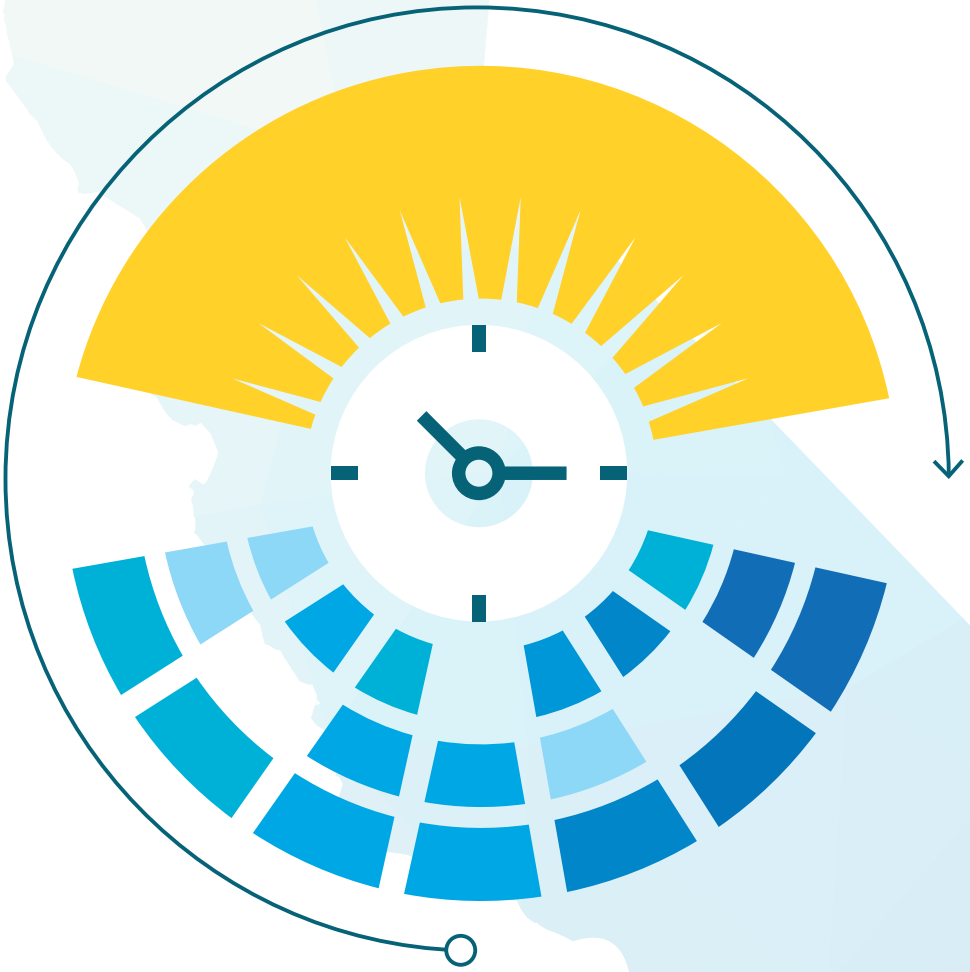
BREAKTHROUGH INSTITUTE

QUANTIFYING SOLAR VALUE DEFLATION IN CALIFORNIA



EXECUTIVE SUMMARY

Solar photovoltaics (PV) have been a remarkable clean energy success story, with prices falling by a factor of ten and world solar generation increasing 21-fold over the past decade.[1,2] Solar serves as the best example we have for making clean energy cheap and represents the cheapest source of new electricity generation at the margin in much of the world today. Solar will be one of the largest drivers of decarbonization globally over the next decade and may prove to be the single largest source of new electricity generation over the course of the 21st century.[3]

However, the fact that solar generation is concentrated in a relatively short period of the day means that it is particularly susceptible to a phenomenon known as value deflation. As more solar generation is installed, the average wholesale price of electricity decreases during mid-day hours. This reduces the value of both new and existing solar compared to other electricity sources that are a better match to net load or have a different generation profile.

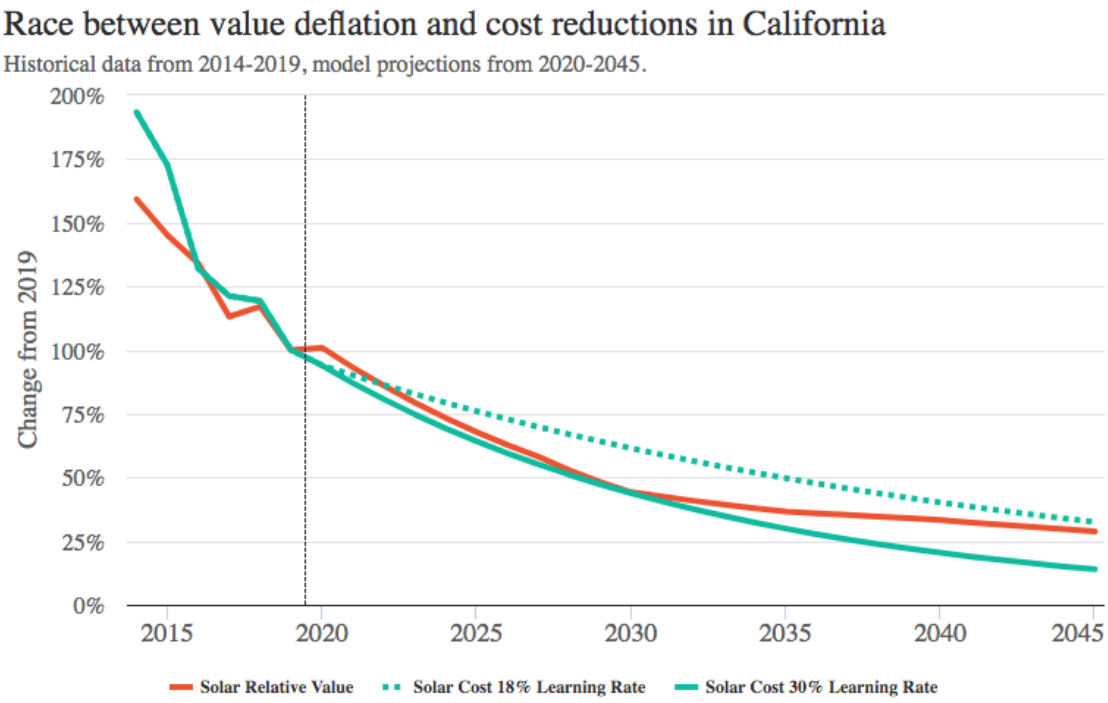
As a result, we find that some degree of future subsidies — either in the form of current tax incentives or future nominally technologically-neutral mechanisms like carbon pricing or a clean energy standard — will likely be needed to sustain cost-effective deployment of the high levels of solar over the next three decades projected by the California Energy Commission.[4] This is likely to be the case even if value deflation can be in part mitigated by the expansion of complementary technologies like long-distance transmission, storage, and demand response.

California is a world leader in solar generation, with around 20% of its electricity coming from solar — substantially higher than any other US state or country in the world. It is also a place where the effects of value deflation are being felt more acutely. In California, declining midday power prices have significantly reduced the value of solar — particularly in the Spring and Fall months when solar generation is high and system load is lower. By analyzing six years of hourly generation and price data from the California Independent System Operator (CAISO), we find that the value of solar has fallen by around 37% since 2014 relative to other sources of electricity generation.

Observed value deflation is even more pronounced — at around 50% — in the Spring months, where negative daytime electricity prices and high levels of solar curtailment are increasingly common. In the Summer months, by contrast, value deflation has been limited to around 20%,

as periods of high solar generation tend to better coincide with periods of high overall load, given the high cooling demands in parts of the state.

Value deflation to date has been largely countered by the continued rapid decline of solar PV module costs. Between 2014 and 2020, subsidized solar power purchase agreement costs in California fell by around over 50%, while the unsubsidized levelized cost of energy of solar projects fell by around 65%. There is currently a race between value deflation and cost reductions in California, though which factor will win over the longer term remains an open question.[5] The figure below shows changes in both average annual solar wholesale prices (hereafter referred to as value*; red line) and solar system costs (teal line) in California relative to 2019 values, as well as future projections developed in this report for different potential learning rates and modeled value deflation in a scenario where California meets its SB100 goal of fully decarbonizing the power sector by 2045.



Historical and future solar value (red) and costs (teal) using both 18% and 30% learning rates, shown relative to current (2019) values for both. Note that these relative cost and value trajectories are the same for both subsidized and unsubsidized solar costs. For more details, see part four of this report.

*We refer to wholesale prices as "solar value" in this report to make it clearer what is meant by value deflation. However, we recognize that there is value provided by solar – e.g. its low-carbon emissions – that are not currently reflected in wholesale prices.

The value of utility-scale solar PV in California in 2020 was approximately $27 per megawatt-hour (MWh) sold, similar to the price paid to solar producers of $26 per MWh in power purchase agreements (PPAs).[6] However, the actual levelized cost of energy (LCOE) generation from solar was around $45, which is around 40% higher than the PPA costs due to the combination of a 30% federal investment tax credit (ITC), various state-level incentives, and indirect investor subsidies.

California solar is currently subsidized by around $900 million per year, based on the difference between PPA and LCOE costs. While future solar costs are expected to reasonably keep pace with value deflation if the ratio of PPA to LCOE remains constant — e.g., if future subsidies remain at current levels — the same is not necessarily true for unsubsidized solar costs. That said, the overall cost of the continuation of solar subsidies would likely remain somewhere between current levels and twice current levels, as higher levels of solar installation will be counterbalanced by falling per-MWh subsidies due to declining solar system costs. We additionally find that an effective carbon price of around $30 per ton CO2 would be similar to the continuation of current solar subsidies in California.

Value deflation of solar can be at least partially mitigated by the deployment of complementary technologies: grid-scale storage, long-distance HVDC transmission, and load shifting through efficiency and demand response. The use of clean firm generation can also help reduce overall system costs at high levels of solar penetration, reducing the solar capacity required to meet demand year-round due to seasonal differences in output.[7] Value deflation will likely prove more problematic in a first-mover like California than in other later solar adopters, given the already-high levels of solar penetration and ambitious near-term expansion plants.

