit from the combination of wind and solar power.
- **Large-scale deployment of energy storage, dispatchable demand-response, and time-of-use rates for consumers will help integrate increasing amounts of BTM solar PV. Further study is needed to determine the portfolio of grid integration solutions that best ensures environmental quality, cost-effectiveness, and grid reliability.**
 - As renewables penetration continues to increase, it will increase the value of storage and in turn incentivize its deployment. Wholesale market prices and utility tariffs, particularly demand charges on commercial customers, incentivize a shift in net load from its early evening peak to mid-day. Further analysis is needed to quantify the environmental and economic effects of these strategies.
 - The costs and benefits of south-facing and west-facing BTM solar should be quantified from a system-wide perspective to guide policy, both for the current system and for future scenarios in California's energy transition.

These results highlight the benefits of BTM solar but also point to challenges it could present as capacity increases. In particular, results indicate a tradeoff between west-facing and south-facing BTM solar. West-facing solar has had the significant advantage of reducing summer peak load more effectively than south-facing solar installations (it produces more energy during high-demand afternoon hours). However, as installed BTM and grid-scale solar capacity increases in California, net load will peak after the sun has set. In this scenario, the advantage of west-facing solar over south-facing solar will be diminished, and the grid will require additional interventions to shift load to hours of higher solar power production to decrease peak net load further.

In the winter and spring, when daily load shapes are different than in the summer, west-facing solar exacerbates the afternoon net-load ramp rate more than south-facing solar. Given much higher solar penetration, west-facing solar may add to the problem of winter over-supply more than south-facing solar.

In the current system, while solar capacity is low compared with its potential in the coming years and while California continues to have access to large amounts of quick-ramping gas capacity, the incremental benefits of west-facing solar capacity (peak net-load reduction) may outweigh those of south-facing solar. However, as solar penetration increases and flexible thermal capacity retires, the disadvantages of west-facing solar

⁶ Low correlation is desirable because it means that the fluctuations in the output of different renewable power plants tend to smooth one another out; high correlation implies that the fluctuations exacerbate each other.



may begin to outweigh the advantages. These results point to the need for further quantitative studies, and periodic re-evaluation, to determine the relative benefits and costs of south-facing and west-facing solar in the current and future grid. A combination of west-facing and south-facing solar would provide the most consistent power output throughout the day, and should also be analyzed further for future high-renewables scenarios.

The results of this study apply to the current system and do not account for other factors or policy interventions that could alter the impacts of BTM solar power on net load. Designing rates to incentivize a shift in electricity demand to peak solar hours, and adopting storage at a large scale to re-shape daily demand profiles to better align with solar power production, are examples of options to help integrate large amounts of solar power that are not considered in this report.

1 INTRODUCTION

Assembly Bill 578 (Blakeslee, 2008) requires the California Public Utilities Commission (CPUC) to submit a biennial report to the Legislature on the impacts of distributed generation on the state's distribution and transmission grid. In 2013, the CPUC contracted Black & Veatch to prepare the "Biennial Report on Impacts of Distributed Generation" and Itron to prepare an Impact Evaluation of CPUC's Self Generation Incentive Program. In 2015, since the CPUC does not expect the major conclusions from these reports to have changed in the past two years, Energy Division staff directed DNV GL to specifically examine how customer BTM PV impacts net-load patterns. In preparation of this report, DNV GL used the following sources of data:

- Net Energy Metering (NEM) Currently Interconnected Dataset⁷ (as of August 2015) to summarize the general growth and trends of BTM solar
- Itron fifteen-minute profiles from 289 metered BTM solar sites in 2014 to extrapolate the aggregate effects of BTM solar
- Historical hourly data for utility-scale solar energy output from the CAISO OASIS database to differentiate the impacts of BTM solar and grid-scale solar
- Metered load data from the CAISO OASIS database to provide a baseline for analyzing the impacts of BTM and utility-scale solar
- California Solar Initiative (CSI)⁸ database to analyze the effects of system azimuths on net-load patterns

⁷ The Currently Interconnected Data Set provides a full view of all interconnected solar PV (NEM) systems within PG&E, SCE, and SDG&E service territories. This dataset excludes pending and decommissioned projects.

⁸ The CSI program is a solar rebate program for ratepayers in California's IOU territories. The goal of the program is to install 1,940 MW of new solar by the end of 2016. It offers a declining rebate based on capacity installed by customer class and IOU territory. CSI represents 49% of BTM solar interconnected to the three IOUs.

Due to data availability, this report only analyzes load and solar impact in the CAISO system. It does not include publicly-owned utilities, such as Los Angeles Department of Water and Power (LADWP) or Sacramento Municipal Utility District (SMUD).

2 GROWTH OF BTM SOLAR IN CALIFORNIA

BTM solar capacity continues to grow quickly throughout California. Figure 1 shows cumulative installed capacity in the NEM Currently Interconnected Dataset as of August 2015, illustrating consistent growth for all three IOUs and a nearly even split between northern California (PG&E) and southern California (SCE and SDG&E).

Production profiles of BTM solar differ by azimuth, as analyzed further in Section 3. Figure 2 shows trends in the azimuths of newly interconnected installations in the CSI database by year (here, azimuth is defined by 90-degree increments—e.g., south-facing implies azimuths between 135 degrees and 225 degrees). The CSI database was used due to lack of azimuth data in the NEM Currently Interconnected Dataset for sites that were interconnected prior to 2015. The CSI database contains 49 % of the number of entries in the Currently Interconnected dataset.

In each year, the majority of the incremental BTM capacity in the CSI database was south-facing. Installed capacity of west-facing solar grew in the years up to 2013, before declining again through 2015. Capacity of tracking solar followed a near-opposite pattern, shrinking steadily through 2014 before growing again in 2015.

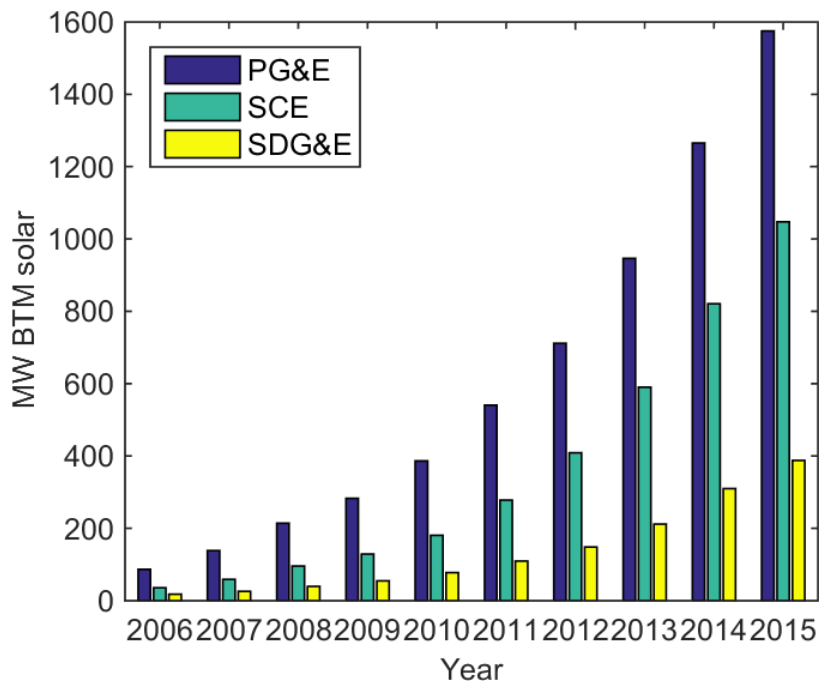


Figure 1. Cumulative BTM solar capacity in the NEM Currently Interconnected database over time.

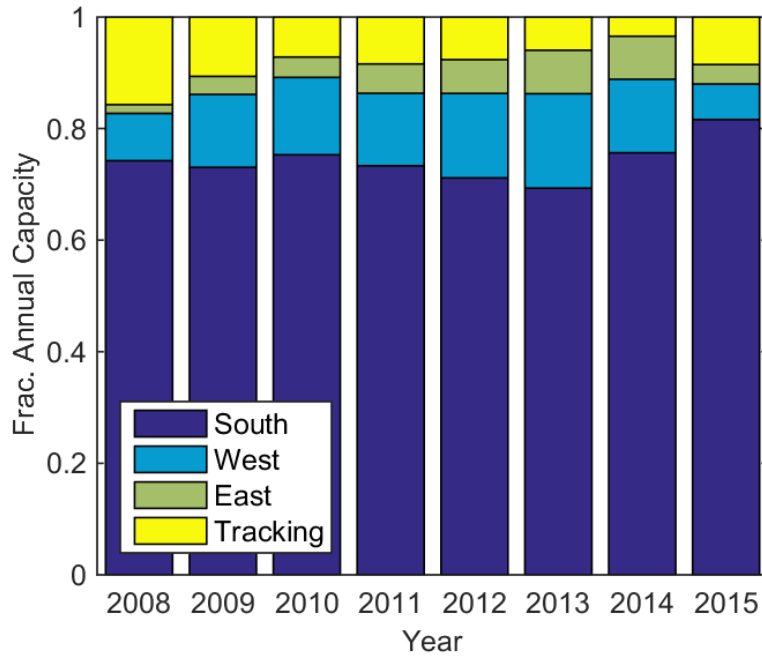


Figure 2. Fraction of tracking solar and fixed solar (categorized by orientation) installed each year. The label “Tracking” refers to both single-axis and dual-axis. This figure shows incremental (not cumulative) data.

BTM solar capacity is becoming more geographically concentrated. Figure 3 shows installed capacity by zip code from 2009 through 2015, indicating a growing number of zip codes in central California with more than 9 MW of capacity currently interconnected.

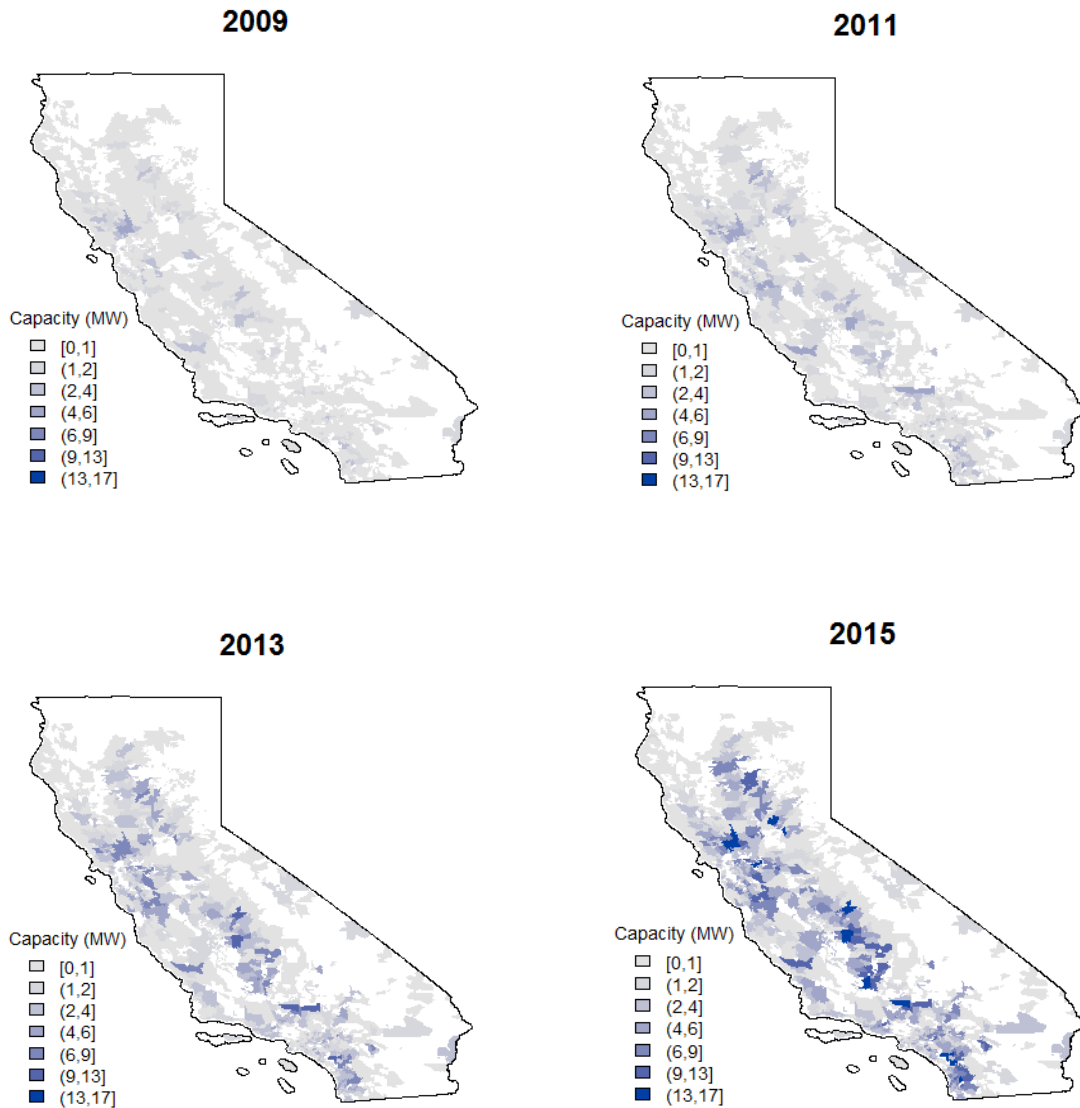


Figure 3. Growth of BTM solar in California, by zip code, from 2009 to 2015.

3 THE EFFECT OF BTM SOLAR ON CURRENT NET-LOAD PATTERNS

Due to contrasting daily load and solar production patterns at different times of year, the effect of solar PV on net load was analyzed for March, July, and December. These months are broadly representative of spring, summer, and winter net-load patterns in California.

3.1 Data and methods

Metered load data, which includes the effect of BTM PV, was obtained from CAISO for the three major IOUs.

Fifteen-minute profiles for BTM solar were obtained from Itron for a subset of the sites in the NEM Currently Interconnected Database. The profiles were generated by meters that Itron installed in 2010 at randomly selected sites in order to obtain a statistically significant sample of CSI sites (beyond that available from EPBB system data).⁹ Figure 4 shows the locations (by zip code) of all currently interconnected sites (black) as well as those with Itron profiles associated (red). The profiles show good geographic coverage of southern California and the coastal area north of the San Francisco Bay, and less coverage in the Central Valley and the northernmost part of the state. Itron sites with more than 1% of data missing from the three relevant months were discarded, amounting to around 10% of the sites.

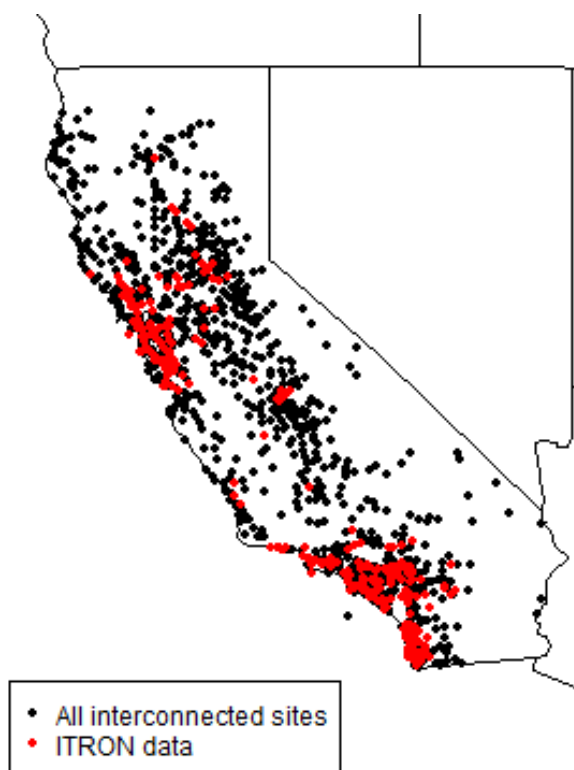


Figure 4. Locations of all sites in the NEM Currently Interconnected Database through the end of 2014 and those with 15-minute Itron profiles.

Historical hourly data for metered load and grid-scale solar energy output were obtained from the CAISO OASIS database. Metered load was disaggregated by IOU, and solar

⁹ Itron, Inc., 2011. "CPUC California Solar Initiative: 2010 Impact Evaluation." Prepared for Southern California Edison and California Public Utilities Commission, Energy Division.

production data were disaggregated by CAISO region (NP15, SP15, and ZP26). The generation and load of municipal utilities outside of CAISO's Balancing Area Authority was not accounted for in this analysis, and the CAISO solar data contained all types of solar (not only PV).

The grid-scale data were time-coincident with the BTM solar profiles. All results shown are in Pacific Standard Time (PST) or Pacific Daylight Time (PDT) as appropriate, and averages over the month of March are in PDT.

To analyze the effect of BTM solar on daily net-load patterns, the Itron profiles in each of the three major IOUs were scaled to the total BTM solar capacity in the IOU (as reported in the NEM Currently Interconnected dataset). The scaled profiles were added to CAISO metered load data for each IOU to remove the effect of BTM solar. Three load/net-load curves were examined: (1) load with the effects of BTM solar removed, (2) net load including the effects of BTM solar, and (3) net load including the effects of BTM solar and CAISO grid-scale solar power output. Data from SP15 and ZP26 in CAISO were grouped with southern California (with SDG&E and SCE), and data from NP15 was grouped with northern California (with PG&E).