This report provides a detailed analysis of both historical and projected future value deflation of utility-scale solar in California and is divided into four parts. The first looks at the expansion of solar in California over the past six years, daily and seasonal variation in generation, and how California's generation mix changes with different levels of solar generation. The second part quantifies how the value of solar has changed in California, both across different hours and seasons of the year and over multiple years. The third part develops a statistical model to evaluate future seasonal and annual value deflation as the percent of solar generation increases. Finally, the fourth part looks at how subsidized and unsubsidized solar costs and values might change through 2045 in a world where California meets its SB100 goals and explores the role of complementary technologies in mitigating value deflation.

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PART ONE: CALIFORNIA'S SOLAR EXPANSION

California has been a world leader in solar photovoltaic generation, with a higher percentage of electricity coming from solar than any other large subnational region or nation. This makes it a useful case to examine the impacts of relatively high levels of solar generation on the grid, providing a look at some of the challenges that other regions might face as they expand their solar generation.

Table 1: 2019 Solar PV Generation Percent[8,9]	
California	**19.2%**
Nevada	13.1%
Hawaii	12.7%
Italy	8.6%
Greece	7.9%
Germany	7.8%
Chile	7.5%
Japan	7.3%
Australia	6.8%
US	2.5%

In 2019, California got around 19% of in-state electricity generation from solar electricity (see Table 1). The next highest state was Nevada at 13%, with the highest share country — Italy at 8.6% — having less than half the level of solar generation as a percent of production. Germany, which led the world in installing solar back in the 2000s and has an economy only a bit larger than that of California, got only around 8% of its electricity from solar in 2019.

In California, approximately two-thirds of solar generation occurs at utility-scale facilities, while the remaining third is small-scale residential and commercial generation, primarily from rooftop panels.[10] These annual numbers can obscure just how much solar generation occurs in California on a day-to-day basis. Solar only generates power when the sun is shining — and generates the most during the middle of the day. Solar represents closer to 40% of generation on average during the daytime, and even more during lower-demand Spring and Fall months.[11]

Figure 1, below, shows the electricity generation by source for a week in March 2019 in the California Independent System Operator (CAISO), the organization that runs the electricity market across California's major utilities and manages 80% of California's electricity[12]. The variable renewable energy sources — solar and wind — are shown at the top of the generation "stack." Thermal energy — largely from natural gas — and imports (also mostly gas) from neighboring states are able to ramp generation up or down to fill in the gaps around the variable renewables. Nuclear and firm renewables like geothermal mainly serve as always-on baseload generation. Hydroelectric dams are more flexible, with an ability to ramp up or down generation that is determined in part by other water resource requirements.

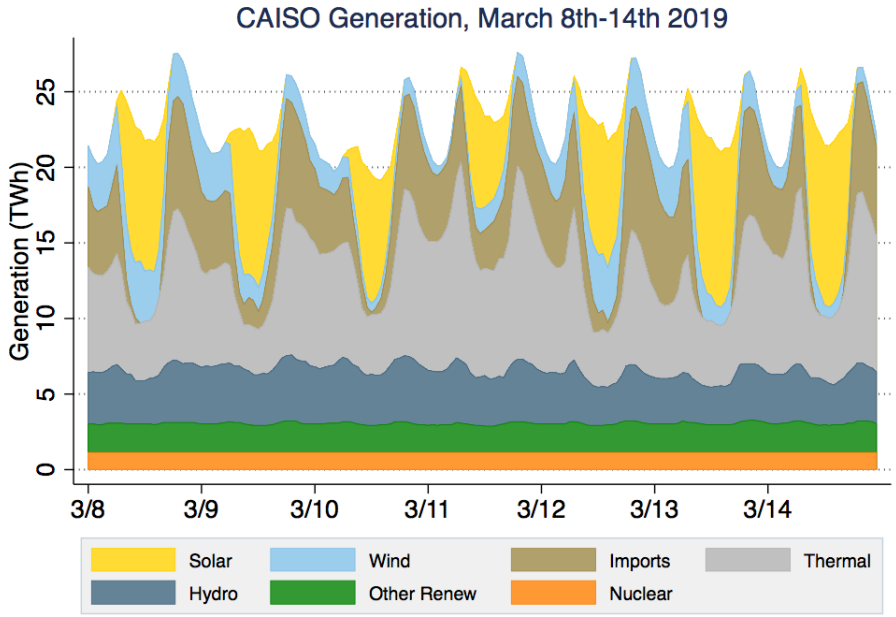

Figure 1: CAISO hourly generation mix for the week of March 8th-14th 2019. Note that solar and wind generation shown are inclusive of curtailment. Solar only includes utility-scale generation facilities.

The solar generation in this figure only includes utility-scale wholesale solar included in the CAISO market and not small-scale, primarily rooftop solar installations that account for about a third of California's solar. Combined utility-scale and rooftop solar represented 19% of total electricity generation in California in 2019. However, utility-scale solar only represented 13% of the generation in the CAISO market. The analysis in this report focuses on the CAISO market, as both hourly generation and price data are available and generally excludes an analysis of rooftop solar unless otherwise noted. That said, both load profiles and prices are impacted by

small-scale, "behind the meter" systems; the dips in total load in Figure 1 during the daytime reflect the impact of small-scale generation.*

Utility-scale solar generation in CAISO has expanded rapidly over the last five years, from around 5% of generation in 2014 to 13% today. Much of this expansion happened between 2014 and 2017, with utility-scale solar generation remaining roughly flat between 2018 and early 2020, as shown in Figure 2 below. This is in part due to CAISO member utilities meeting their 2020 33% renewable portfolio standard (RPS) goals a few years early;[13] the 2018 SB100 legislation will require a 44% target by 2024, likely resulting in higher levels or renewable installations in the next few years.[14]

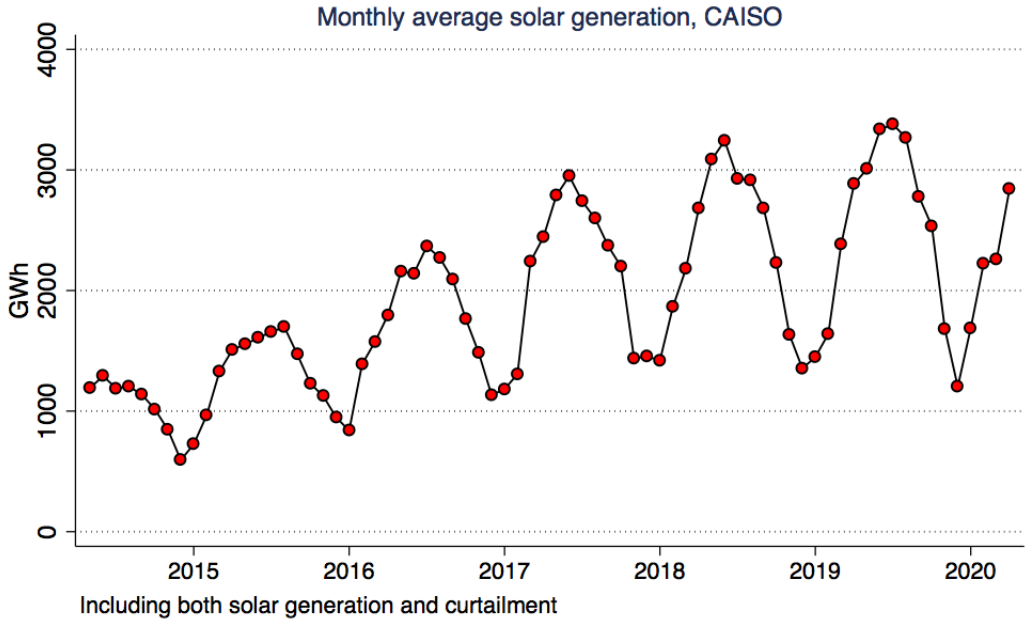

Figure 2: CAISO monthly average solar generation (in gigawatt-hours) for the period from May 2014 through March 2020, inclusive of curtailment.

Solar panels generate notably more electricity in sunny summer months than in winter months in California due to a combination of shorter days and more cloudy conditions during the winter. CAISO solar data shows that generation in November-January is typically around half that of summer months like June-August. This seasonal variation in generation creates some challenges at high solar penetrations; while overall CAISO net load is around 20% lower in the

*Note that total CAISO load excludes behind-the-meter small scale solar, which appears as reduced load in the data.

winter than in the summer, this is much smaller than the ~50% difference in mean solar output between the seasons, as shown in Figure 2. While short-term storage technologies have made some strides in recent years, seasonal storage technologies outside of pumped storage hydro — which has a limited ability to expend — are much more nascent.[15]

Figure 3, below, shows the percentage of CAISO monthly generation coming from solar between 2014 and 2020. Solar penetration is the highest in April-June, as this is a period with both high insolation and relatively low cooling demand. In July-August, solar penetration declines as overall load increases due to high cooling demand — particularly in Southern California — while solar penetration is the lowest in the winter months when generation falls due to lower insolation.

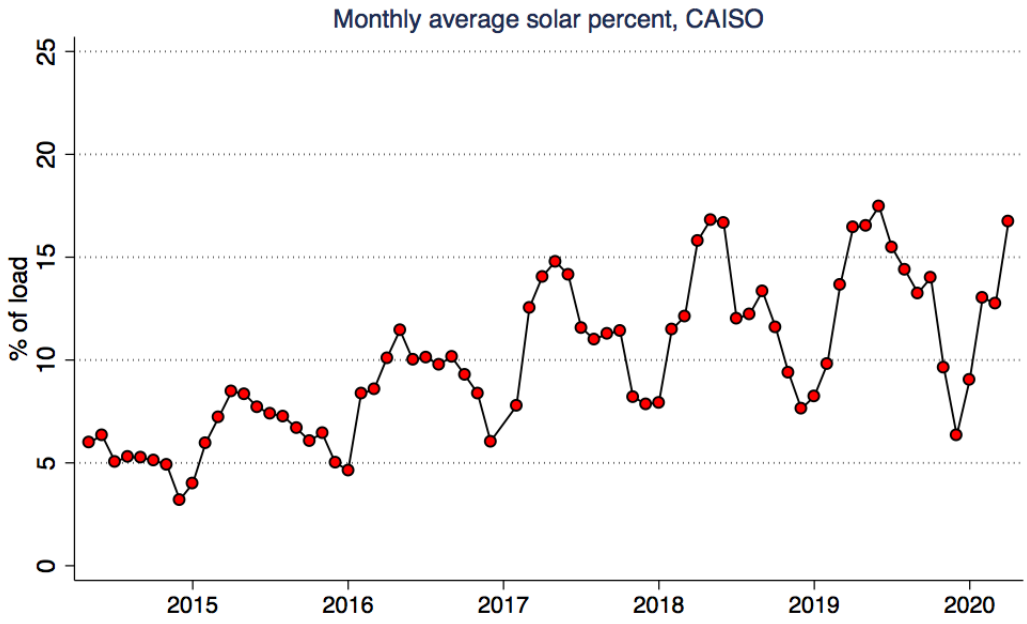

Figure 3: CAISO monthly solar penetration as a percent of net load for the period from May 2014 through March 2020. This figure excludes any curtailed solar generation, as curtailment is not included in net load.