The aggregate capacity of the BTM solar installations measured by Itron, as well as the total interconnected capacities, are shown in Table 2. In each of the IOUs, the aggregate capacity of the sites measured by Itron in 2014 amounts to about 0.1 % of the cumulative interconnected capacity that year.

Although the percentage of Itron coverage is low, it is sufficient to extrapolate to the total interconnected BTM sites with a good degree of confidence. Figure 5 shows average values and 95% confidence intervals for the annual capacity factor and coefficient of variation (standard deviation of power output divided by mean, COV) as a function of the number of Itron sites considered. When data from all of the 289 sites are used, there is a 95 % chance that the average capacity factor for the Itron sites, 0.165, is within 0.0038 of the average capacity factor of all installed BTM solar capacity. Likewise, there is a 95% chance that the average COV for the Itron sites, 1.48, is within 0.013 of the average COV for all installed BTM solar capacity.

Table 2. Total MW capacity measured by Itron, total interconnected capacity, and the percentage of interconnected capacity that was measured (2014 data).

	PG&E	SCE	SDG&E
Itron profiles (MW)	1.25	0.77	0.44
Total interconnected (MW)	1,268	822	311
Percent Itron covers	0.1 %	0.09 %	0.1 %

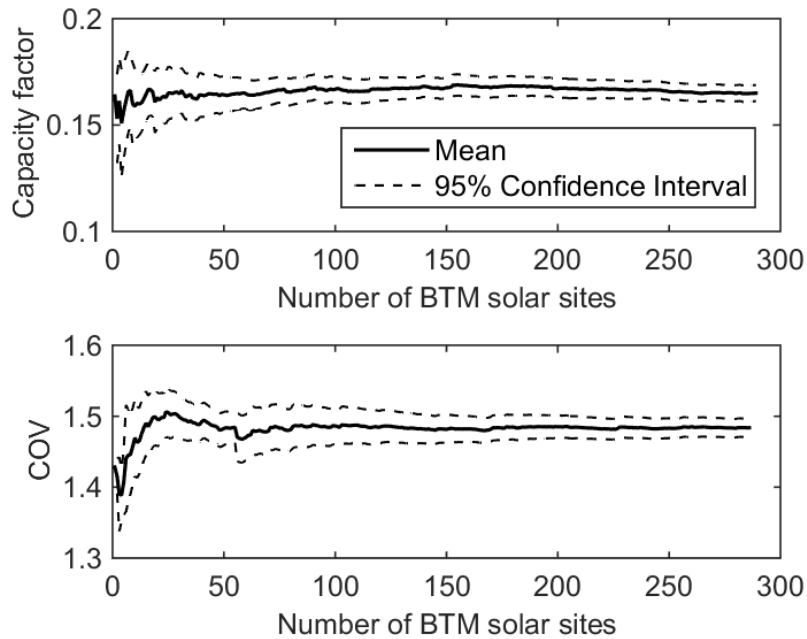


Figure 5. Mean and 95% confidence interval for capacity factor and coefficient of variation for BTM solar in California, based on the Itron data.

Figure 6 shows the relative frequency distribution (similar to a probability density function) of the nameplate capacities of the Itron sites and all interconnected sites. The distributions of nameplate capacities are very similar, implying that the Itron sites reasonably represent the nameplate capacities of the total set of interconnected sites.

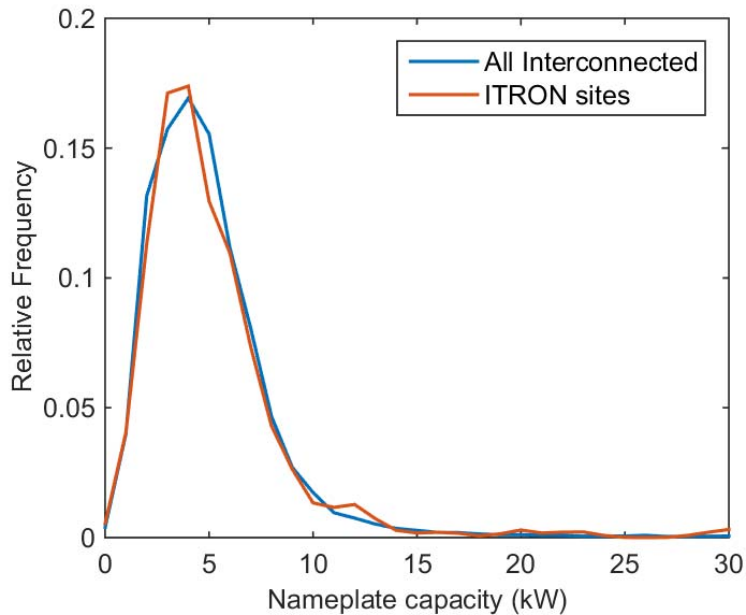


Figure 6. Distribution of nameplate capacities of BTM solar sites in California.

3.2 2014 load and net-load curves

This section presents the three load/net-load curves produced for 2014: load with the effects of BTM solar power removed, net load including the effects of BTM solar, and net load including the effects of both BTM and grid-scale solar.

Figure 7 shows average, maximum, and minimum net-load values, by hour, over March 2014 for northern and southern California. Both plots show that BTM and grid-scale (bulk) solar are beginning to increase the magnitude of the afternoon net-load ramp (the difference between maximum and minimum net load) between 15:00 and 18:00. Together, both types of solar add an average of over 1 GW to the afternoon ramp in the north and over 1.5 GW in the south. By the time of the peak load hour, approximately 19:00, solar plants have stopped producing.

In southern California, solar PV is beginning to reduce minimum net load in March. If minimum net load drops sufficiently low, base-load generators such as coal, gas, and nuclear plants may be unable to reduce their power production enough to match it (resulting in over-supply of power). Turning base-load power plants off entirely is often not an option, since they may be needed immediately once net load rises again and they cannot start up instantaneously. In addition, engineering challenges such as reduced system inertia and violation of reliability must-run (RMR) limits, will begin to impact grid stability if minimum net load dips low enough. Current solar capacity in California is not reducing minimum net load to the point where these issues are arising; however, they must be addressed in a future system with very high solar penetration.

Figure 8 shows that in July, current penetrations of grid-scale and BTM solar PV reduce daily maximum net load without introducing a steep afternoon ramp. The solid lines in Figure 8 show that on average, solar PV (both BTM and grid-scale) reduces daily maximum net load by 650 MW in northern California and nearly 2,000 MW in southern California. In northern California, the effects of BTM and grid-scale PV are approximately equal, while in southern California BTM solar reduces the average daily maximum by 300 MW with grid-scale solar accounting for the remaining 1,700 MW.

BTM and grid-scale solar PV is also reducing peak net load over the entire month (the upper dashed line in Figure 8). BTM solar reduced July peak net load by about 500 MW in northern California and 400 MW in southern California. Combined, all types of solar reduced peak net load by 900 MW in the north and 2,000 MW in the south. (In 2014, peak load in July was 20,000 MW in northern California and 25,900 MW in southern California).

If daily summer load shapes remain unchanged, additional solar PV capacity will have limited benefit in reducing summer peak net load further. At the current solar capacity, solar power has reduced daily peak net load almost to the extent that it occurs in hour 20, when solar plants have stopped producing. When peak net load occurs in hour 20, solar power will be unable to reduce it further (without a shift in load patterns or the use of storage).

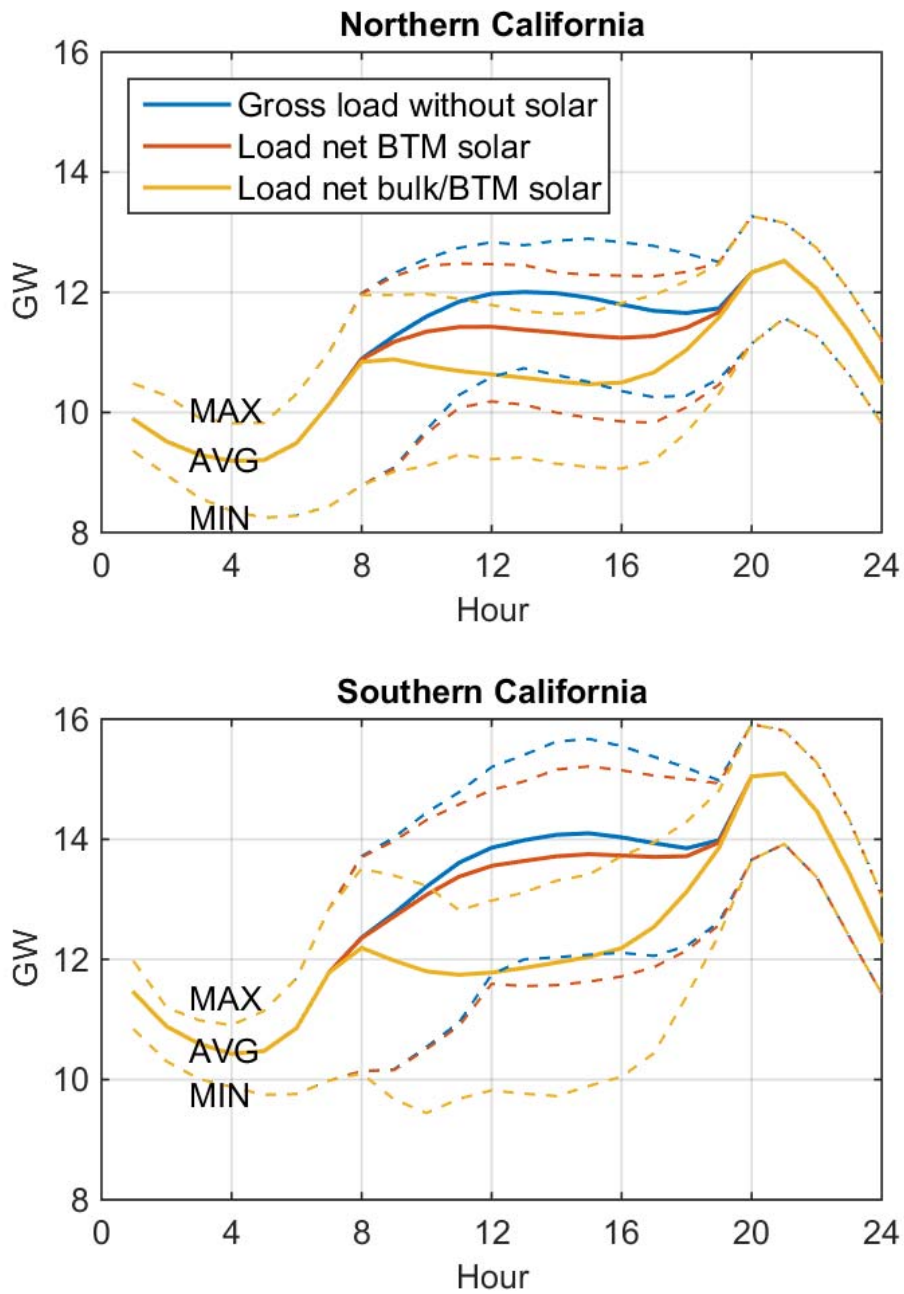


Figure 7. Load and net-load curves for March 2014, showing average (solid) and maximum/minimum (dashed line) values by hour for the month.

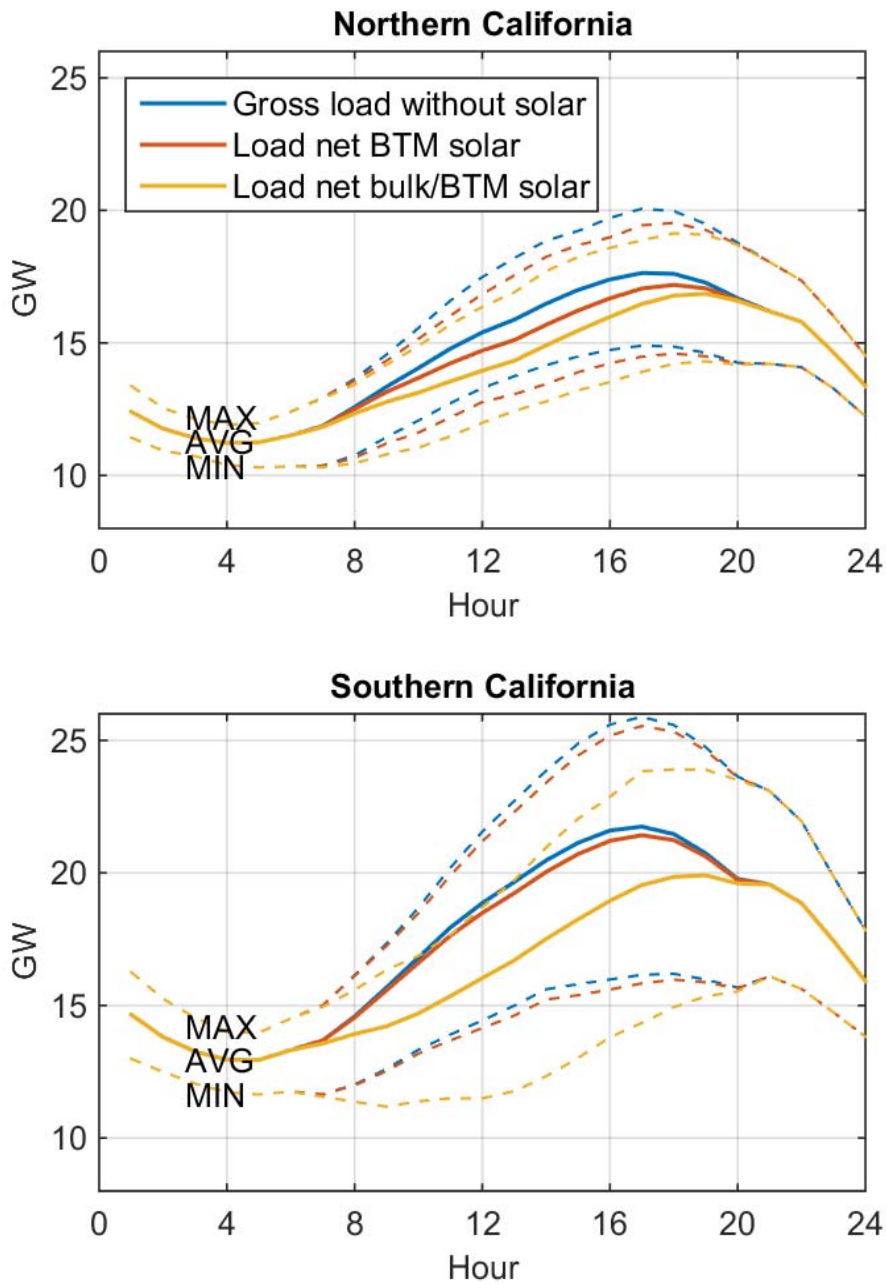


Figure 8. Load and net-load curves for July 2014, showing average (solid) and maximum/minimum (dashed line) values by hour for the month.

Figure 9 shows that in December, like in March, solar PV is extending the both duration and magnitude of the afternoon ramp, by approximately 600 MW in northern California and 2,000 MW in southern California. The steepest portion of the afternoon ramp and the daily load peak both occur after solar PV has stopped producing.

In southern California, solar PV is significantly impacting the December minimum net load (the lower dashed line in Figure 9), reducing it to 1.5 GW below minimum gross load. While the minimum of gross load occurred at approximately 04:00 in December 2014, solar power in southern California (both BTM and grid-scale) has shifted minimum net load to 13:00. Further analysis is required to determine the level at which low net load will begin to create challenges such as sub-optimal dispatch of base-load generators.

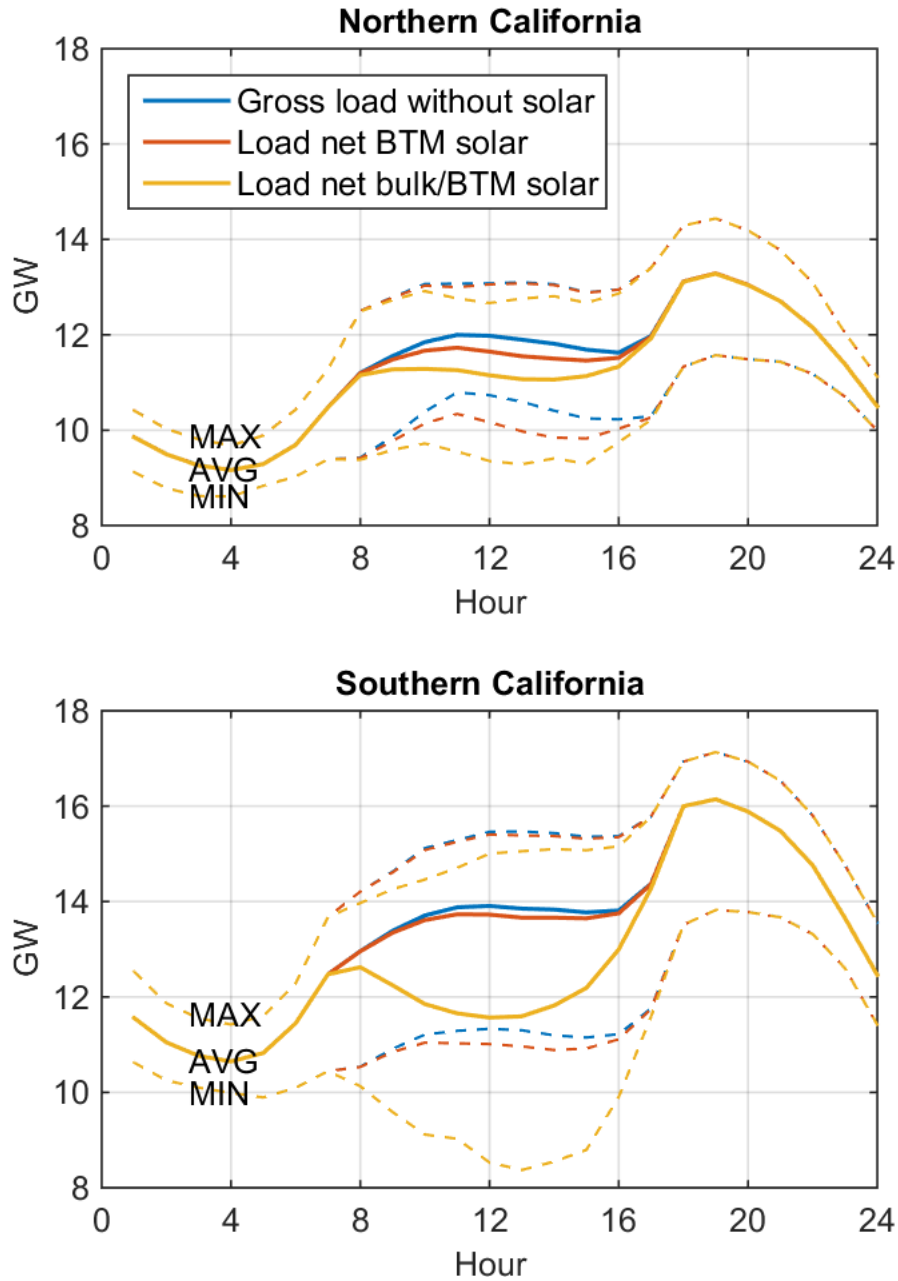


Figure 9. Daily load and net-load curves for December 2014, showing average (solid) and maximum/minimum (dashed line) values by hour for the month.