These monthly average generation numbers obscure the magnitude of variation in solar generation across the day. Figure 4, below, shows the average solar penetration by hour of the day between 2015 and 2019. Solar generation is next to zero prior to 7 AM; after that point, it rapidly ramps up, entering a midday plateau that lasts from 10 AM to 3 PM, before declining down close to zero by 7 PM (and by 5 PM during winter months). Midday solar penetration

(excluding curtailment) has increased notably since 2015, when it was only around 18% of CAISO's total load, to around 36% in 2019.

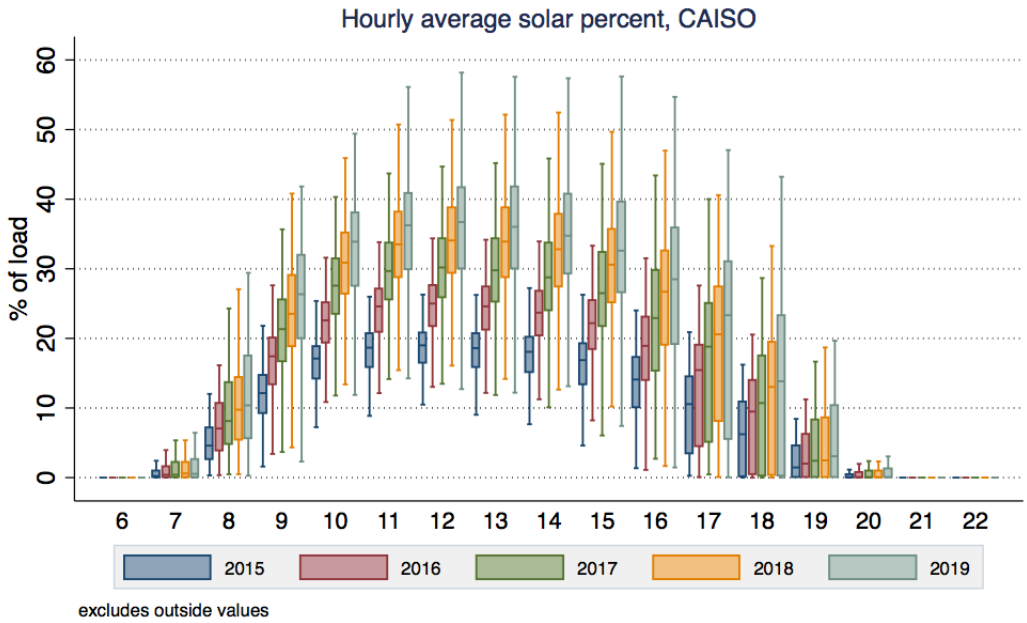

Figure 4: Box plot of CAISO hourly average solar penetration as a percent of total load by year from 2015 through 2019 (where complete years of data are available). The median value is shown by the horizontal lines; bars represent the interquartile range (25th to 75th percentile) while whiskers represent the minimum and maximum values (excluding outliers). Solar percentages shown exclude curtailment, as it is not included in total load.

There is also seasonal variation in hourly solar penetration in CAISO; while midday penetration was around 36% on average in 2019, it was 30% during the winter months, 41% during spring months, 37% in summer months, and 36% in fall months.

The hourly cycle of solar generation in California currently requires a high degree of grid flexibility; flexible generation is required to ramp down in the morning as solar generation increases and ramp up in the early evening as solar generation declines. California's current flexible generation needs are primarily being met by natural gas, both in the form of thermal generation within California and by imports from neighboring states. Figure 5, below, shows how the overall CAISO generation mix (using data from each hour between January 2017 and March 2020) changes as the fraction of generation from solar increases from near 0% all the way up to close to 60%.

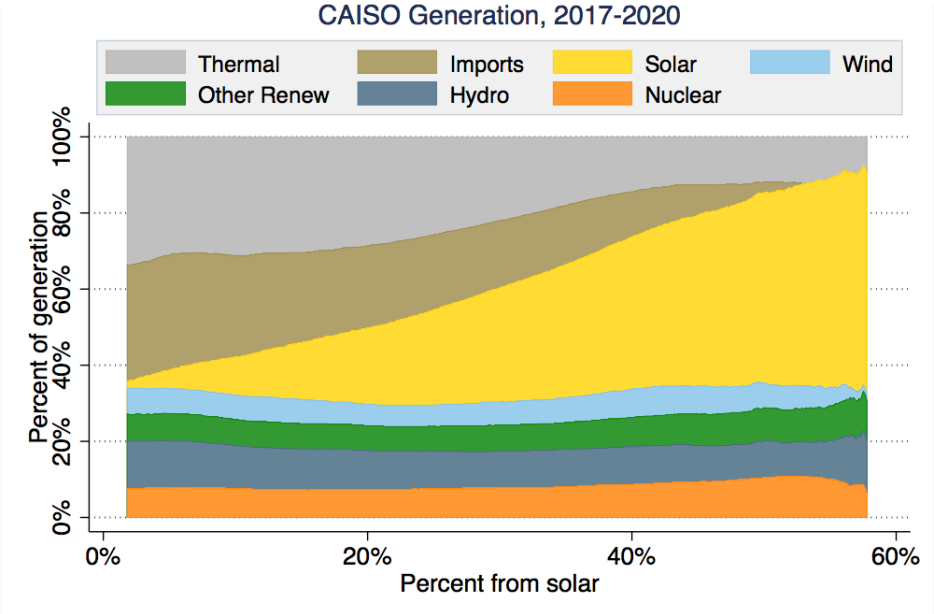

Figure 5: CAISO mean load profile by fuel across a sliding window of 5% solar penetration increased in 0.1% increments, based on hourly data from January 2017 to March 2020. For example, at a solar fraction of 20% the mean of all hours between 17.5% and 22.5% solar penetration is shown. Solar percentages shown exclude curtailment, as it is not included in total load.

Both imports and in-state gas generation (thermal) provide a roughly equal amount of generation on average during periods of low solar output, though imports are generally reduced prior to in-state gas generation at lower levels of solar penetration (e.g. < 20% solar). At around 50% solar penetration relatively few imports remain, declining to zero around 55% solar — after which point California is nearly always a net exporter of solar electricity to neighboring states through the Western Energy Imbalance Market (EIM).[16] Other energy sources tend to be used less dispatchably today, with nuclear, hydro, and other renewable generation remaining roughly constant as a percent of generation as solar penetration increases. Wind is also intermittent, but less predictably so than solar, and tends to be largely uncorrelated with the solar fraction of generation (at least outside of some extreme cases where curtailment plays a role).

Figure 6, below, shows how both in-state thermal generation and exports change as solar penetration increases; the black line shows the mean outcome, while the shaded areas reflect the 5th through 95th percentile of hourly values for each 0.1% increment in solar fraction. It is noteworthy that when the solar fraction approaches 60% of total generation, there is still a chunk of residual thermal generation that remains — even under conditions where substantial amounts of solar generation is being curtailed. Thermal generation rarely falls below 10% of total

generation during any period of time. This is due in part to the need for gas turbines to keep spinning to ramp up in the evening. Imports are nearly always above zero as long as the solar fraction remains below 40%; after that point, imports become increasingly negative, with California exporting as much as 6% of its total generation as solar penetration approaches 60%.

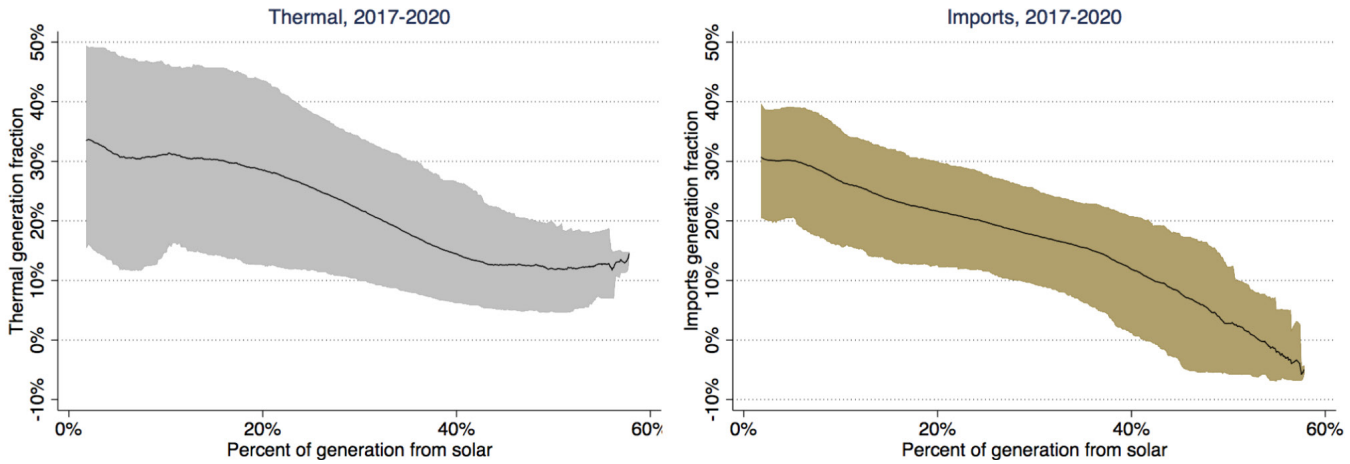

Figure 6: *CAISO thermal and imports load profiles (means and 5th and 95th percentile ranges) across a sliding window of 5% solar penetration increased in 0.1% increments.*

In the future, some of this in-state thermal generation and imports can be replaced by short-term grid storage, which is increasingly being deployed in California. However, despite large drops in battery prices in recent years, battery storage remains a relatively minor player today given the limited deployment to date. Seasonal differences in generation — and the absence of cost-effective seasonal storage technologies — may limit the extent to which solar with battery storage alone can fully displace in-state thermal generation and imports.