3.3 The effect of solar PV on 2014 maximum and minimum net load

Figure 10 shows the effect of BTM and bulk solar on average, minimum, and maximum 2014 net load in northern California by month. As reflected in Figure 7 through Figure 9, solar PV had no effect on monthly minimum net load in the north, which occurred in the early morning. In the south, solar PV reduced monthly minimum net load to an increasing extent throughout the year, likely reflecting increased grid-scale solar capacity coming online in CAISO. Solar PV had no effect on peak net load in the winter, when net-load curves are shaped similarly to Figure 9, but reduced monthly peak net load in the summer by about 1 GW in the north and up to 2.3 GW in the south. BTM solar provided 500 MW peak net-load reduction in the north and 400 MW in the south.

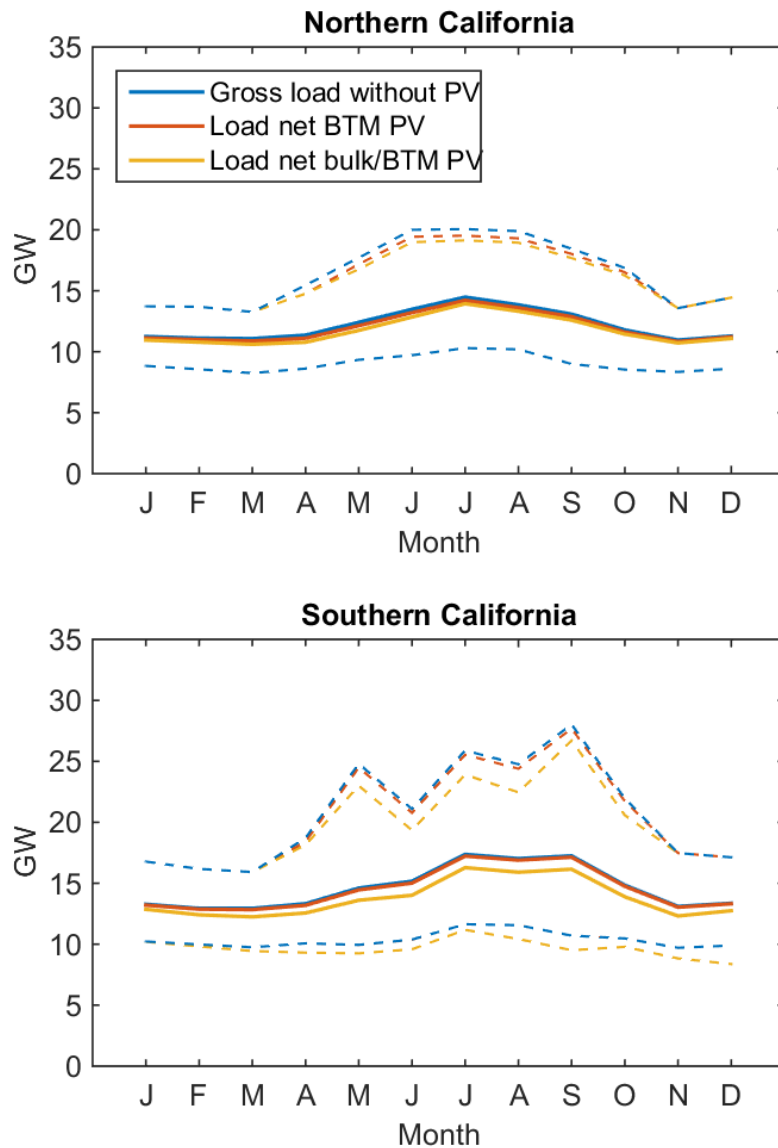


Figure 10. Mean (solid line) and maximum/minimum (dashed line) load/net load by month.



3.4 The effects of solar PV on the afternoon net-load ramp in 2014

This section presents more detailed analysis of the effect of BTM (and grid-scale) solar PV on the afternoon net-load ramp rate. The ramp rate is defined as the difference, in MW/h, between net load in a given hour and in the preceding hour. It indicates how quickly other resources in the system (primarily gas plants, though increasingly storage and demand response) need to ramp up to match supply with demand as solar production drops. In general, higher ramp rates correspond to greater system cost and more air pollution.

Figure 11 shows the average net-load ramp rate in the afternoon hours of March 2014 (with whiskers extending to the maximum and minimum values) in northern California. A positive value indicates the amount that generation capacity must ramp up in the given hour to match demand, while a negative value indicates how much it must turn down. Solar PV had the greatest effect on the afternoon net-load ramp rate for the hour ending at 18:00 for both northern California and southern California. In the north, BTM solar increased the average net-load ramp rate for this hour by about 180 MW/h and grid-scale solar by an additional 280 MW/h. Although the change in the afternoon net-load ramp rate is significant, the early morning net-load ramp remains the largest and is unaffected by solar PV (see Figure 7). In the south, BTM solar increased the net-load ramp rate in hour 19 by 100 MW/h and grid-scale solar by an additional 500 MW/h.

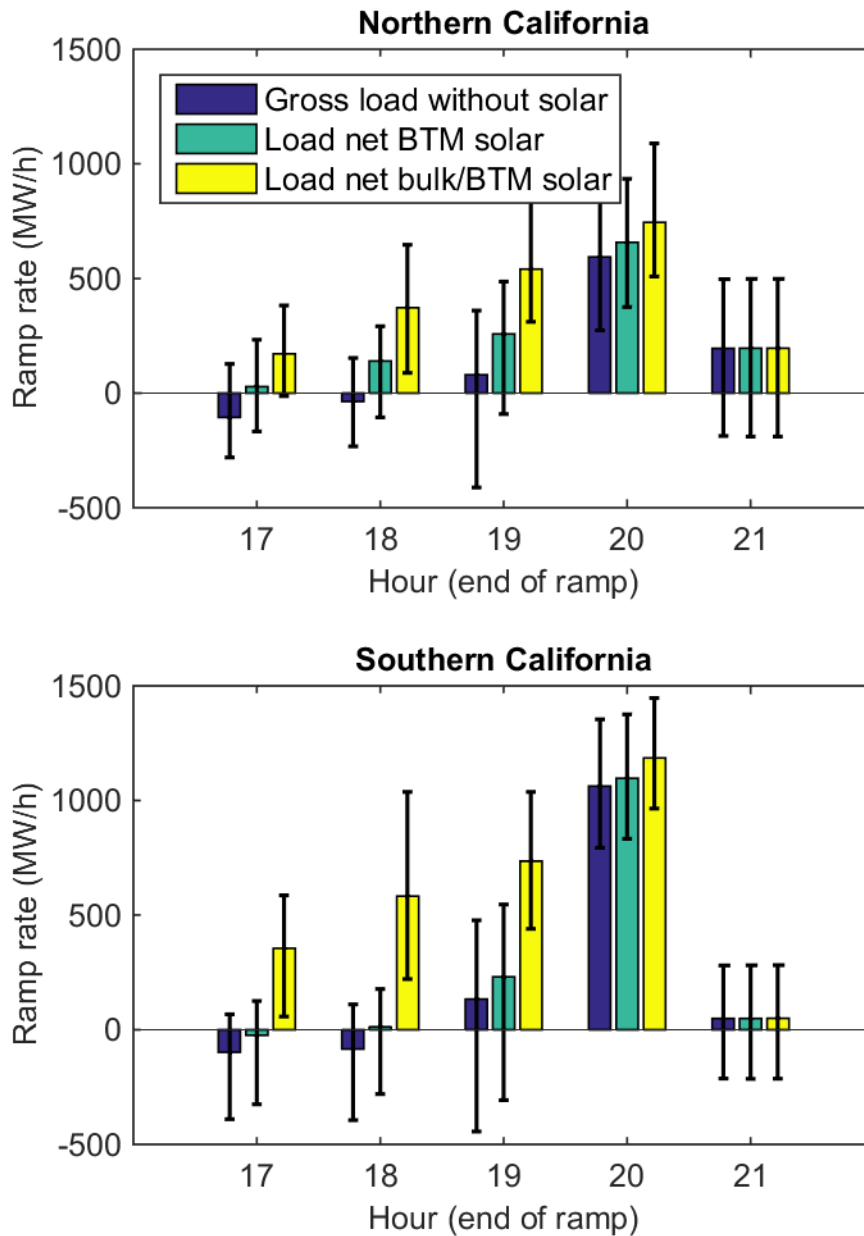


Figure 11. Magnitude of hourly ramp rate in load/net load for afternoon hours in March. Bars show average values and whiskers extend to maximum and minimum values.

For a more detailed view of the effect of PV on daily net-load patterns, Figure 12 shows cumulative distribution functions (CDFs) of the size of the net-load ramp rate in hour 19 of March 2014. Although these data represent the aggregate of over 289 BTM solar installations throughout California, it should be emphasized that the CDFs show a total of

only 31 data points (one for each hour of March 2014). The CDFs illustrate the overall effects of BTM solar on the afternoon ramp, but should not be interpreted as precise quantitative indicators, especially at the tails of the distribution.

In the absence of solar PV, the afternoon ramp rate in PG&E exceeded 500 MW/h for only 5% of hours in March 2014. Accounting for BTM PV, the afternoon ramp rate exceeded 500 MW/h for 10% of hours, and accounting for both BTM and grid scale PV, the ramp rate exceeded this level over 50% of the time. In southern California, there were similarly low odds that the ramp rate in only load or in load net BTM solar exceeded 500 MW/h in hour 19. When grid-scale PV is considered as well, the net-load ramp rate exceed this level on 80% of the days considered.

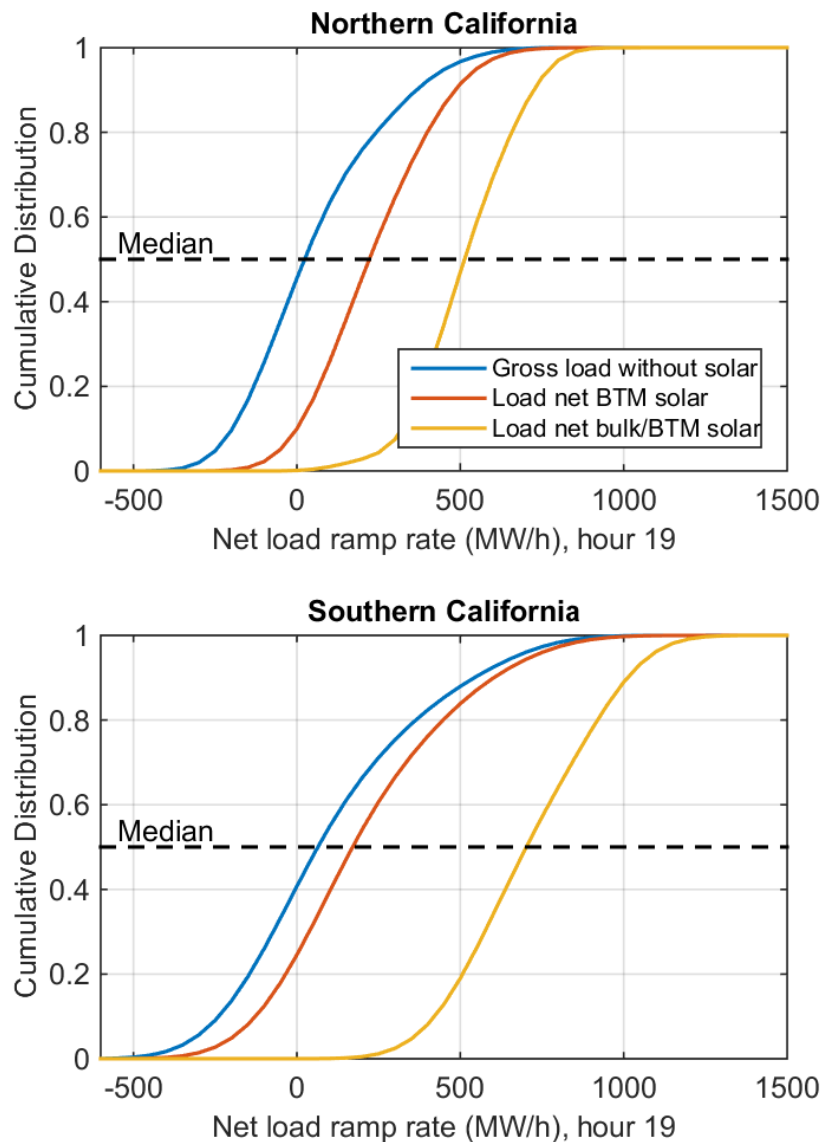


Figure 12. Cumulative distribution functions of the load/net-load ramp rate over hour 19 in March.

In July, solar PV at its current penetration significantly reduces maximum net load (see Figure 8). It is changing the shape of the afternoon ramp, both in northern and southern California, primarily by shifting the net-load ramp to later in the day and reducing the down-ramp in net load following the daily peak (Figure 13). As seen in Figure 8, solar PV at its current capacity has decreased the morning net-load ramp, especially in southern California.

In the afternoon, the largest effect of solar PV on the net-load ramp rate has been on hour 19; in this hour, solar PV changed the average net-load ramp from negative to positive, and at higher penetrations will continue to increase hourly ramping. In northern California, BTM and grid-scale PV each increased the net-load ramp rate in hour 19 by 200 MW/h. In southern California, grid-scale solar has the greater effect, raising the net-load ramp rate by almost 700 MW/h compared with 100 MW/h due to BTM solar.

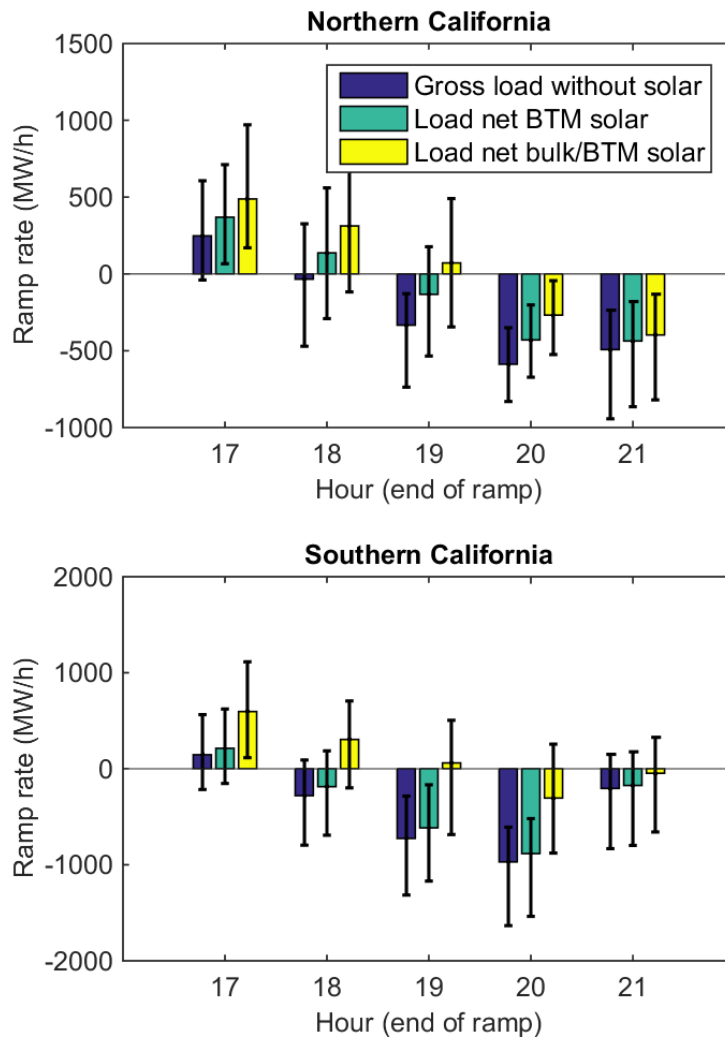


Figure 13. Magnitude of hourly ramp rate in load/net load for afternoon hours in July. Bars show average values and whiskers extend to maximum and minimum values.

Figure 14 shows CDFs of net-load ramp rates of hour 19 in July 2014. In northern California, solar PV has increased hourly ramp rates up without significantly affecting uncertainty. BTM solar PV has a similar effect in southern California. Grid-scale PV, however, has achieved high enough penetration to increase variability in hourly ramp rates as well. Considering only BTM solar, the net-load ramp rate in hour 19 fell in the range of -1050 MW/h to 150 MW/h (spanning 900 MW/h) for 90% of days in July 2014. When grid-scale solar is added, the net-load ramp rate fell between -450 MW/h and 550 MW/h (spanning 1000 MW/h) for 90% of days.

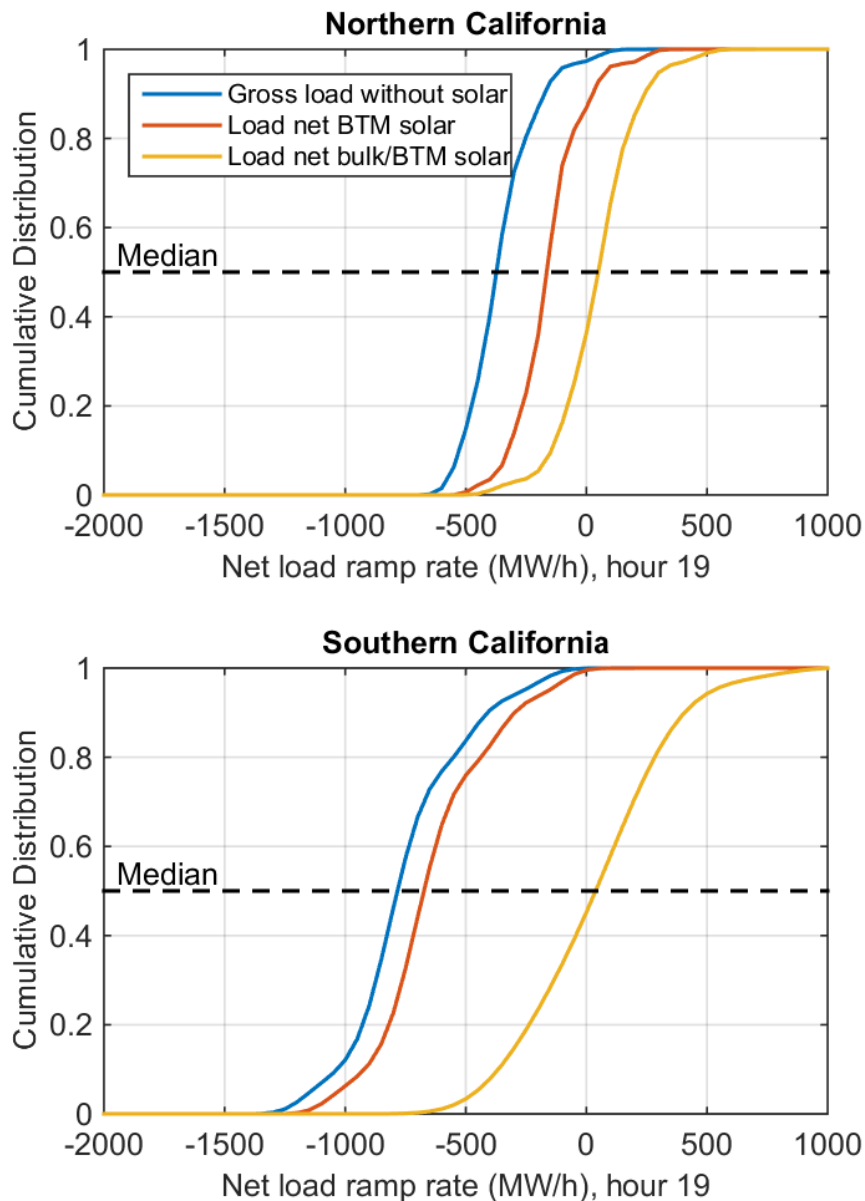


Figure 14. Cumulative distribution functions of the load/net-load ramp over hour 19 in July.

Increased variability (and uncertainty) in net load due to solar power output means that more quick-responding, dispatchable resources (primarily gas plants, in the current system) must be online to respond to changes in net load. Solar forecasting reduces, but does not eliminate, the uncertainty in ramp rates on operational time scales. Even with a perfect forecast, variability in ramping increases system cost by requiring a larger portfolio of resources to be available for commitment. This effect is small at current solar penetrations but will need to be mitigated further as solar capacity in California increases.

In December, unlike July, BTM and grid-scale solar are not reducing maximum net load (in the winter, maximum net load occurs after the sun has set). Winter load and solar patterns are such that BTM solar PV has slightly increased afternoon net-load ramp rates (Figure 15). Both BTM and grid-scale solar have had little effect in the hour of maximum net-load ramp rate, hour 18; the greatest effect of solar PV on afternoon ramp rate is in hour 17.

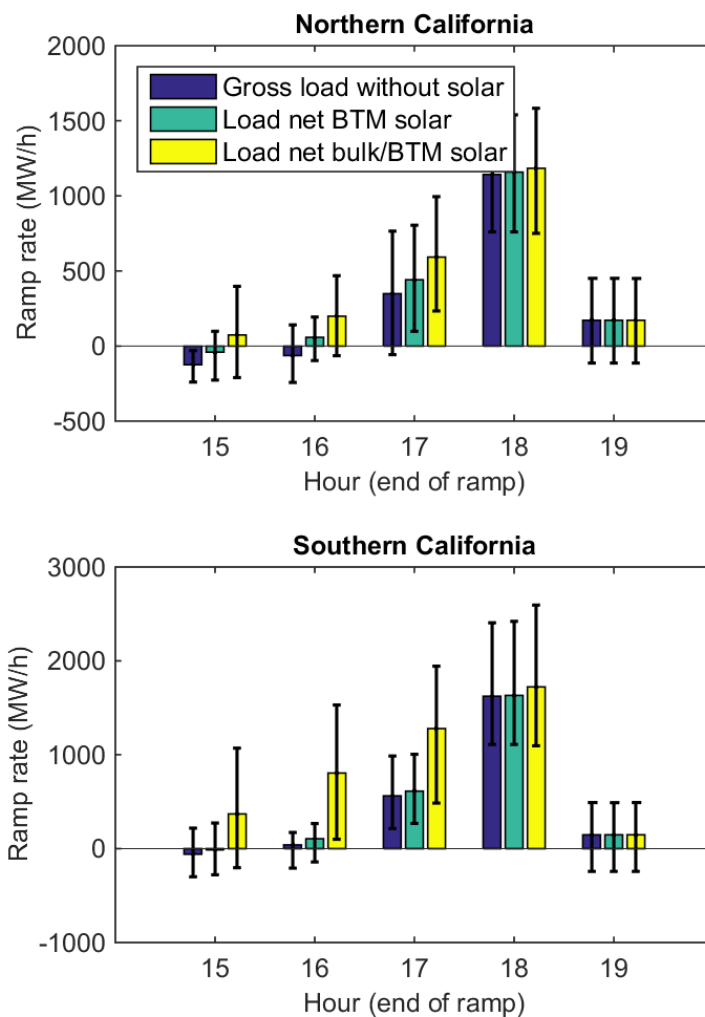


Figure 15. Magnitude of hourly ramp rates in load/net load for afternoon hours in December. Bars show average values and whiskers extend to maximum and minimum values.

Figure 16 shows cumulative distribution functions for net-load ramp rates in hour 17, demonstrating the effect of solar PV (primarily grid-scale, at current penetrations). In both northern and southern California, solar PV has shifted the majority of net-load ramps in this hour from below 500 MW/h to above 500 MW/h and has also increased their variability, with grid-scale PV accounting for the majority of this effect.

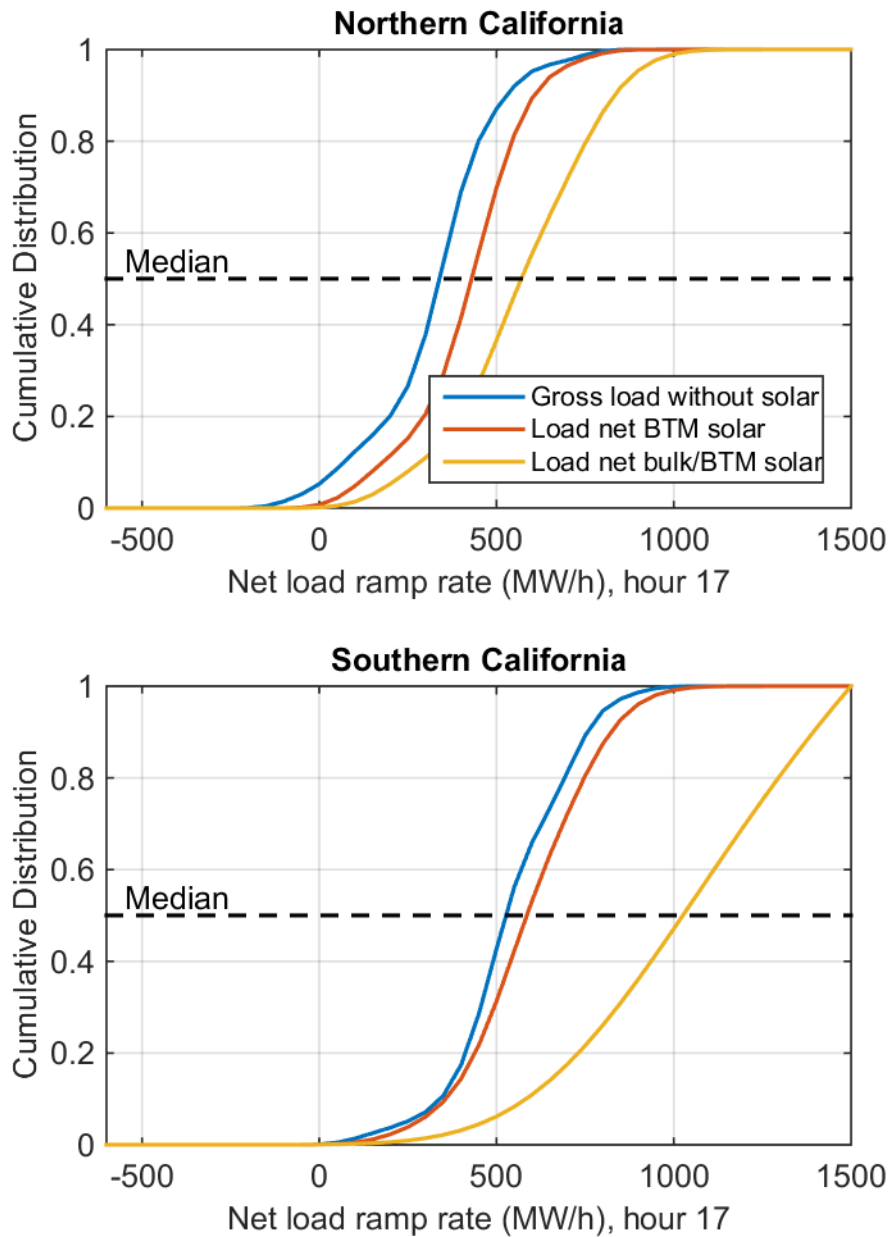


Figure 16. Cumulative distribution functions of the load/net-load ramp rate over hour 17 in December.

The California electricity grid is able to absorb the current effects of solar PV on winter net-load ramp rates. In the future, given much higher solar capacity, increased afternoon net-load ramp rates will require further mitigation. Currently, natural gas plants are the primary resources available to compensate for high afternoon net-load ramp rates. In the future, reliance on natural gas will become less feasible as California aims for tighter emissions targets and other grid integration strategies, such as time-of-use rates, dispatchable demand response, and storage will need to be deployed.

3.5 Differences in the effects of grid-scale solar and BTM solar by orientation

While the effects of grid-scale and BTM PV on daily net-load patterns are broadly similar, as penetrations of both types of solar increase, the differences between them will gain importance. While bulk PV tends to have a higher capacity factor, the concentration of capacity at a single location can result in greater volatility per MW installed. Daily generation patterns differ according to the azimuths of the systems as well, an effect that will gain prominence as penetration increases.

To best isolate the effect of azimuth, narrow definitions of south-facing (175 to 185 degrees) and west-facing (265 to 275 degrees) were adopted. (This contrasts with the data shown in Section 02, in which azimuths were classified in wider bins to indicate overall trends in installations.) Due to the small number of profiles for tracking solar (11 total), data from single-axis and dual-axis tracking sites are aggregated.

Table 3 and

Table 4 show capacity factor for different types of BTM solar PV in in 2013-2014. The capacity factor of tracking solar is higher than that of fixed-azimuth solar, especially in December. The empirical capacity factors are lower than the 24% reported for CAISO grid-scale solar¹⁰ and tend to be lower than the 20% estimated in a 2010 CPUC report for resources installed through the CSI program.¹¹

Table 3. Capacity factor for PG&E BTM solar data.

	March	July	December
BTM south-facing	0.12	0.17	0.06
BTM west-facing	0.09	0.18	0.06
BTM tracking	0.14	0.25	0.09

¹⁰ Schmalensee, R, 2013. The Performance of U.S. Wind and Solar Generating Plants. MIT Center for Energy and Environmental Policy Research.

¹¹ Energy and Environmental Economics, Inc., 2010. Inputs and assumptions to 33% Renewables Portfolio Standard Implementation Analysis.

Table 4. Capacity factor of SDG&E and SCE BTM solar data.

	March	July	December
BTM south-facing	0.14	0.16	0.09
BTM west-facing	0.19	0.21	0.09
BTM tracking	0.21	0.24	0.14

In many cases, the data on west-facing BTM solar indicates a higher capacity factor than south-facing solar, which contradicts theory. Possible explanations could include a tendency to install west-facing solar at sites with better resource bases or using higher-performing technology. Quantifying the total annual energy outputs of west-facing and south-facing solar would require accounting for these differences and was beyond the scope of this study. The results of this report are normalized by total energy produced (and not installed capacity) to provide a more consistent basis for comparison between south-facing and west-facing solar.

Section 3.4 showed that west-facing solar has the disadvantage of increasing the afternoon net-load ramp in winter and spring more than south-facing solar (given current daily load patterns), increasing the need for fast-ramping resources (primarily gas in the current system). This section shows that west-facing solar has the advantage of producing more power during afternoon hours of high summer demand, while south-facing solar offsets other types of generation earlier in the morning when demand is still relatively low. The marginal cost and emissions of thermal generation during higher-demand hours is likely more expensive and polluting than that during lower-demand hours, suggesting that west-facing solar may avoid system-wide cost and pollution more effectively than south-facing solar (though further analysis is required to confirm this). Taken together, these results indicate a tradeoff in the relative effects of west-facing and south-facing solar. Which orientation is most beneficial will depend on factors such as demand patterns and storage penetration, and may change as the energy system in California evolves.

Figure 17 shows average solar power output for grid-scale and BTM sites in northern California for March 2014, normalized by annual average power output. The peak of west-facing solar output is approximately one hour later than the peaks of grid-scale, south-facing, and tracking solar power output. (While installed capacity of the BTM sites was constant through the year, installed capacity of grid-scale solar appears to have increased. Although the general shape of the grid-scale solar output in Figure 17 through Figure 19 is valid, there is likely error in the values such that they should not be compared with those of BTM solar).

As shown in Figure 7, of the hours with significant solar power output, March net load is highest in hour 18. In this hour, west-facing solar is producing around 50% more power (relative to its maximum) than south-facing solar.

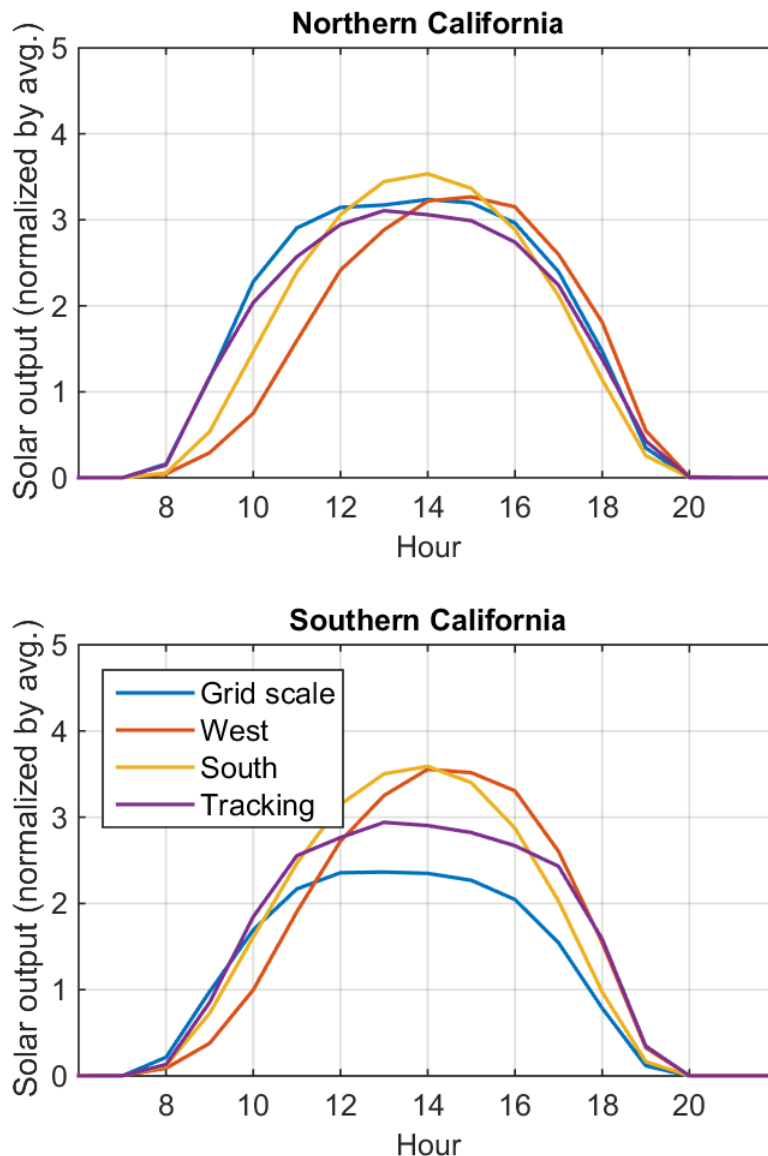


Figure 17. Hourly average generation of grid-scale and BTM solar in March 2014.