The increasing share of solar in CAISO has led to a larger need for firm, dispatchable generation to ramp down in the morning and up in the evening to meet demand. The changing role of firm generation can be seen in graphics of net load — load minus variable wind and solar generation — over the past six years. Back in 2012, a projection of future net load by CAISO was named the "duck curve" due to its resemblance to a duck.[17] CAISO's analysis proved remarkably prescient, with rising levels of solar generating a real-life duck-shaped curve in recent years. Figure 7, below, shows actual CAISO net load for the average March day between 2015 and 2020.

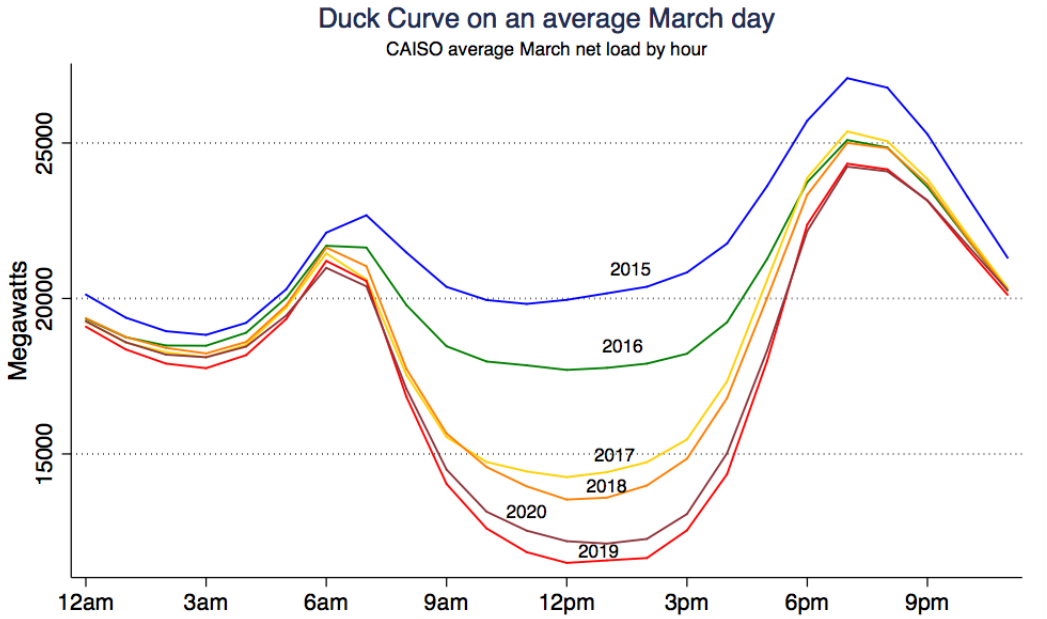

Figure 7: Monthly mean CAISO net load (total load minus wind and solar generation) by hour of the day for March 2015 through March 2020. Note that the y-axis does not start at zero.

A few things stand out when comparing this real-life duck to the 2012 projections. First, net load has fallen a bit faster than predicted, reaching a low of 11,500 MW in the middle of the day in 2019, compared to 13,000 MW in the 2012 projections. Second, the evening net load has modestly fallen rather than rising as predicted, reflecting both the role of additional wind in helping meet some evening demand and the success of efficiency and demand reduction measures in lowering the evening peak.

The "duck curve" poses a number of important challenges for grid management in California. First, it implies that a growing share of dispatchable firm generation is experiencing lower and lower capacity factors, as it is more expensive to operate than fuel-saving, low-marginal-cost solar generation. Second, the slope of the evening ramp has become increasingly steep. This can make the grid more vulnerable to disruptions in in-state thermal generation or imports, as we saw during the brief rolling blackouts in summer 2020.[18]

However, the challenges posed by the duck curve are in principle solvable through the combination of grid-scale energy storage, improved transmission infrastructure, and flexible demand. Energy system models suggest that these can largely smoothly daily variations in variable renewable generation, though there is also likely a need for clean firm generation to enable the

system to effectively deal with extended lulls and seasonal variations in output.[19,20] All of these need a strong focus from policymakers to avoid any additional disruptions or bottlenecks to additional solar deployment going forward.

PART TWO:
THE DECLINING MARGINAL VALUE OF SOLAR

While solar is a variable renewable resource, it is also a very predictable one. Unlike onshore wind, which can experience lulls during nearly any time of the day, solar has a much more consistent generation curve during a given season. While cloudy days can result in some reduction in generation, CAISO solar generally remains within 10% or so of its average monthly output for the vast majority days of the year.*

However, the fact that solar is so concentrated during certain hours of the day means that it is more susceptible to a phenomenon known as "value deflation." In short, at higher levels of solar penetration, wholesale electricity prices tend to become quite low during daytime hours. Adding more solar — and generating more electricity during these low-price periods — further drives down daytime electricity prices, and means that both existing and new generation becomes less valuable over time.** While there are some high-demand periods where solar will remain valuable up to very high penetration — such as hot summer days — there are other periods of time such as spring and fall "shoulder months" where significant value deflation has already occurred. Lower — or even negative — daytime electricity prices are not inherently bad, as they can help reduce overall electricity system costs. However, falling daytime prices reduce the incentive for installing additional solar, while increased daytime curtailment reduces the benefits of currently installed solar generation.

Prior studies have suggested strong value deflation of solar in California; for example, Sivaram and Kann (2016) predicted that the wholesale price of solar would decline by 45% when solar makes up 15% of the total electricity generation, and 69% when it makes up 30% of generation.[21] However, this analysis was based on a 2012 paper, back when solar represented less than 3% of California's electricity generation.

With solar in California now at 19% of total electricity generation (and 13% of CAISO generation), we can assess how these models have played out in practice in recent years. For simplicity, this analysis is based on CAISO-wide marginal energy prices, which exclude node-specific congestion or loss prices. The fairly wide geographic distribution of solar generation should mean that using wholesale marginal energy prices should provide a similar result to a more thorough analysis using node-specific locational marginal prices applied separately to each power producer. However, additional location-specific modeling in the future could provide a clearer picture of the role of congestion and loss in solar value over time.

* Based on an analysis of average daily CAISO solar generation compared to monthly means between 2014 and 2020.

** Non dispatchable firm generation – e.g. baseload – is also negatively impacted by lower daytime electricity prices.

As the percentage of electricity on the grid coming from solar increases, we should expect that the overall marginal prices of all electricity on the grid should decline, as the marginal cost of solar generation is close to zero and a number of other energy generation sources (hydroelectric, wind, other renewables, and nuclear) either have near-zero marginal costs or are cannot easily ramp down generation (as shown in Figure 5). We see exactly this behavior in CAISO data; as the percent of electricity from solar increases from 0% to 55%, the marginal price of electricity falls from around $60 per MWh to $0, as shown in Figure 8, below.

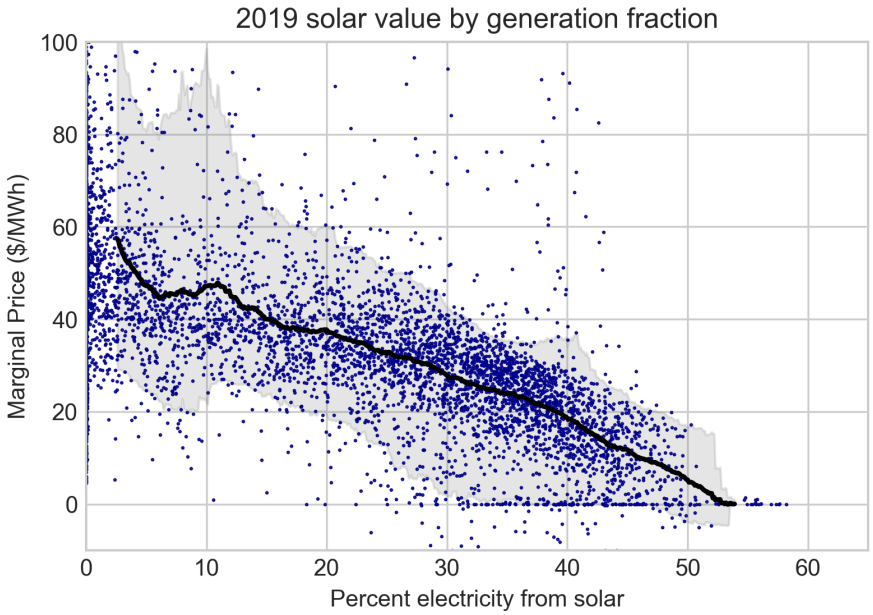

Figure 8: CAISO hourly marginal real-time energy prices as a function of the percent of electricity from solar for all hours in 2019 (blue dots) along with mean (black line) and 5th and 95th percentile ranges (grey shading) across a sliding window of 5% solar penetration increased in 0.1% increments. Solar percentages shown exclude curtailment, as it is not included in total load.

At 30% solar penetration, the marginal price of electricity falls by around 50%. During periods when over 50% of California's electricity is generated by solar, the marginal price of electricity effectively falls to zero and is even negative in some periods as producers are paid not to produce. However, it is difficult to generalize this relationship outside of the data shown, as there are confounding factors from seasonal and time-of-day influences.

For example, periods of near-0% solar generation are predominantly nighttime; a hypothetical scenario of near-zero solar generation during the day would likely result in much higher prices than shown here. Similarly, the extreme values of 55%+ solar percentage only occurred in the Spring (Summer prices were also close to zero around 50% percent solar, while fall and winter prices are closer to $20 per MWh as penetration approaches 50%). Finally, the solar percentage itself can mask large differences in underlying generation. High solar generation in the spring, when demand is relatively low, results in a much higher solar percentage than the same amount of generation in the summer, when demand is higher.

The monthly average solar price in CAISO between 2014 and 2020 can be calculated by multiplying the solar generation for each hour (including curtailment, as generation unused still impacts the cost per MWh generated) by the CAISO-average hourly marginal energy price. The results are shown in Figure 9.