Figure 18 shows average power output for July, when peak load occurs in hours 17 and 18. In hour 17, west-facing solar produced 37% more energy than south-facing solar in northern California, and 43% more in southern California (relative to annual average power output). Given current load patterns and installed capacities, west-facing solar is better able to reduce peak net load and therefore avoid energy produced by peaker plants (often costly, high-emitting combustion turbines) more effectively than south-facing solar.

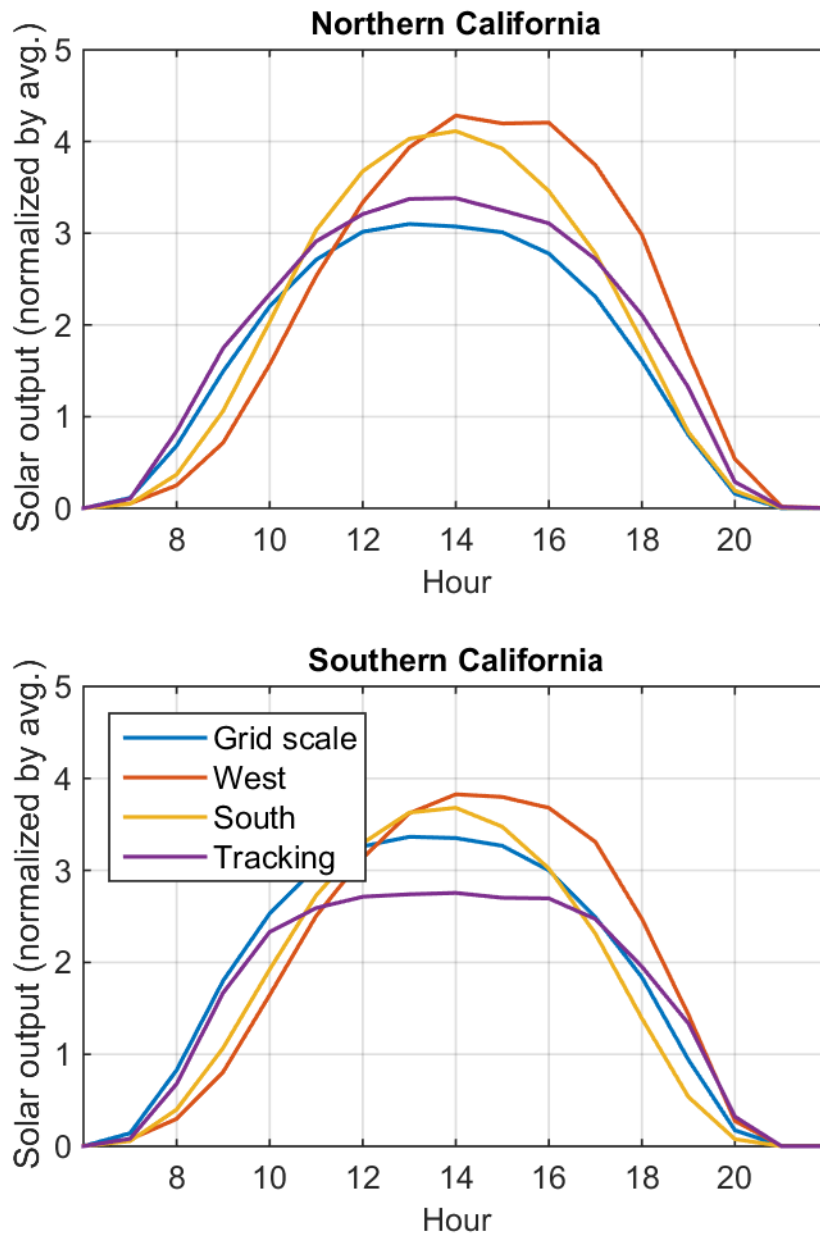


Figure 18. Hourly average generation of grid-scale and BTM solar in July 2014.

In December, average daily peak load occurs after solar plants have stopped producing. Figure 19 shows that west-facing solar produces relatively more energy during hour 16, however, when net load is higher than in other hours of solar production, demonstrating a way in which west-facing solar may reduce system cost and emissions more effectively than south-facing solar.

West-facing solar consistently peaks one hour later over all months and regions. Tracking solar and grid-scale solar show more consistent power output through mid-day, while south-facing solar has a shorter-duration peak. For fixed azimuth solar, a portfolio of different orientations will help provide more consistent power output throughout the day.

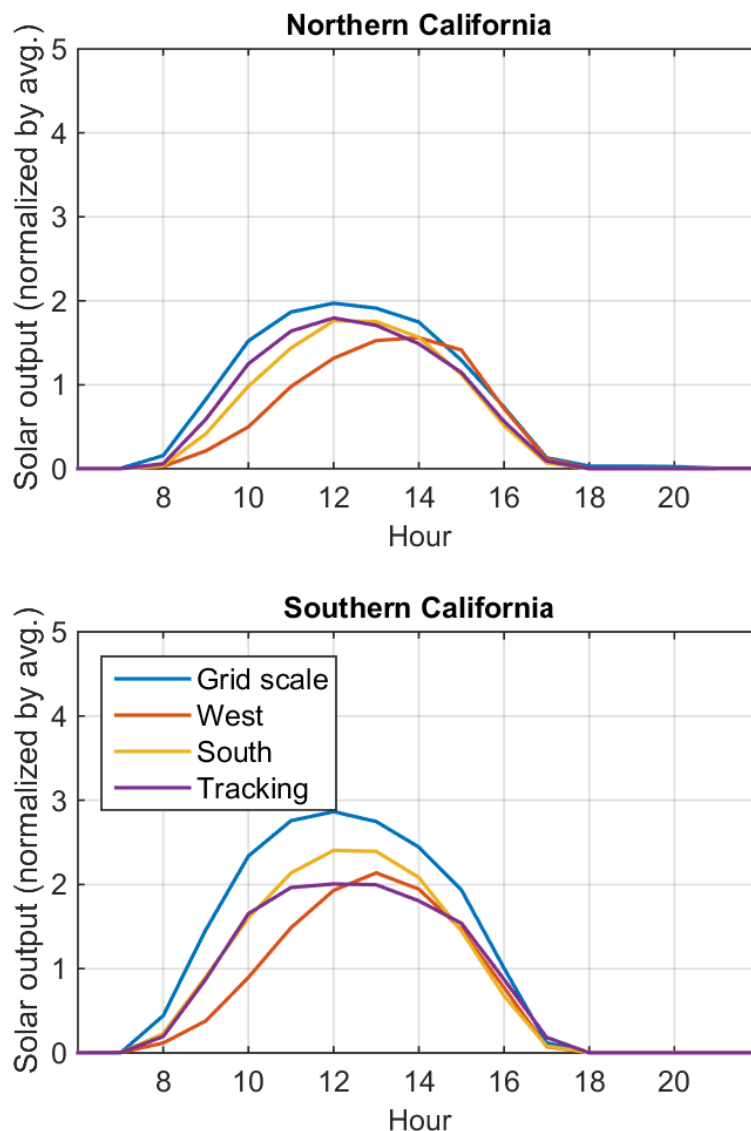


Figure 19. Hourly average generation of grid-scale and BTM solar in December 2014.

The daily patterns of power output for different types of PV systems have different effects on net-load ramp rate. Figure 20 shows the magnitude of the average downward ramp rate in power output for CAISO grid-scale PV, BTM south-facing, and BTM west-facing PV in March 2014. The hourly ramps are expressed as fractions of average power output and represent the upward change in net-load ramp rate that accompanies an additional MWh of solar PV energy.

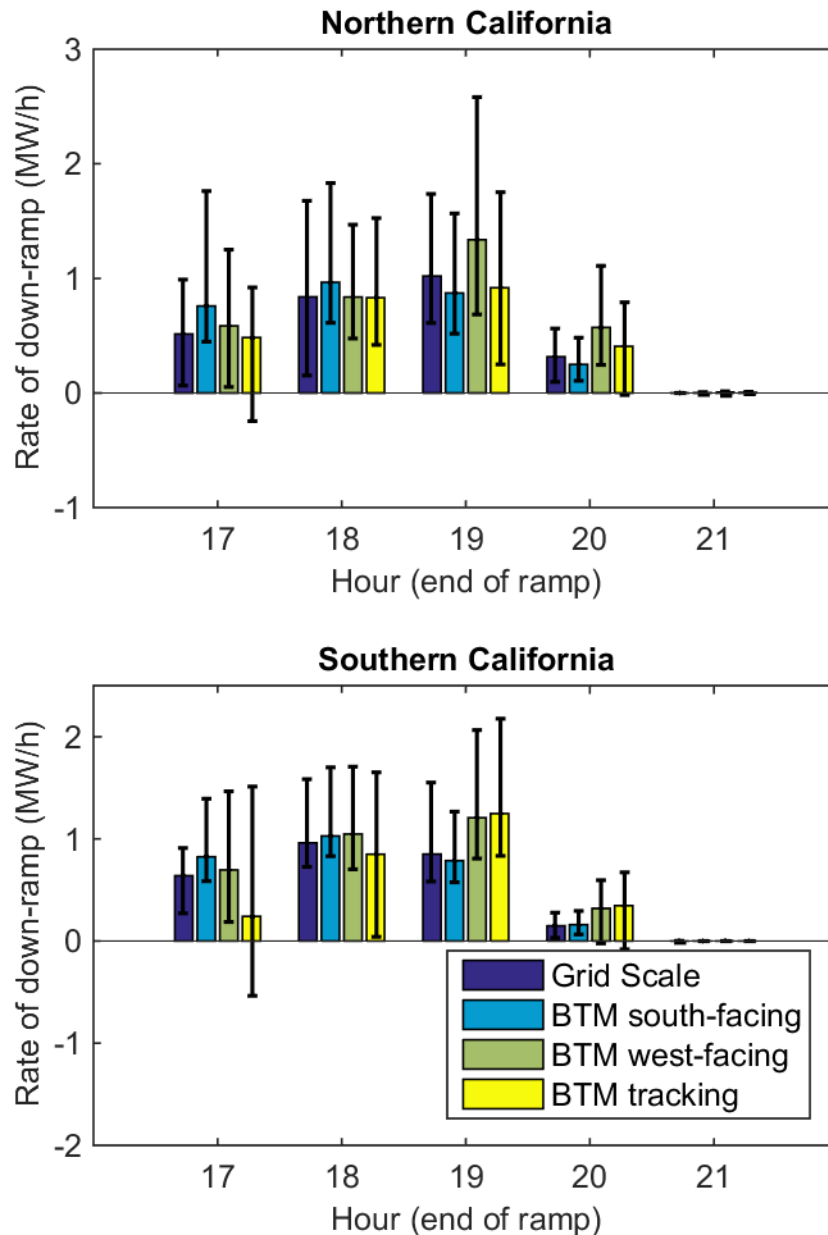


Figure 20. Average hourly change in grid-scale PV output from CAISO (SP15) and BTM solar in March 2014, with maximum and minimum values indicated by error bars.




Figure 20 shows that in March, west-facing solar PV increases the afternoon net-load ramp rate the most during hours 19 and 20 in both northern and southern California. In hour 19, the ramp rate of west-facing solar on average is 49 % greater than south-facing solar in northern California, and 53 % greater in southern California. These are the hours already experiencing the largest ramp rates (see Figure 11), implying that west-facing solar PV steepens the afternoon net-load ramp in March more than south-facing solar does. While the overall effect is currently small, large amounts of west-facing solar could increase the need for fast-ramping resources (primarily gas, in the current system) more than south-facing solar.

Ramping patterns of tracking solar are similar to grid-scale solar in northern California, and in southern California, tracking solar contributes to the most severe hours of the afternoon ramp at the same levels as west-facing solar. Tracking solar has a flatter production profile at its peak, like grid-scale solar, followed by a late afternoon down-ramp similar to that of west-facing solar.

Figure 21 shows the cumulative distribution functions (CDF) of relative increase in net-load ramp rates in hour 19 due to different types of solar in March 2014. In northern California, grid-scale solar and BTM tracking and south-facing solar almost never contribute more than double their average power output to the ramp rate in this hour. West-facing-BTM solar, however, added more than double its average power output to the ramp rate on almost 20% days in March 2014. In southern California, west-facing solar also contributes consistently more to the afternoon ramp than other types of solar except tracking. These results represent data for only 31 days and should not be interpreted as quantitatively precise. However, the consistency of qualitative results between northern and southern California, and among months, gives confidence to the overall conclusions.

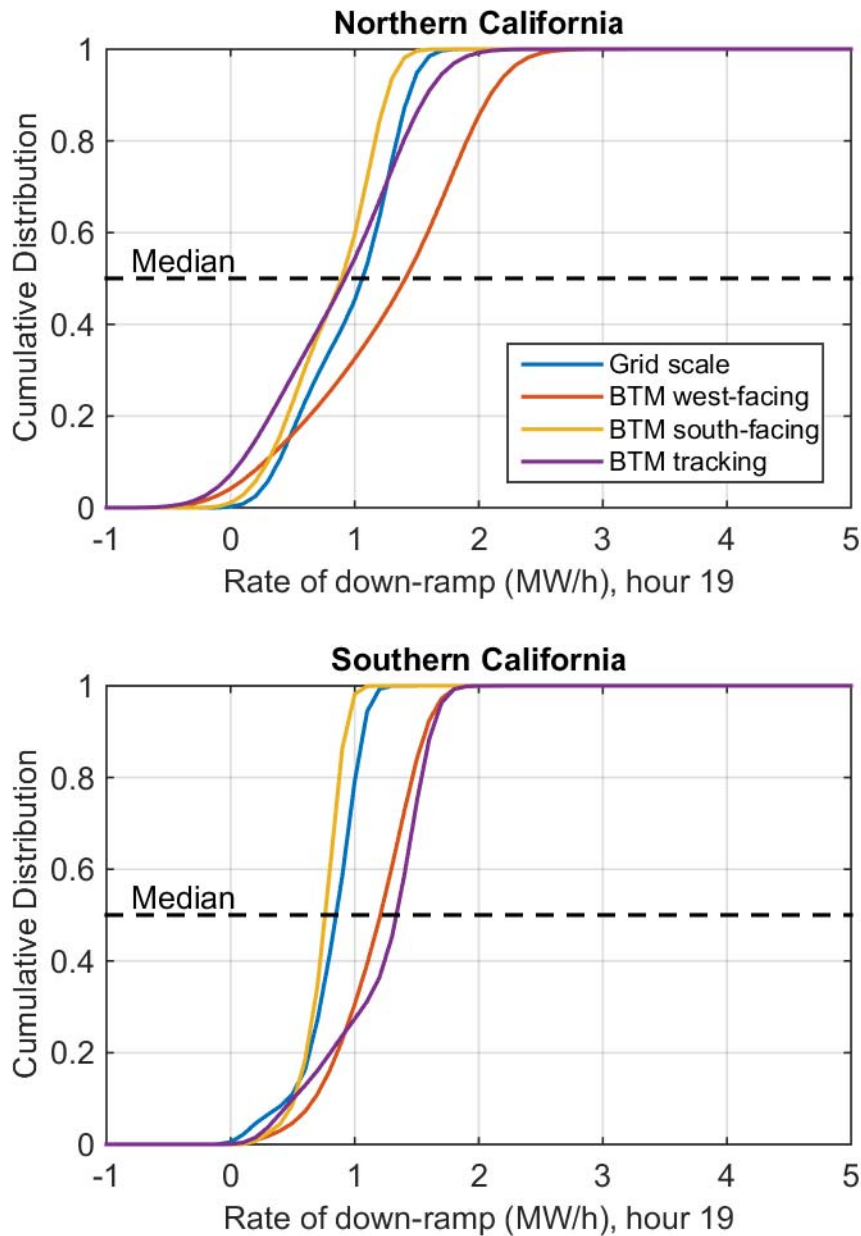


Figure 21. CDF of solar PV ramp rate (normalized by average power output) in hour 19 of March 2014.

For a visual depiction of the effects of BTM solar azimuth on daily net-load patterns, Figure 22 shows average net-load curves for a counterfactual case in March 2014 where solar capacity was doubled and replaced entirely with either south-facing BTM solar or an equivalent amount (by energy) of west-facing BTM solar. While the figure does not

represent a projection of an actual future net-load curve, it provides an intuitive illustration of the overall daily net-load shapes promoted by west-facing and south-facing solar. The figure shows the steeper afternoon ramp (and higher mid-morning net load) caused by west-facing solar.

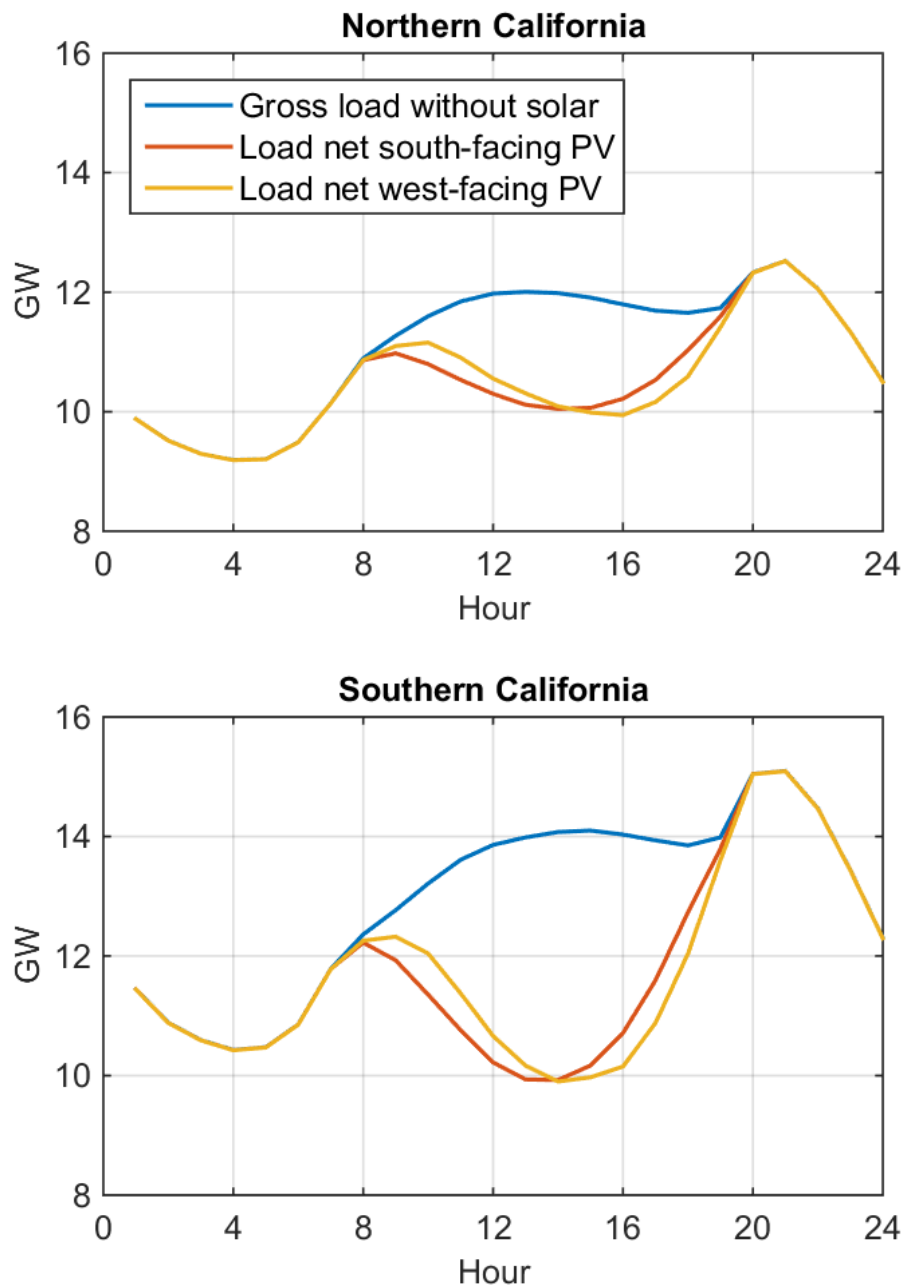


Figure 22. Hypothetical net-load curves for March 2014 if solar capacity were doubled and replaced with west-facing or south-facing BTM solar (to illustrate overall effects on net load).

Figure 23 shows the relative contributions of different types of solar PV to the afternoon ramp in July. In July, peak net load occurs in hour 17, suggesting that south-facing solar steepens the ramp up to peak net load to a greater extent than west-facing solar. In hours 19 and 20, west-facing solar ramps down more quickly than south-facing, better matching the decrease in load. This result, combined with the ability of west-facing solar to more efficiently reduce summer peak load, favors west-facing solar over south-facing solar in the summer.

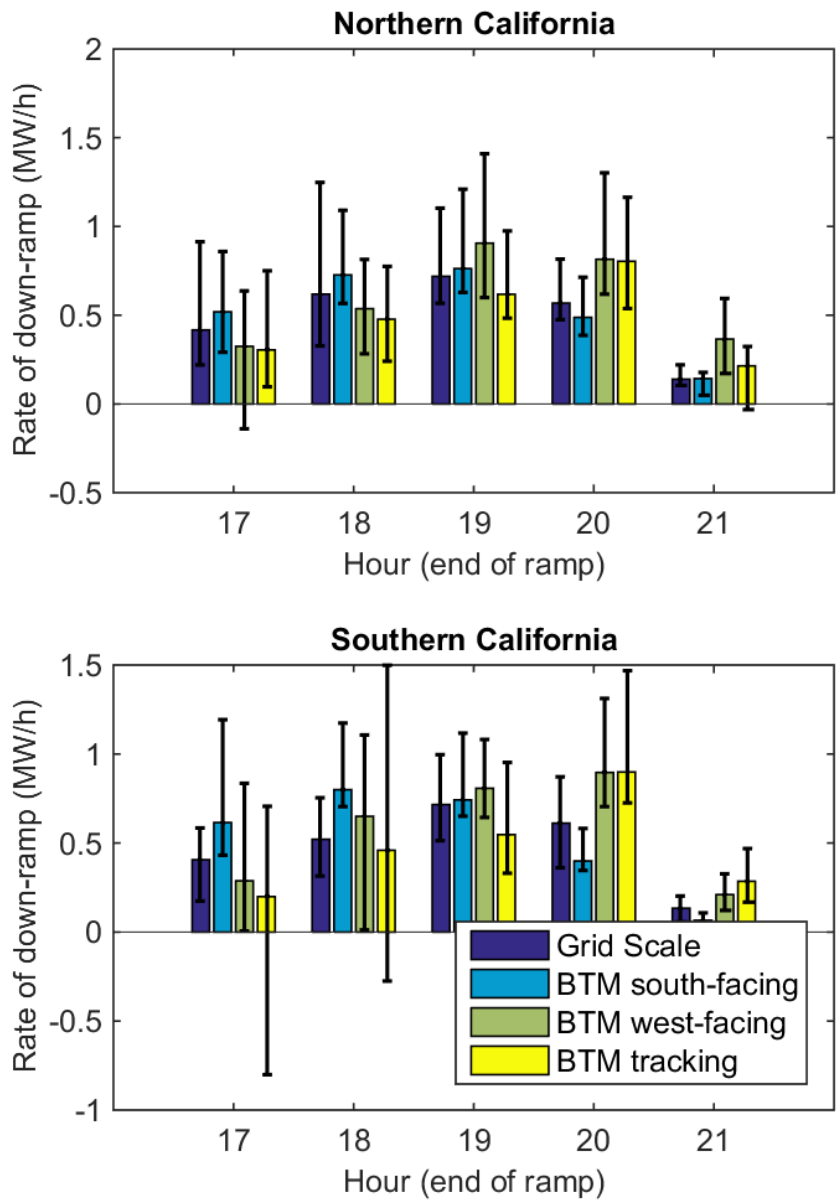


Figure 23. Average hourly change in PV output from CAISO (SP15) and BTM solar in July 2014, with maximum and minimum values indicated by error bars.

Figure 24 shows CDFs of the contribution of different types of solar to the net-load ramp rate in hour 20 in July, the hour of greatest solar down-ramp. Compared with March, all types of solar ramp slowly relative to their energy output.

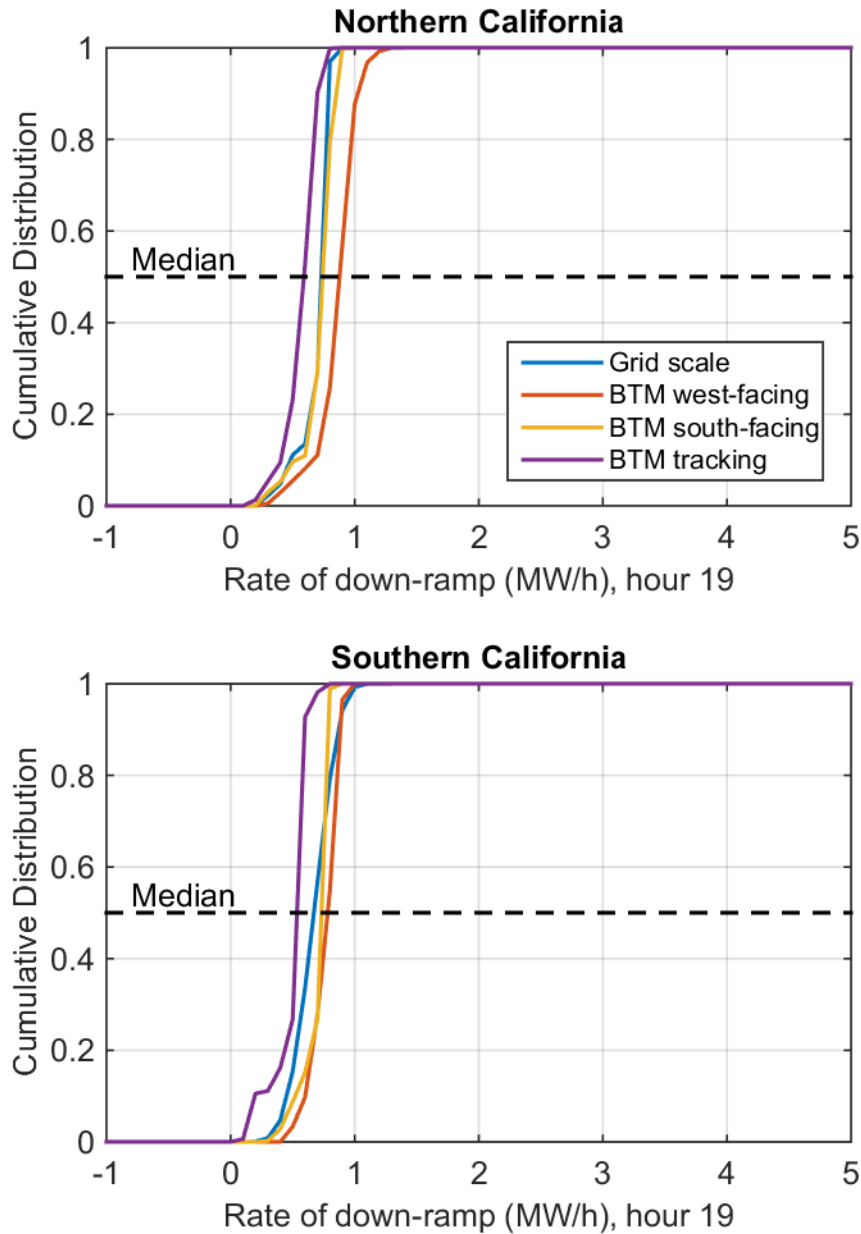


Figure 24. CDF of solar PV ramp rate (normalized by average power output) in hour 19 of July 2014.

For a visual depiction of the effects of west-facing vs. south-facing BTM solar on July net load, Figure 25 shows net-load curves for a hypothetical case in which solar capacity were doubled and replaced entirely with either west-facing or south-facing BTM solar. At this capacity, both types of solar have the beneficial effect of significantly reducing peak net load without substantially increasing net-load ramp rate. Peak net load occurs at approximately 17:00, which is closer to the peak output of west-facing solar than south-facing solar. The closer alignment of west-facing solar with load allows it to more effectively reduce peak net load while contributing minimally to net-load ramp rates.

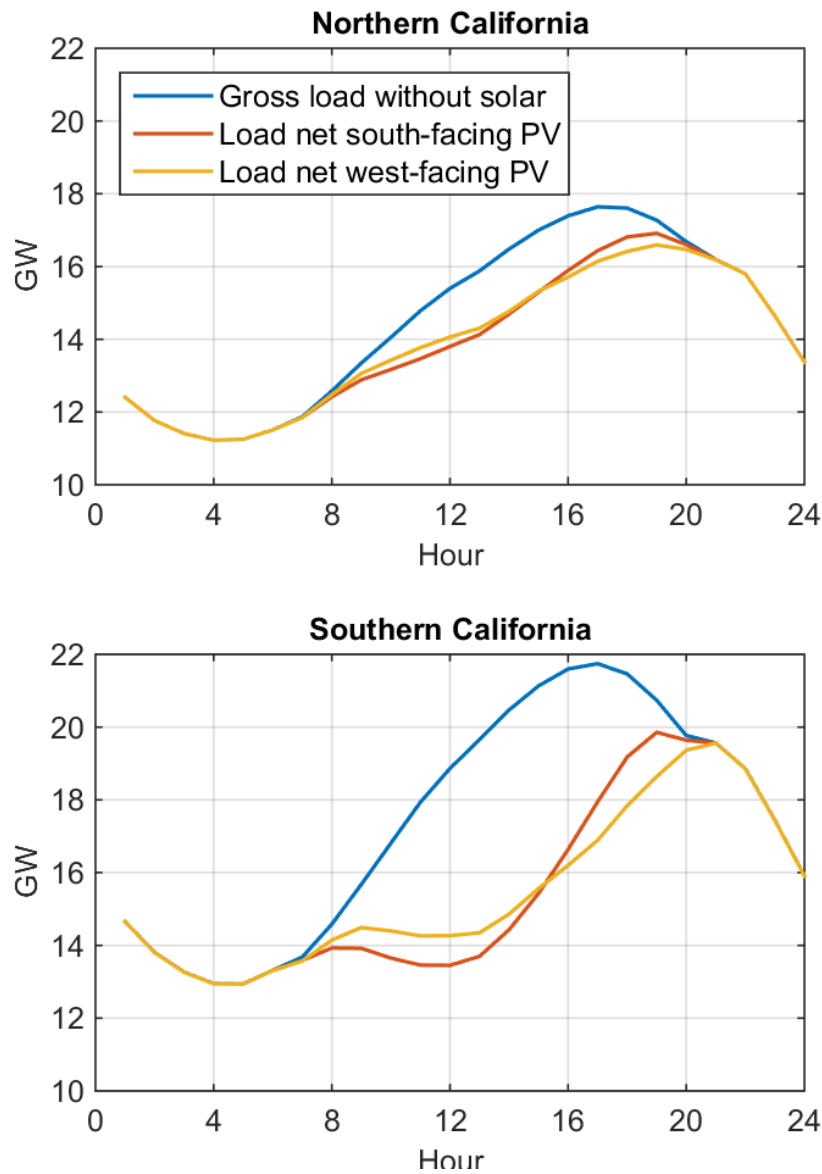


Figure 25. Hypothetical net-load curves for July 2014 if solar capacity were doubled and replaced with west-facing or south-facing BTM solar (to illustrate overall effects on net load).

In December, the load ramp rate is greatest in hour 19, when solar power output has almost fallen to zero. The ramp rate is also high in hours 16 and 17 (see Figure 15). Figure 26 shows that west-facing solar contributes the most to the afternoon ramp rate during these hours, relative to its average power output. In northern California, the average ramp rate of west-facing solar is 55 % higher than that of south-facing solar; in southern California, it is 50 % higher. This means that each MWh obtained from west-facing solar requires 50 % more ramping activity from other system resources, primarily natural gas in the current system, than south-facing solar. This effect is very dependent on current load patterns and will change as energy storage, dispatchable demand response, and time-of-use pricing start to reshape daily load patterns.

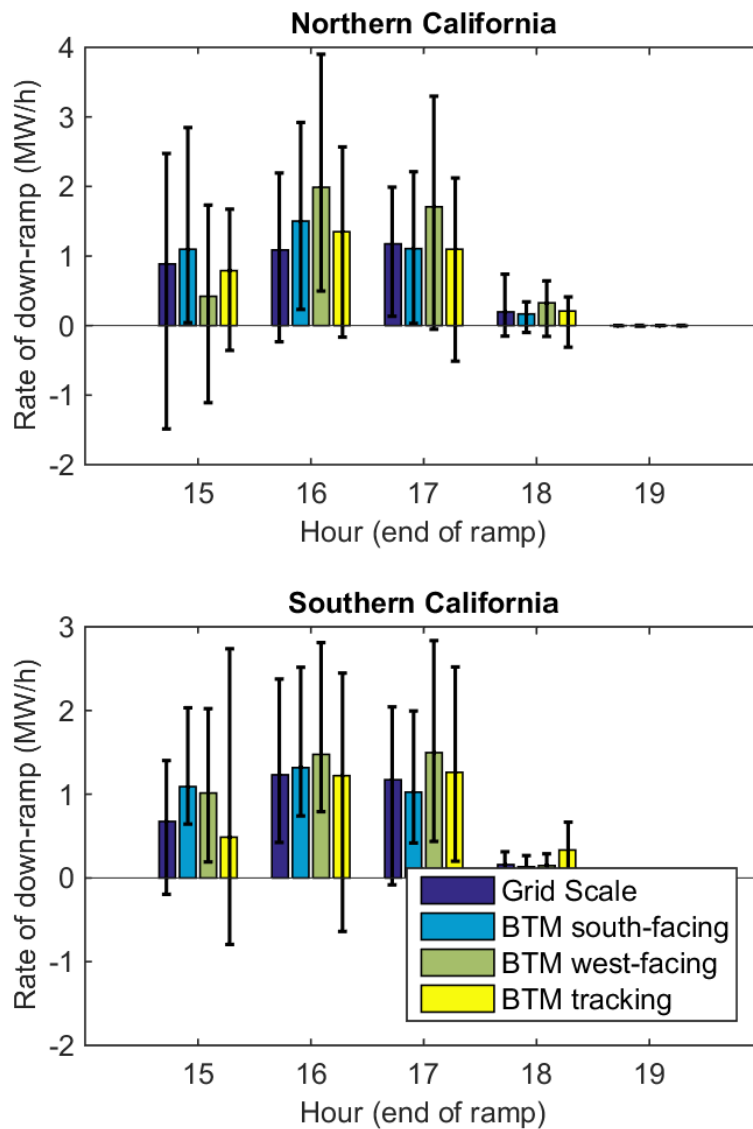


Figure 26. Average hourly change in PV output from CAISO (SP15) and BTM solar in December 2014, with maximum and minimum values indicated by error bars.