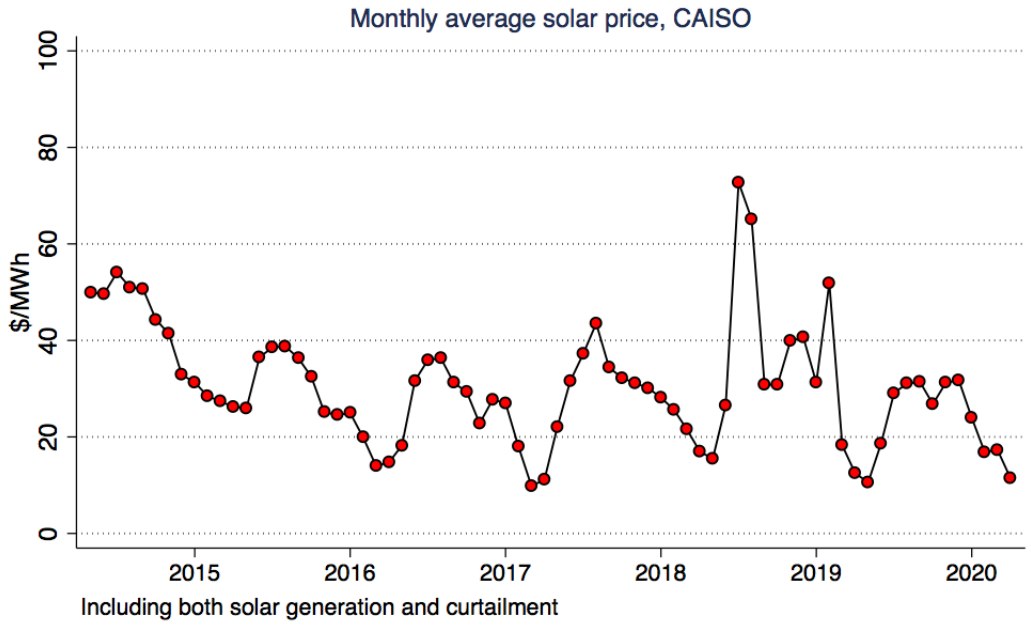

Figure 9: CAISO monthly average solar prices (in $ per MWh) for the period from May 2014 through March 2020, inclusive of curtailment.

CAISO monthly average solar prices fell rapidly between 2014 and 2016 before largely leveling off between 2016 and 2020. However, monthly average solar prices provide a relatively poor measure of value deflation, as they end up conflating the changing value of solar with changes in demand driven by weather conditions, prices of other fuels, and other factors affecting electricity prices.

Rather, value deflation is more accurately assessed by looking at the difference between the value of solar and the value of non-solar electricity on the grid over time.

Figure 10, below, shows the CAISO monthly average price for solar, average generation, and average non-solar generation (calculated by multiplying the hourly non-solar generation by the hourly average marginal price). Both follow similar patterns over time, with large drops in price between 2014 and 2016, though non-solar prices have increased modestly since 2016 while solar prices have remained relatively flat.

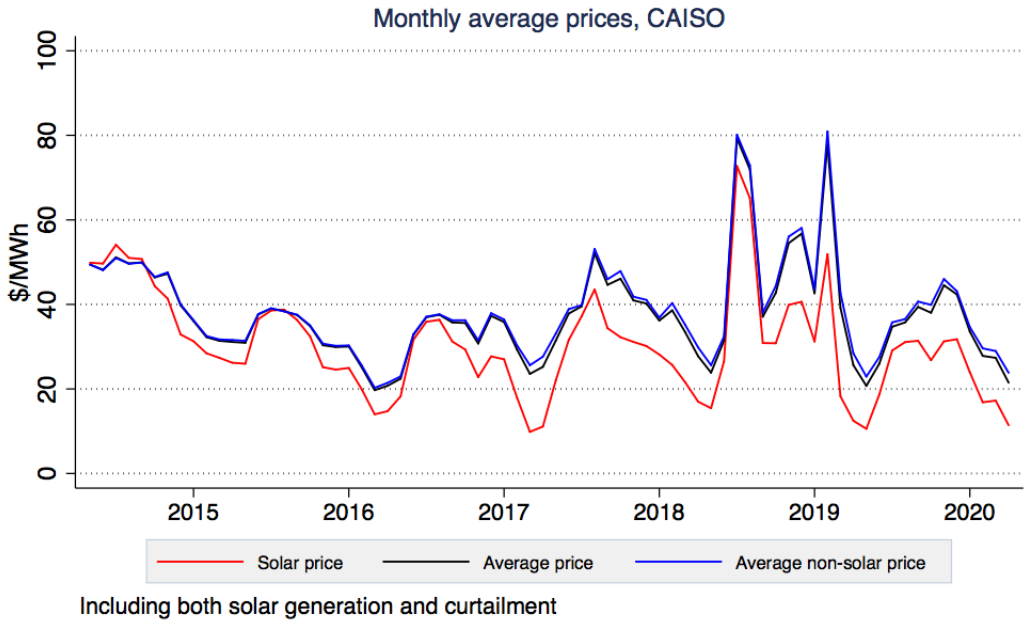

Figure 10: CAISO monthly average solar prices (in $ per MWh) for the period from May 2014 through March 2020, inclusive of curtailment.

We can calculate the value deflation of solar over time by looking at the difference in value between non-solar generation and solar generation. While looking at the difference between solar value and the value of all generation would provide a similar result over the 2014-2020 period, the same would likely not be true at much higher levels of solar deployment (when solar generation would constitute a sizable portion of average generation, and would thus complicate

the calculation of solar's relative value). The difference between solar and non-solar prices is shown in Figure 11.

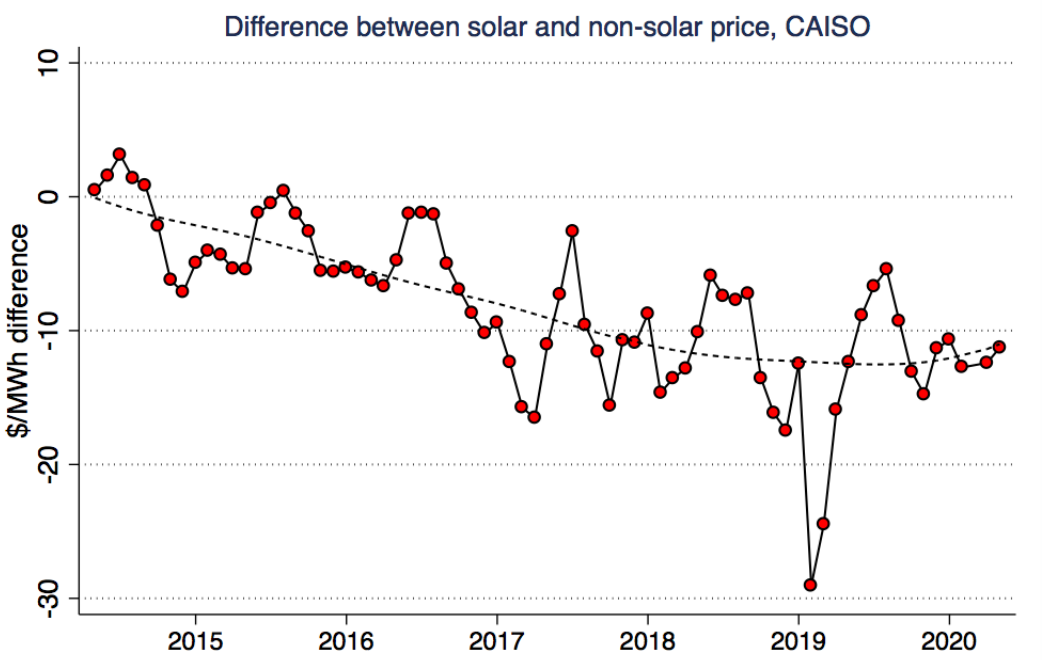

Figure 11: Difference between solar and non-solar CAISO monthly average electricity prices (in $ per MWh) for the period from May 2014 through March 2020, inclusive of curtailment.

Even this is a somewhat imperfect metric, as the difference between solar and non-solar prices can be affected by both value deflation and by exogenous factors that influence the overall price of electricity (e.g. periods of high electricity prices could have a larger absolute gap between solar and non-solar prices even if the relative difference is similar). To normalize for this, we choose to

express value deflation as the percent difference between solar and non-solar prices over time in CAISO, as shown in Figure 12.

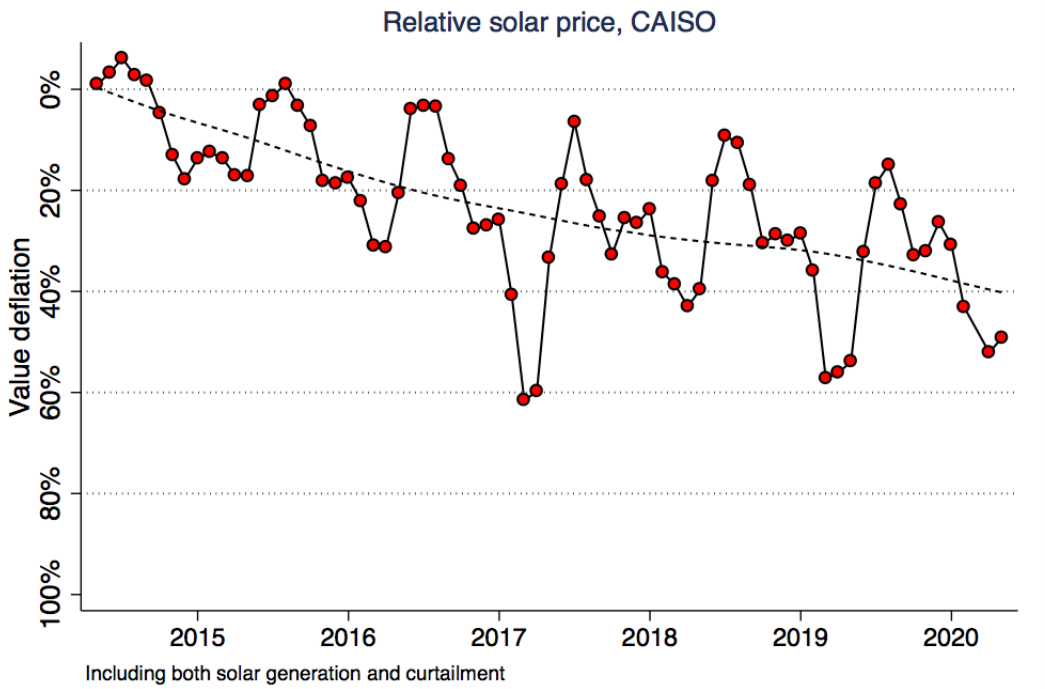

Figure 12: Monthly mean solar value deflation in CAISO for the period from May 2014 through March 2020, inclusive of curtailment, calculated as the percent difference between solar and non-solar prices electricity prices.

We find a notable seasonal cycle in observed CAISO solar value deflation. The largest declines in solar value are seen in the March-May period, when overall electricity demand is low but solar generation is relatively high; in recent years, value deflation has been between 40% and 60% during these months. The smallest declines in solar value happen in July-September, when both solar generation and electricity demand are high, and cooling requirements tend to align the timing of maximum demand with that of maximum solar generation. During these summer months value deflation is only between 10% and 20% in recent years.