Figure 26 shows that in December the hour of highest net-load ramp rate to which solar contributes is hour 17. A CDF of the ramp rates, relative to energy output, is shown in Figure 27. Down-ramps in grid-scale PV tend to be smaller and less variable, an effect that may be explained largely by the higher December capacity factor of grid-scale solar (decreasing the ratio of ramp rate to energy output). In northern California, west-facing solar has the largest and most variable contribution to net-load ramp rate, with the middle 90% of data (between the 5th and 95th percentile) falling in the interval of -0.2 to 3.8 MW/h ramping per MWh produced, as compared with a range of 0 to 2.2 for south-facing solar. In southern California, west-facing solar tends to increase net-load ramp rates more than other types of solar, though by a smaller margin than in the north.

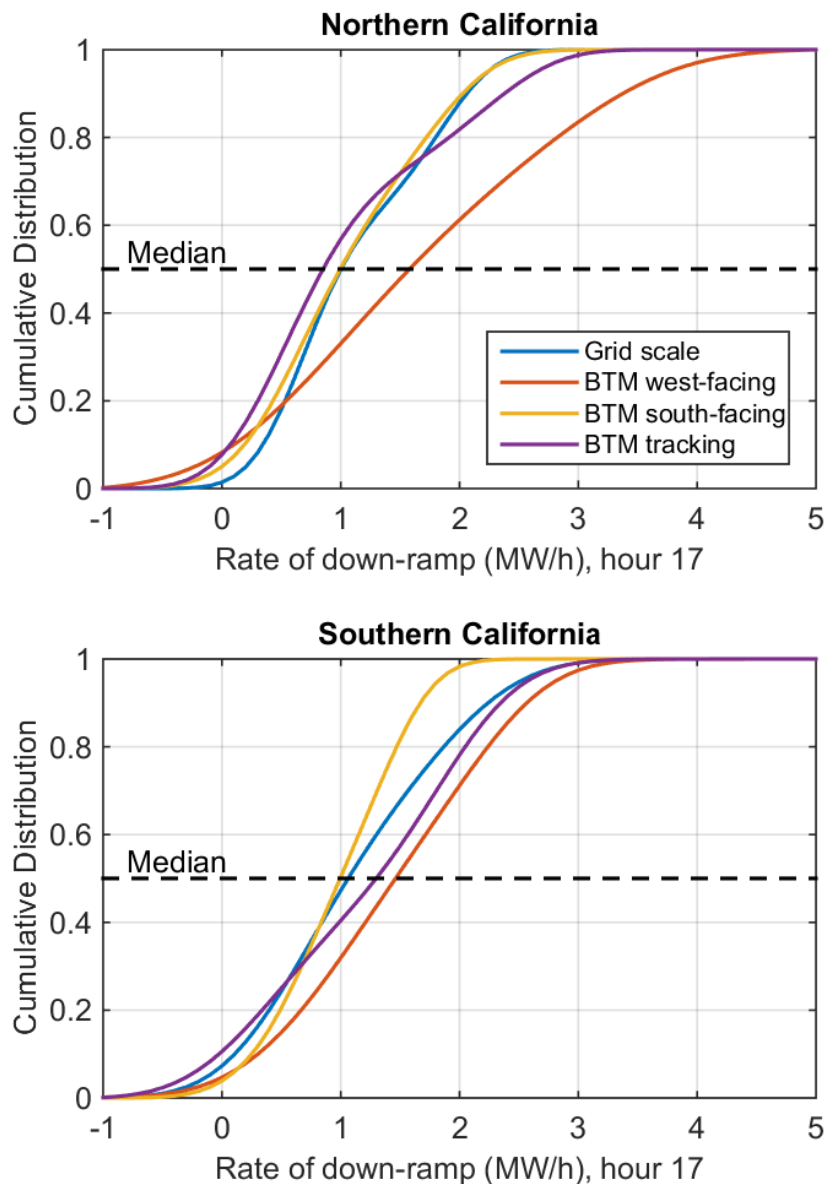


Figure 27. CDF of solar PV ramp rate (normalized by average power output) in hour 17 December 2014.

For an intuitive illustration of the effects of south-facing and west-facing BTM solar on daily load patterns, Figure 28 shows net-load curves for a counterfactual scenario for December 2014 in which solar capacity were doubled and replaced with either south-facing or west-facing BTM solar. South-facing solar is better aligned with the noontime peak, causing a less volatile net-load curve in the middle of the day. West-facing solar contributes more to both the steepness and overall magnitude of the afternoon net-load ramp. In addition, in systems with large amounts of solar capacity, west-facing solar may contribute to over-supply of power more than south-facing solar, as shown by the lower minimum net load for west-facing solar in southern California in Figure 28.

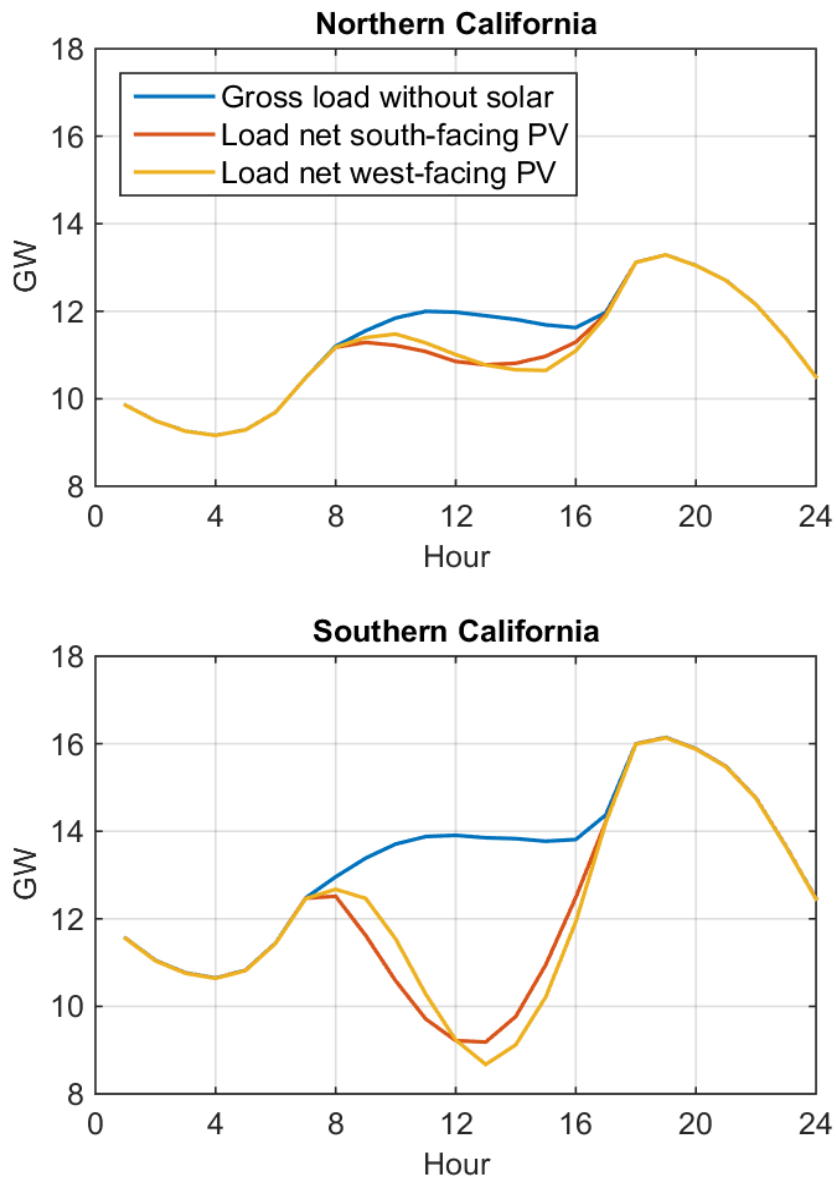


Figure 28. Hypothetical net-load curves for December 2014 if solar capacity were doubled and replaced with west-facing or south-facing BTM solar (to illustrate overall effects on net load).

3.6 Correlation analysis of BTM solar, grid-scale solar, and wind power output

The correlation of the power output of different renewable resources has strong implications for renewables integration. The addition of renewables always adds overall variability (barring cases of unrealistically high negative correlation). However, lower correlation between VER resources results in less volatility that other system resources have to balance.

Table 5 shows correlation coefficients between BTM solar, grid-scale solar, and grid-scale wind in northern California. Different types of BTM sites are highly correlated with each other, implying that diverse azimuths provides relatively little additional smoothing of hour-to-hour variability. The correlation between the BTM sites and bulk solar power output is much lower, showing a small but advantageous portfolio effect of combining grid-scale and BTM resources. (This effect may be due to more smooth, consistent output from BTM sites aggregated across a large geographical area vs. more volatile output from CAISO solar, which is concentrated in fewer sites. Capacity additions in CAISO throughout 2014, creating an overall upward trend in energy production, may also have lowered correlation with BTM solar.)

All of the solar resources are negatively correlated with grid-scale wind power output, showing a strong portfolio effect of combining wind and solar resources to mitigate the overall hour-to-hour variability of renewables. Table 6 shows the same patterns hold true in southern California.

Table 5. Correlation coefficients between PG&E BTM data and bulk CAISO renewables in NP15.

	BTM south	BTM west	BTM tracking	CAISO solar	CAISO wind
BTM south	1	0.95	0.93	0.76	-0.10
BTM west		1	0.90	0.67	-0.06
BTM tracking			1	0.73	-0.06
CAISO solar				1	-0.13
CAISO wind					1

Table 6. Correlation coefficients between SCE/SDG&E BTM data and bulk CAISO renewables in SP15.

	BTM south	BTM west	BTM tracking	CAISO solar	CAISO wind
BTM south	1	0.96	0.94	0.58	-0.09
BTM west		1	0.92	0.61	-0.02
BTM tracking			1	0.65	-0.10
CAISO solar				1	-0.05
CAISO wind					1

3.7 Geographic effects of BTM solar

Due to the size and climate diversity of California, solar plants located in different parts of the state may show contrasting patterns in energy production. To examine this effect, solar profiles from the Itron database were aggregated by Building Climate Zone (shown in Figure 29). Only sites that face due south (between 175 and 185 degrees) were examined to control for the effect of azimuth on results, and zones with under 30 kW installed capacity were excluded.

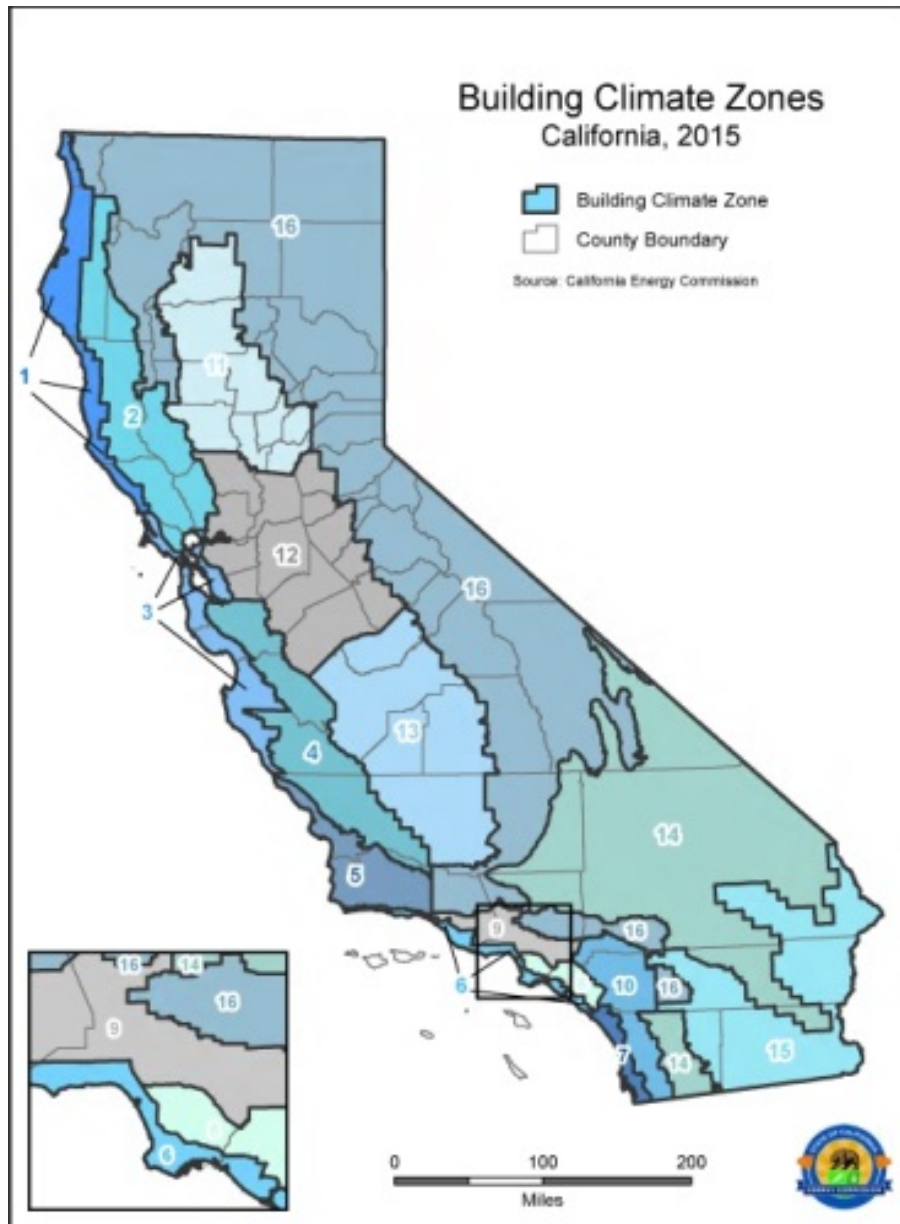


Figure 29. Building climate zones (image from California Energy Commission, http://www.energy.ca.gov/maps/renewable/building_climate_zones.html).

A primary difference among the solar production profiles in the different climate zones is the times at which they peak. Figure 30 shows approximate peak solar times by zone for March, July, and December of 2014. BTM solar in the easternmost zones, along the southern coast, tends to peak 20-30 minutes before that in the westernmost zones. Note that Figure 30 is based on maximum power production for historical average data and will not correspond exactly to maximum solar irradiance.

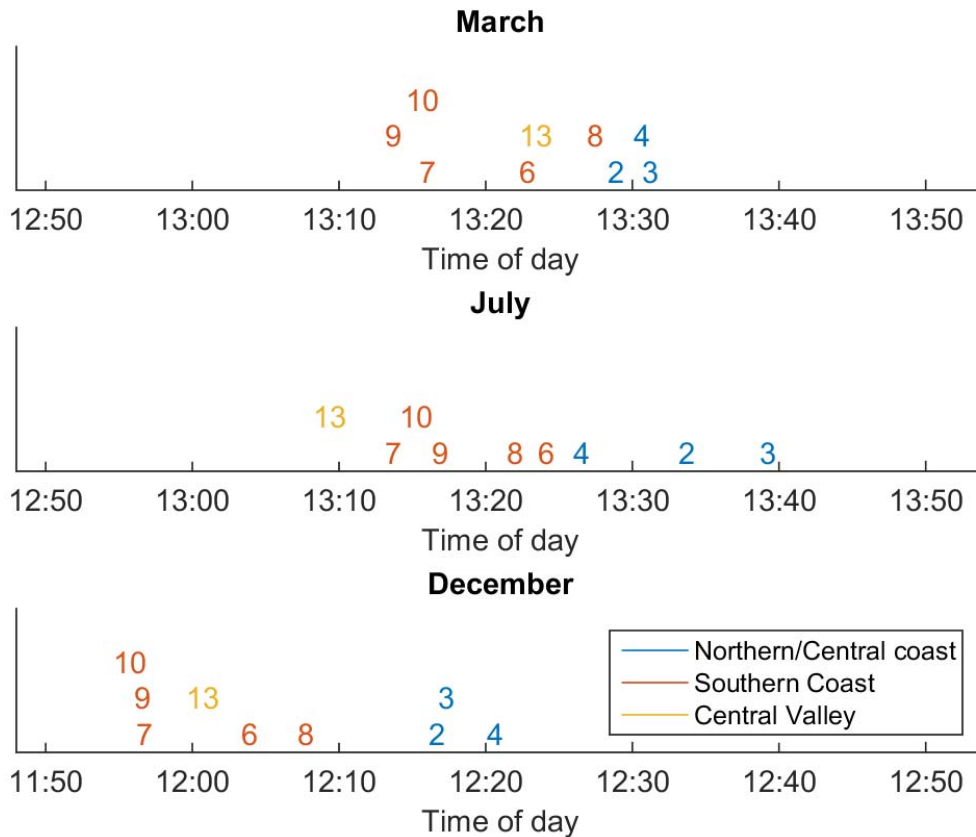


Figure 30. Approximate daily solar peak for south-facing solar in different climate zones with over 30 kW capacity. The purpose of the y-axis is to avoid overlap in zone numbers (y-axis units have no meaning).

Differences in peak solar times translate to differences in the hours of maximum ramp rate. Patterns in the energy production and ramping effects of western-located vs. eastern-located BTM sites are broadly similar to those of west-facing vs. south-facing installations. Figure 31 shows the rate of down-ramps in solar power output during afternoon hours, normalized by energy output, for zones 7, 6, and 3 in March 2013. Zone 3 (San Francisco Bay area and south) is the westernmost and Zone 7 (near the Mexican border) is the easternmost of the three. Figure 31 shows that in hour 19, when

solar power extends and steepens the base of the afternoon net-load ramp, Zone 3 solar has the greatest effect while Zone 7 solar has the least.

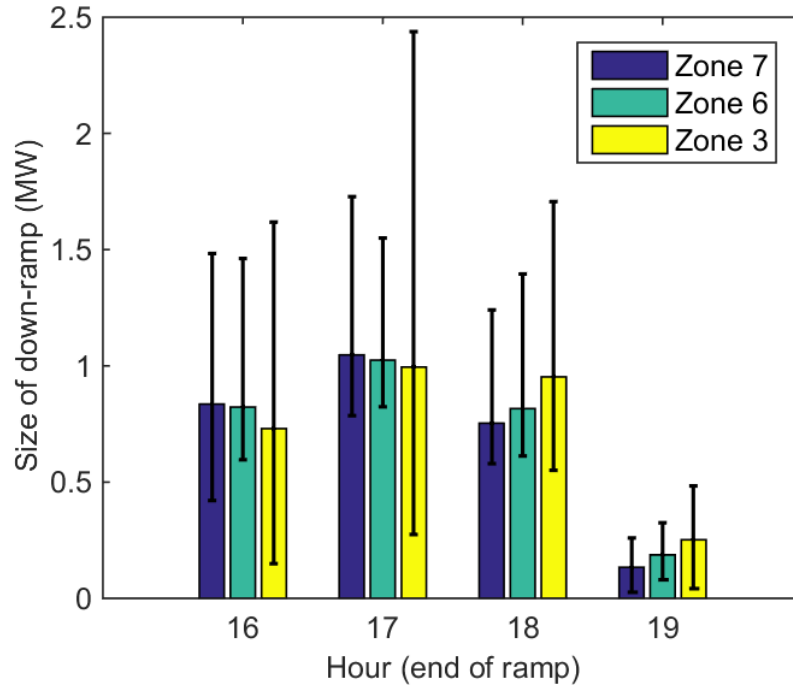


Figure 31. Contribution to the afternoon net-load ramp, in MW per MWh output, for south-facing BTM solar in three climate zones in March 2014. Bars show average values and whiskers extend to maximum and minimum values.

In July (Figure 32), Zone 3 solar, like west-facing solar, has a peak that is better aligned with peak load. In this month, the large down-ramp of Zone 3 solar in hour 19, rather than exacerbating the afternoon net-load ramp, aligns with a decrease in load. In December (Figure 33), Zone 3 solar contributes the most to the net-load ramp rate in hours 16 and 17, previously identified as the most challenging hours that solar affects.

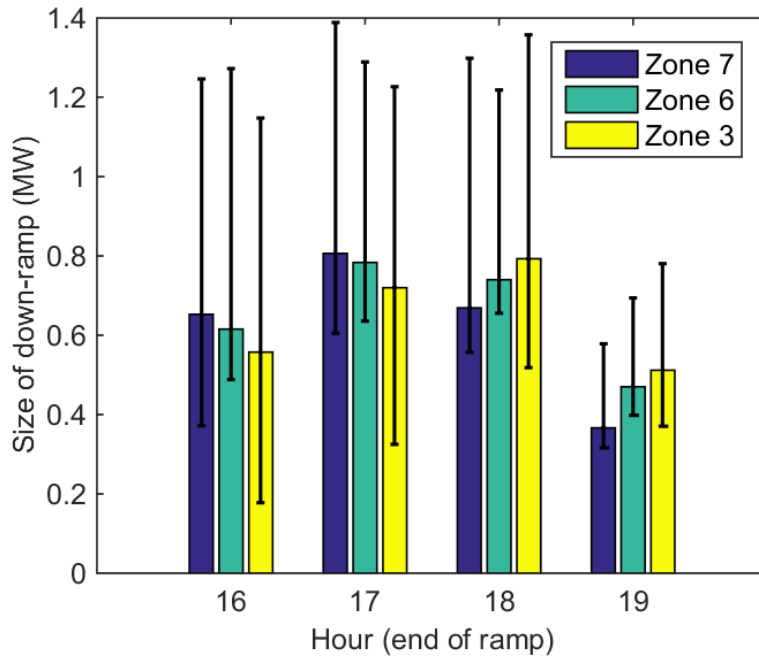


Figure 32. Contribution to the afternoon net-load ramp, in MW per MWh output, for south-facing BTM solar in three climate zones in July 2014. Bars show average values and whiskers extend to maximum and minimum values.

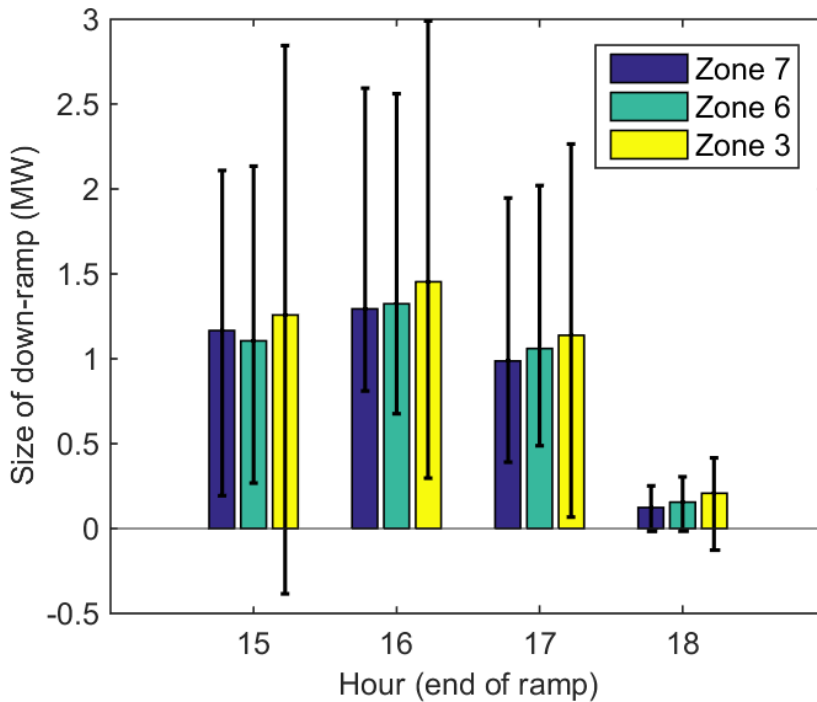


Figure 33. Contribution to the afternoon net-load ramp, in MW per MWh output, for south-facing BTM solar in three climate zones in December 2014. Bars show average values and whiskers extend to maximum and minimum values.

Taken together, these results show that western-located BTM solar has the same broad effect on net-load patterns as west-facing solar. In the winter and spring, it increases energy production in the afternoon but also increases the net-load ramp rate. In July, it reduces peak net load without significantly increasing the net-load ramp rate. BTM solar in Zone 7, in the service territory of SDG&E, exacerbates the afternoon net-load ramp rate to a lesser degree than BTM solar in Zone 3, in the service territory of PG&E.

In addition to differences in the timing of peaks and ramps, solar output of different building climate zones varies by capacity factor and volatility of power output. Figure 34 shows monthly capacity factor and coefficient of variation (standard deviation divided by mean, for solar output during hour 12) for south-facing solar by climate zone. As indicated in the figure, higher capacity factors and lower coefficients of variation indicate a better resource.

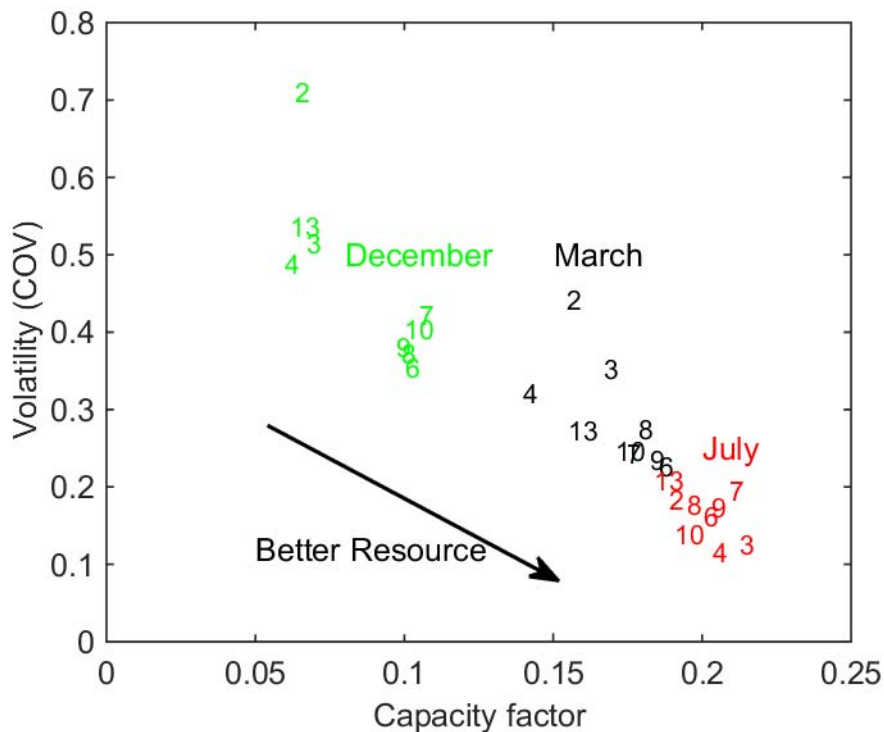



Figure 34. Capacity factor and coefficient of variation for the south-facing BTM solar sites in each building climate zone (with more than 30 kW).

In both December and March, Zones 2, 3, 4, and 13 have the lowest capacity factors and greatest volatility. These sites are located in the western third of the state and north of Santa Barbara (see Figure 29). Volatility of solar power output in northern sites is greater than that in southern sites, reflecting more variable winter/spring weather patterns in the north. In July, capacity factors and volatilities are more similar among zones, although sites near the central coast and slightly inland (Zones 3 and 4) tend to show the best performance.




In the winter and spring, Zones 6 through 10, in the southern coastal area, have consistently high capacity factors and low volatilities relative to other zones (in July Zones 3 and 4 perform slightly better). The previous section showed that solar output from Zones 6 and 7, due to their relatively eastern locations, contribute less to the afternoon net-load ramp rate than Zone 3. Zones 8, 9, and 10 are near Zones 6 and 7. Combined, these results show that BTM solar power output from Zones 6 through 10 tends to have higher capacity factor, lower volatility, and less of a negative effect on the afternoon net-load ramp than Zones to the north. This result provides support for policies to incentivize BTM solar in Zones 6 through 10, assuming daily load patterns hold constant.

3.8 Energy storage can flatten daily net load and support other renewables grid integration functions

Energy storage is seen as a key technology resource to enable higher levels of solar PV generation to be integrated into electric power system. Despite its ability to enable renewables integration, storage penetration has not yet kept up with the growth of renewables in California. Assembly Bill 2514 requires load-serving entities to procure energy storage systems that are cost-effective. As renewables penetration continues to increase, it will increase the value of storage and in turn incentivize its deployment. Wholesale market prices and utility tariffs, particularly demand charges on commercial customers, incentivize a shift in net load from its early evening peak to mid-day.

Transmission-connected energy storage systems can participate in wholesale energy and ancillary services markets. In the energy market, storage charges in the middle of the day when prices are at their lowest daily levels (sometimes even negative due to high solar production and over-supply conditions), and then discharges in early evening when prices are higher. This profit-maximizing strategy in effect flattens daily net load by shifting energy from a time of abundance to a time of scarcity. As the RPS increases beyond 33%, over-supply and negative prices in the middle of the day will become more common. This will allow storage systems to increase their revenue as conditions allow more occurrences when charging is paid, or as the marginal price differential between over-supply and peak load timings increase. In addition, storage has the ability to provide ancillary services, such as regulation, spinning and non-spinning reserve, fast ramping and capacity resource reserve, to earn revenue and further support renewables integration.

Distributed storage that is co-located with solar PV can be sited on the customer side of the meter or on the utility side. Storage that is sited on the customer side can enable bill savings, increase reliability, and potentially participate in capacity resource and demand response programs. By maximizing bill savings and revenue through retail time-of-use rates and demand response programs, customers are incentivized to shifting their net load from peak hours to non-peak hours. When sited on the utility side, energy storage can be used to defer large capital expansion project on the utility system via peak



shaving, as well as provide other benefits such as increasing distribution system reliability and enhancing power quality.

DNV GL recently analyzed a use case for distributed-connected storage operated as a shared asset between behind-the-meter customer and utility¹². The report concluded that the utilization of customer-owned assets for distribution system support and grid reliability services will enable a large volume of assets to be utilized for grid support at low incremental cost to the utility. This will incentivize installation of distributed energy resources for customers or third party vendors, lowering the existing financial barriers and promoting higher penetration of clean renewable resources at optimal locations within the electric grid. Most importantly, autonomous devices can be coordinated and managed for grid support, enabling grid operators to effectively mitigate issues associated with high penetration of renewable resources within the distribution system.

4 CONCLUSIONS


Analysis of 2014 BTM and grid-scale solar power data showed that solar power is effectively reducing summer peak net load, avoiding emissions and reducing system costs during these hours. Given current daily load shapes, however, the ability of solar power to reduce peak net load further is limited. High-demand hours will have to be shifted to earlier in the day in order for solar power to provide additional benefits in peak reduction.

Solar power in California is reaching high enough penetration to reduce winter minimum net load. While current levels are unlikely to require mitigation, continued fast growth in installed solar capacity could require storage, curtailment, or load-shifting during mid-day hours in order not to violate constraints such as minimum power production of conventional generators.

In the winter and spring, solar power is increasing the overall magnitude, and in some cases the rate, of the afternoon net-load ramp. Unless daily load patterns are re-shaped, this effect will require increased deployment of fast-ramping resources so that supply keeps pace with demand in the afternoon. In the near term, this service will likely be provided primarily by fast-ramping gas turbines, potentially reducing some of the air quality benefits of solar power. Increased amounts of storage or demand response could provide this service with minimal environmental impact.

Analysis of 2014 historical data shows that west-facing solar may have benefitted the current system to a greater extent than south-facing solar by more effectively reducing summer peak net load. As solar capacity in California continues to increase, this benefit of west-facing solar may become outweighed by its relatively greater impact on the winter/spring afternoon net-load ramp and daily minimum net-load reduction, such that

¹² Kleinberg, Michael (DNV GL), Rick Fioravanti (DNV GL), Sudipta Lahiri (DNV GL), Warren Katzenstein (DNV GL), Eric Cutter (E3). To be published. *Energy Storage Use Cases Analysis and Technology Maturity and Viability Protocols*. California Energy Commission. Publication Number: CEC-XXX-20XX-XXX.



south-facing solar provides greater system benefits going forward. A combination of west-facing and south-facing solar would provide the most consistent power output throughout the day, and should be analyzed further for future high-renewables scenarios.

BTM solar located in the western part of California, as compared with the southern/eastern part, shows similar daily production patterns to west-facing solar, as compared with south-facing. In addition, BTM solar in southern/eastern California, generally has both higher capacity factor and lower volatility than solar in northern/western California, indicating that it supplies more and better-quality power output.

Strategies to address the challenges introduced by BTM solar include large-scale deployment of energy storage, dispatchable demand-response, and time-of-use rates for consumers. Further study is needed to determine the effects of these strategies and guide policy on deploying them to maximize environmental quality, cost-effectiveness, and grid reliability.

The purpose of this report was to isolate the current effects of solar power, especially BTM solar, on net load in California. While its results indicate the benefits and challenges of integrating larger amounts of solar power, and demonstrate the contrast between west-facing and south-facing solar, further study from a system-wide perspective is needed to quantify the benefits and costs of increased solar capacity and plan for the integration of larger amounts of solar power. Adoption of customer incentives to shift load, fast-acting demand response, diurnal energy storage, transmission and generation planning to increase grid stability at low net loads, and development of wind resources with low correlation to solar power output are all factors that need to be considered in planning for high renewables scenarios. The recent CPUC whitepaper, "Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future," gives the full context of available policy solutions to ensure that the future renewables-based grid provides clean, reliable, and cost-effective power to California.



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