Overall solar value has declined by around 37% since 2014, during the period when solar has grown from 5% to 13% of total CAISO generation (and increased from 7% to 19% state-wide). This is similar to what other models have previously predicted. For example, Hirth (2013)[22] calculated that value deflation would be roughly 35% between those two levels of deployment, though it is a bit lower than the 45% deflation suggested by Sivaram and Kann (2016).[23] A recent

report by BloombergNEF also finds a similar 30% value deflation between 2014 and 2020.[24]

Value deflation is expected to continue in the future as the percentage of electricity generated by solar continues to grow. At the same time, there is a growing awareness that complementary technologies such as energy storage and long-distance HVDC transmission can help reduce value deflation by utilizing excess midday generation, either by storing it for later use or exporting it to regions with more limited solar or where solar generation is lower due to time zones, provided sufficiently improved grid infrastructure such that California's solar could help meet evening peak demand in the central or even Eastern US. In the next section we use the historical relationship between solar generation and prices to develop a statistical model of future value deflation. As the model assumes current grid dynamics remain fixed, it provides a worst-case estimate in the absence of the deployment of complementary technologies.

PART THREE: MODELING FUTURE VALUE DEFLATION

To model the effects of different levels of solar penetration on CAISO electricity prices, we fit a multivariate regression model to predict the price of electricity using hourly CAISO data between May 1, 2014 and May 16, 2020. This allows us to fit a model to 52,986 individual hours of system-wide generation and price data. The model we chose is:

$$Y = \beta_0 + \beta_1 \cdot load + \beta_2 \cdot load^2 + \beta\ (hour_C\ , season_C) + \beta\ (hour_C, season_C, solar)$$

Here the price of electricity for any given hour (Y) is a function of both the load and the load squared (to reflect non-linearities in pricing under high or low load conditions). It also includes the interaction between categorical variables representing the hour of the day and season of the year ($hour_C$, $season_C$), and categorical hour of the day and season of the year variables and a continuous variable for solar generation ($hour_C$, $season_C$, $solar$). This allows the model to estimate the effect of solar generation on electricity price separately for each combination of hour of the day and season of the year. The model includes 183 degrees of freedom across all the variables.

We additionally restrict the model to prevent electricity prices from going negative in the future, assuming that any solar generation during periods of negative prices will simply be curtailed. In practice there may be modest future negative prices — as are experienced occasionally today — but it is hard to predict exactly how they will evolve in the future. The alternative — allowing unconstrained negative prices — creates unrealistic outcomes when projecting out-of-sample. Generation and curtailment when electricity prices reach zero in the model are treated the same, as our definition of value deflation is inclusive of curtailment.

To test how effectively the model simulates observed solar value deflation, we used it to predict the price of electricity for each hour in our dataset and calculated the modeled value deflation (monthly average solar price as a percent of monthly average non-solar price) for each month between May 2014 and May 2020. Figure 13, below, shows the observed value deflation in black (from Figure 12) as well as model projections in red.

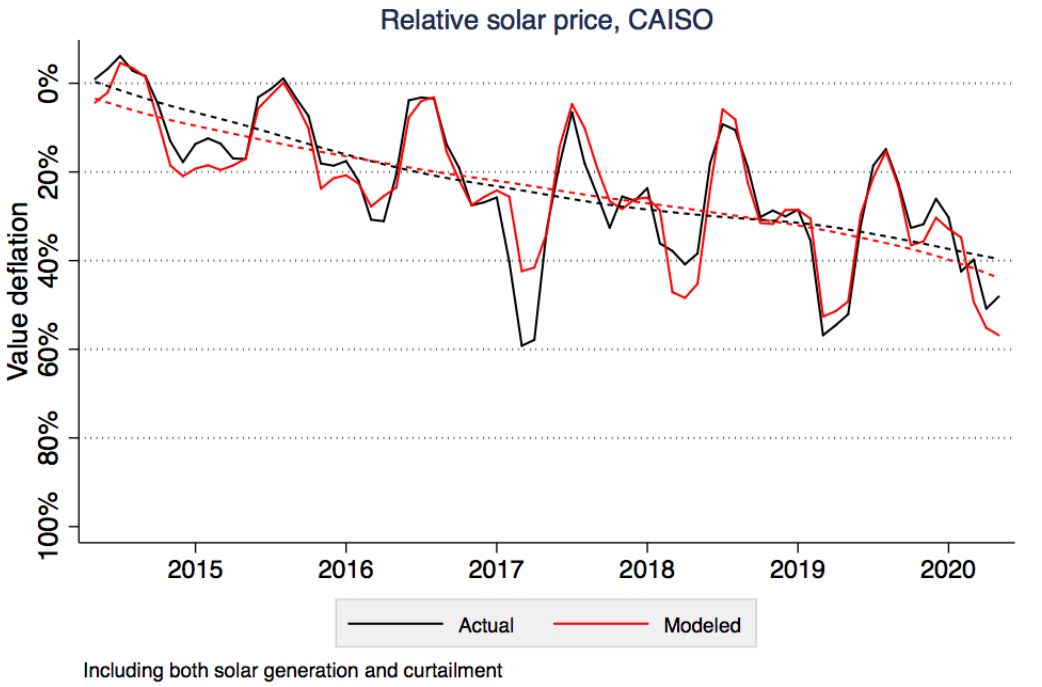

Figure 13: Modeled and observed monthly mean solar value deflation in CAISO for the period from May 2014 through March 2020, inclusive of curtailment, calculated as the percent difference between solar and non-solar prices electricity prices.

While the model generally captures the change in value deflation over time — as well as the seasonal cycle — there are some differences that stand out. Specifically, the model underestimates value deflation in February-April 2017 and overstates value deflation in March-May 2018. In general, model and observation disagreements are largest in the first few months of the year, though it is unclear what factors are driving these differences.

The model can be adapted to simulate what prices would be under higher levels of solar penetration than currently exist within CAISO. To do this, we apply the regression coefficients derived from the full dataset to the most recent year in which we have full data available (2019) while scaling up or down the solar fraction but keeping the overall system load fixed. Solar generation (including curtailment) at all times will generally change proportionate to the annual solar generation percentage; in other words, doubling the current solar penetration would effectively double the current solar generation in each hour of the year. This requires assuming that newly installed solar technologies do not have substantively different generation profiles than currently installed technologies, though we suspect this is likely to hold at least for the near-future.

Figure 14, below, shows the actual solar value deflation observed in CAISO in 2019 (dashed black line) by month compared to the model projection at 2019 levels of utility-scale solar penetration (13%; solid black line). It also includes model simulations where the CAISO utility-scale solar penetration is set to 20%, 30%, 40%, and 50% (colored lines).

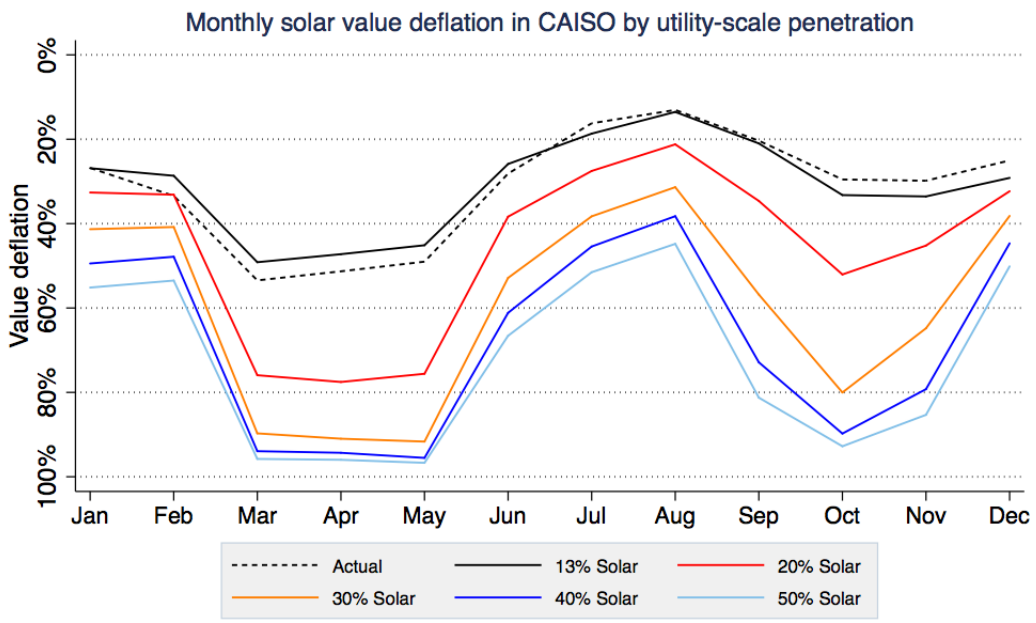

Figure 14: Modeled and observed monthly mean solar value deflation in CAISO for the year 2019, inclusive of curtailment. Model simulations show monthly value deflation at various levels of annual average CAISO utility-scale solar penetration.

A few notable results stand out in this analysis. First, value deflation happens much more rapidly in the shoulder (fall and spring) months than in the summer or winter months. As discussed earlier, this is due primarily to higher summer demand that tends to align with solar generation due to cooling, making summer months more resistant to value deflation. Much lower solar generation in the winter has similar effects. Solar value deflation is already much higher in shoulder months in the observational data, and the model projects that it will fall rapidly, increasing from around 45% to 75% in the spring months and 35% to 45% in the fall months as solar penetration increases from 13% to 20%.

Second, as solar penetration approaches 30%, the solar value deflation in the spring months (March, April, and May) approaches 90%. This is because low demand and high solar production lead to solar generating more than 100% of total demand during most of the daylight hours.

However, at 50% solar penetration value deflation does not reach 100%. Even when curtailment is the norm and prices are near-zero for most of the day, there are still occasional high-demand periods or shoulder hours when solar generation is more limited and additional solar provides some value (though this might change if the model allowed for negative prices or curtailment costs). Conversely, even at 50% solar penetration we see much more limited value deflation in summer and winter months, with value deflation of only around 55%.

Third, because electricity prices tend to be highest in the summer and lowest in the spring (following load more broadly), the periods when value deflation tends to be the largest also tend to be when average electricity prices are the lowest. This means that while value deflation may have a very large impact on seasonal prices, the overall annual value deflation will be lower due to the influence of higher-price (and lower value deflation) summer months.

Figure 15, below, shows the average annual solar value deflation (based on the 2019 system load profile) as a function of solar penetration, with solar penetration ranging from current levels of 13% up to 60% of annual CAISO electricity generation.

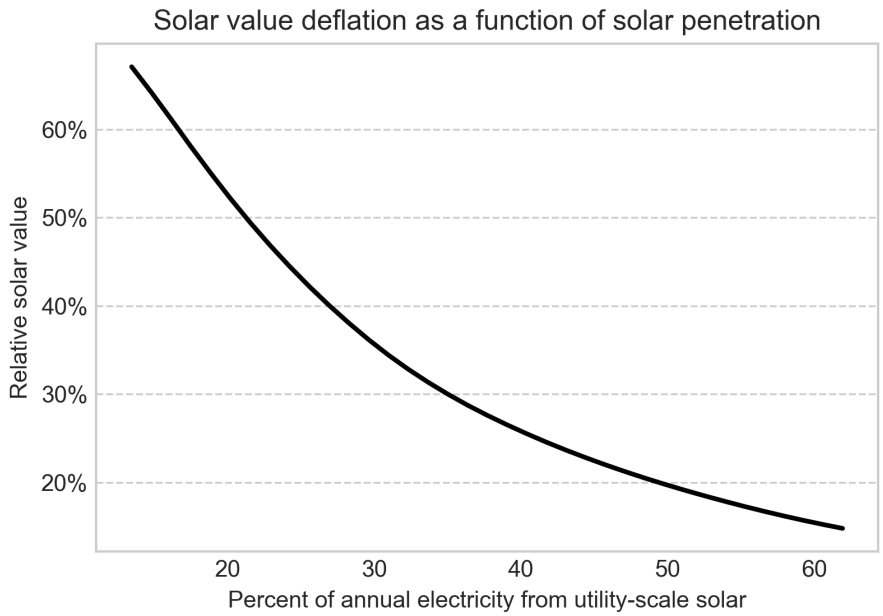

Figure 15: Modeled annual mean solar value deflation in CAISO using fixed 2019 load, inclusive of curtailment across levels of utility-scale solar penetration ranging from the 2019 value of 13% to over 60%.

The shape of the solar deflation curve is somewhat convex, reflecting the persisting solar value in summer and winter months and the maximum limit to solar value deflation in spring and fall months. We find that there will be around 48% average annual value deflation at 20% utility-scale solar penetration in CAISO, 65% value deflation at 30% penetration (similar to Sivaram and Kann's 69% estimate),[25] 74% value deflation at 40% penetration, 80% value deflation at 50% penetration, and 85% at 60% penetration.

It is worth noting the limitations of the linear statistical model employed here compared to more complex energy systems models. This model effectively tells us how much value deflation would have happened in 2019 at different levels of solar penetration. However, in the real world, both the load and resource mix will change, and that will impact the relative value of solar in ways not reflected in our model. The future energy system will also likely include more grid flexibility, with fewer non-dispatchable fossil assets (e.g., the 10% residual fossil use that we see even under high levels of solar penetration in CAISO today). Complementary technologies such as storage and long-distance transmission will likely decrease the magnitude of future value deflation and cannot be effectively simulated in these sorts of statistical models.

Modeled value deflation in CAISO only explicitly accounts for utility-scale solar. However, the impact of small-scale behind-the-meter solar is implicitly included in the model, as it impacts both the demand and the marginal electricity prices experienced historically under different levels of utility-scale solar generation. Thus the value deflation experienced at 13% utility-scale solar in CAISO is comparable to the value deflation experienced at 19% statewide solar generation from combined utility and small-scale solar. Because small-scale solar and utility-scale solar share a similar production curve, the magnitude of future value deflation should be relatively insensitive to the partitioning of future solar generation between utility-scale and small-scale.*

* This would not necessarily be the case if future small-scale solar was frequently paired with small-scale storage at a building level. That would be similar to the cases examined later where complimentary technologies reduce the magnitude of future value deflation. Additionally, the lack of curtailability of rooftop solar could potentially cause problems at high penetrations.

PART FOUR: THE RACE BETWEEN COST DECLINES AND VALUE DEFLATION

Solar in California is locked in a race between cost declines and value deflation. The extent to which solar deployment can rapidly increase in California without substantially raising consumer costs depends on both the rate of future solar cost declines and the extent to which complementary technologies reduce solar value deflation.

In order to explore possible future cost and value trajectories of solar in California, we combine the value deflation results from our statistical model with a scenario for future California electricity generation, up-to-date California solar costs, and future cost declines based on assumed learning rates and global solar deployment rates. This allows us to project future solar costs and value between 2014 and 2045.

California Senate Bill 100 (SB100), passed in 2018, requires that clean energy supply 100% of electric retail sales to end-use customers in California by 2045. The California Energy Commission (CEC) recently produced a model estimating that state-wide solar generation will increase from 19% in 2019 to 35% of total generation in 2027, 43% in 2030, 50% in 2035, 53% in 2040, and 60% in 2045.[26] We estimate annual deployment values by linearly interpolating between their provided values. Figure 16 shows projected solar generation in California (bars), as well as the statewide solar penetration (percent of generation; line) over time.

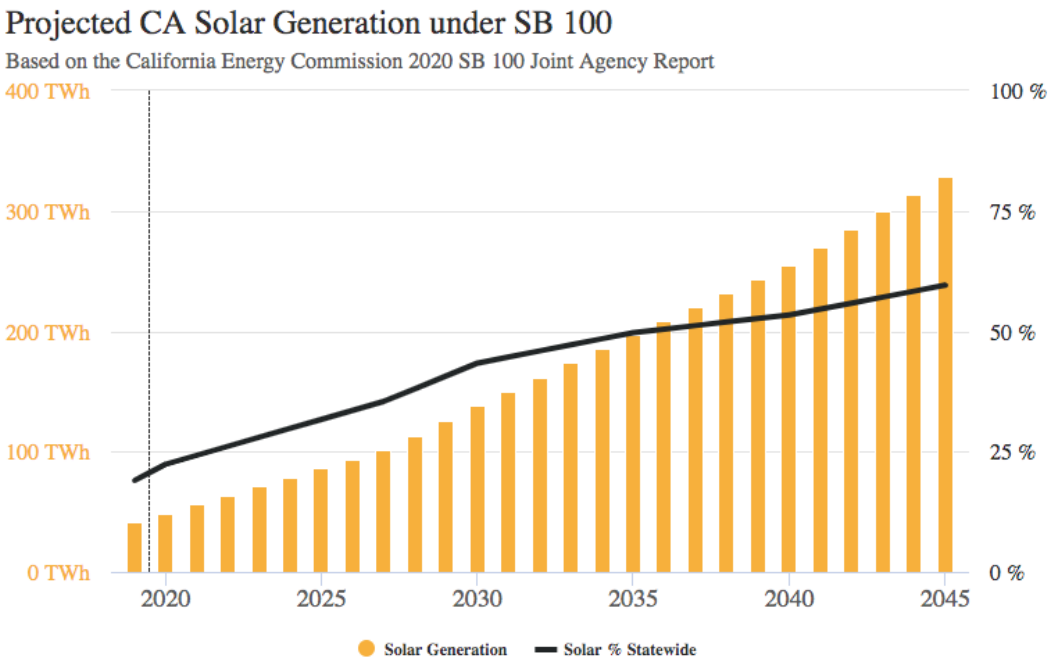

Figure 16: Historical (2019) and future solar generation (yellow bars) and penetration (percent of total California generation, black line) based on the CEC 2021 SB 100 Joint Agency Report.

These future generation projections are converted into estimated annual solar value (per MWh) using both historical CAISO data (2014-2019) and the value deflation curve in Figure 14.* To account for the difference between current (2019) state-wide solar penetration (19%) and CAISO penetration (13%) — which is due largely to small-scale behind-the-meter solar installations — future CEC statewide penetration projections are adjusted downwards by the difference between the two (6%) for the purposes of calculating value deflation.** This necessarily assumes that the future partitioning of solar between utility-scale and small-scale will not affect the resulting value deflation.

We use up-to-date California solar costs from the Utility Scale Solar Data Update produced by researchers at Lawrence Berkeley National Labs.[27] This provides both power purchase agreement (PPA) prices paid by CAISO up through 2019 (reflecting the amount actually paid to power producers) and estimated levelized cost of energy (LCOE) for CAISO solar projects (reflecting unsubsidized costs). In 2019 PPA prices were approximately 40% lower than LCOEs in CAISO, reflecting the combination of the 26% federal solar investment tax credit, state-level incentives, and equity investor risk***; we examine future solar costs in both subsidized PPA and unsubsidized LCOE cases, assuming the 40% difference between the two stays constant to simplify our analysis.

Future solar costs are calculated based on future global deployment assumptions and learning rates. Following Naam 2020[28], we use the 2019 IEA WEO Sustainable Development Scenario's 16% annual growth rate for global solar installation for the years 2020-2040 (extended through 2045).[29] This results in approximately five doublings of global solar capacity relative to current levels by the year 2045. We examine two different potential future learning rates: a conservative learning rate of 18% per doubling of installed capacity based on data from the 1975-2015 period,[30] and a learning rate of 30% per doubling of installed capacity based on the more recent 2010-2020 period.****[31]

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* As discussed earlier, solar values shown here only reflect the system-wide marginal electricity price rather than node-specific locational prices. Depending on local loss and congestion pricing solar in some locations may be more or less valuable.

** Note that the value deflation present in our model at 13% solar penetration in CAISO effectively already includes non-utility-scale deployments, which affect both the prices and total load.

*** Some of the rapid decline in PPA costs relative to LCOE over the past decade is due to a large decrease in solar project internal rates of return, effectively representing a solar subsidy by the investors, and many of the lowest price PPAs will get canceled if investors don't buy into the low returns. It is unclear the extent to which this investor subsidy can continue going forward, though it may be replaced by additional effective subsidies under SB100's emissions caps.

**** While the recent price declines in solar have actually exceeded 30% per doubling, it is unclear how long these can persist. Although module and inverter capex may continue to see large cost reductions, it is unclear that soft costs associated with utility scale solar will see similar continued declines.

Figure 17, below, shows both the historical and future cost (based on subsidized PPA prices that include varying amounts of investor risk) and value of solar in CAISO between 2014 and 2045.* Note that the value here reflects the average value of all solar generation in the grid, while the cost reflects the marginal cost of new solar deployment. Solar deployments at a given marginal cost should account for likely future value deflation; at the same time, the scenario shown here does not allow for complementary technologies to potentially reduce future solar value deflation.

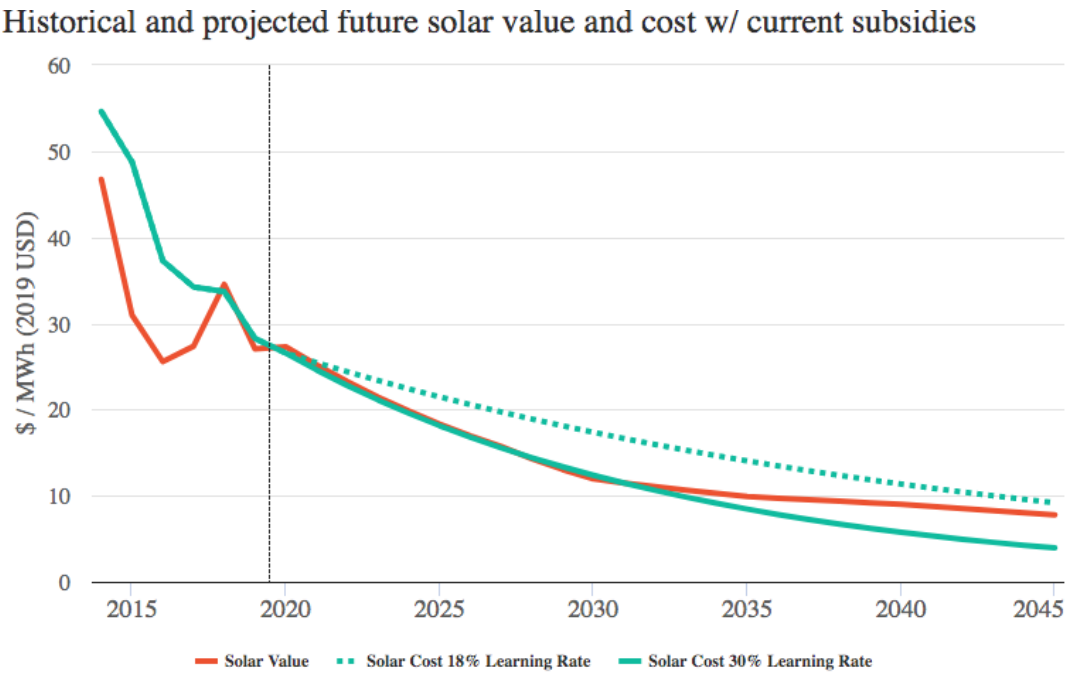

Figure 17: Historical and future solar value (red; based on the value deflation model) and PPA costs (teal) using both 18% and 30% learning rates to extrapolate future costs based on current (2019) values.

Between 2014 and 2017 the cost of solar (as reflected by PPAs) was generally higher than the value (e.g. wholesale price) of solar in CAISO. This changed in 2018 and 2019, with the value of solar closely matching solar costs. Our model expects values and costs to remain quite similar through 2022 or so, after which a gap opens up and solar value is expected to be significantly below solar costs if learning rates do not continue at the 30% rate that characterized the 2010-2020 period. This gap occurs because the deployment of solar accelerates significantly in the

*Note that solar value shown here is an incomplete representation of the amount actually paid to solar producers in California, as it excludes location-specific congestion or loss pricing (which may be positive or negative depending on the location of the resource); however, these tend to be relatively small compared to the marginal energy price.

deployment projections we use, with solar penetration more than doubling by 2030, and driving rapid value deflation. However, we should avoid overinterpreting the gap between cost and value as determinative of future solar installations; decisions about whether to build additional solar depend on the cost of solar (and its value) relative to other new resources, not necessarily simply the ratio of solar value to solar cost.

Using current CAISO PPA costs as the basis for future solar costs implicitly assumes the continuation of subsidies both from the government and investors. The model extrapolates 2019 costs forward in time using different assumed learning rates, and this effectively extends the 40% cost difference between solar PPAs and LCOEs through 2045. In order to assess the impact of f uture learning rates in the absence of subsidies, we provide an additional analysis looking at the future unsubsidized solar costs, as shown in Figure 18, below.

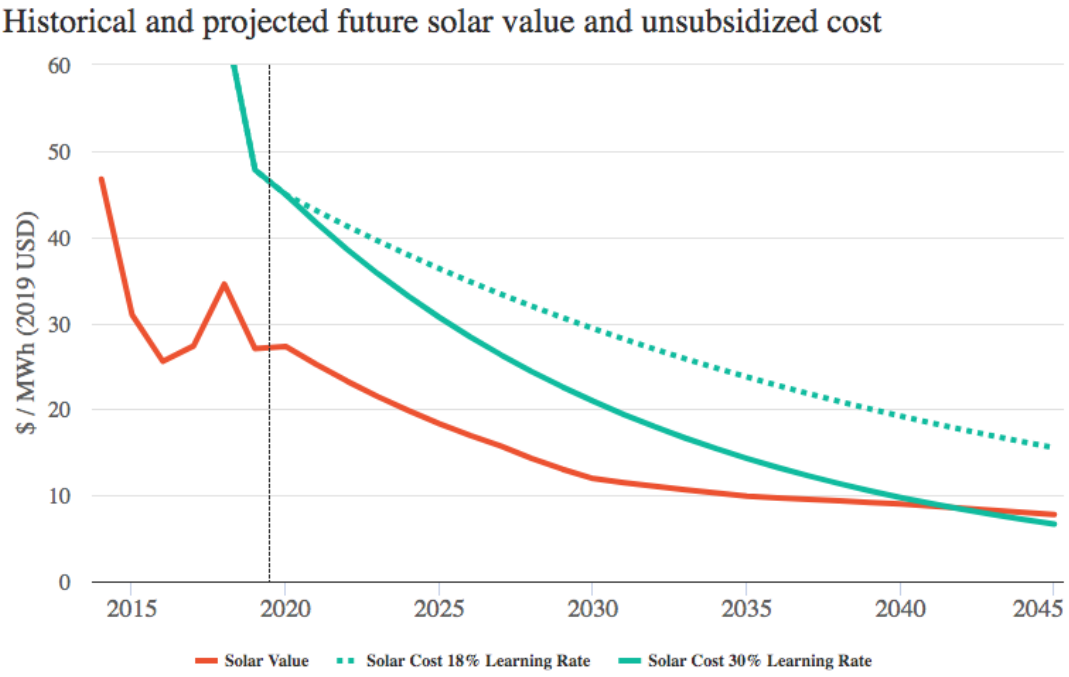

Figure 18: Historical and future solar value (red; based on the value deflation model) and LCOE costs (teal) using both 18% and 30% learning rates to extrapolate future costs based on current (2019) values.

The availability of solar subsidies makes a large difference to both the current cost-effectiveness of solar and its ability to keep up with current value deflation. While the assumption of a perpetual 40% discount on PPAs relative to LCOE may be ambitious, assuming an end to future subsidies would be equally problematic. While technology-specific subsidies may be phased out as solar deployment grows, other technologically-neutral deployment policies such as carbon

pricing or clean energy standards would increase the cost of natural gas and effectively raise the relative value of solar. California's carbon prices will also likely increase as the state's decarbonization targets become more challenging to achieve.

Because solar costs are expected to decline so rapidly in the future, a persistence of subsidies like the ITC that lower costs by a fixed percent would not necessarily incur much higher annual costs in the future, even as solar exceeds 60% of California's state-wide generation. Figure 19, below, shows the estimated cost of continued solar subsidies across the two different learning rate scenarios analyzed. This is calculated by multiplying the solar generation in each year by the difference between extrapolated future LCOE and PPA-based costs.

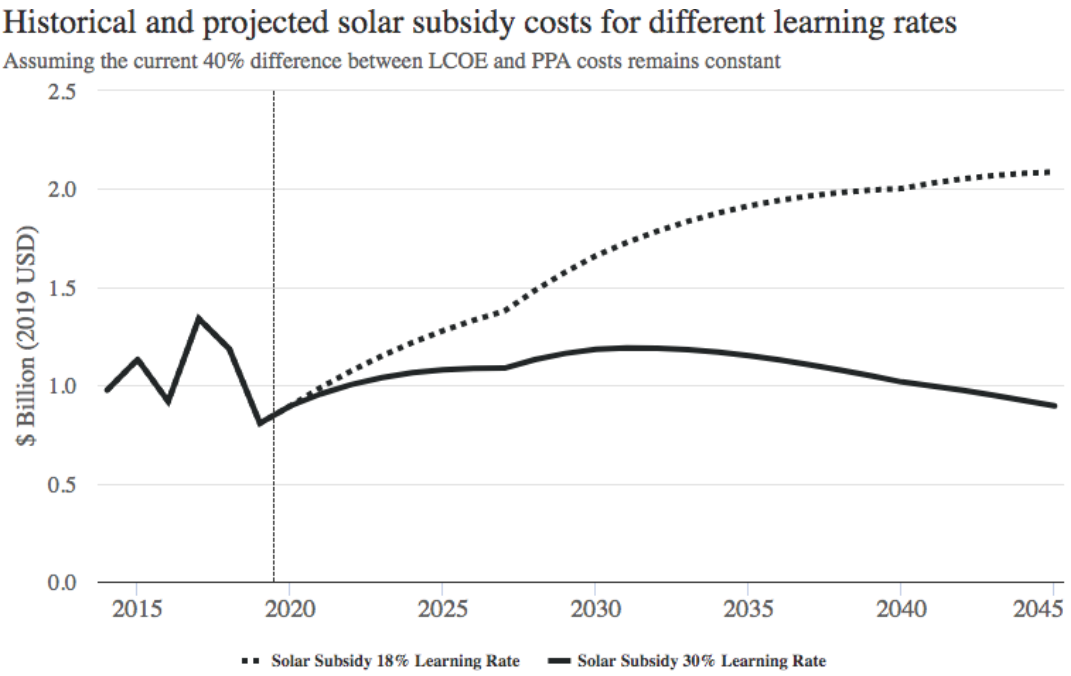

Figure 19: Estimated annual cost (in billion 2019 USD) for historical and future solar subsidies in California, based on the generation in each year and the difference between PPA and LCOE-based cost estimates. Note that there is a constant 40% reduction in PPA costs vs. LCOE costs for future years, reflecting the difference in 2019.

At a 30% learning rate, total solar subsidy costs would plateau around current values (~$1 billion) through 2045, even as solar deployment more than triples from current levels. At an 18% learning rate, solar subsidy costs would roughly double by the year 2045 under the CEC scenario where solar reaches 60% of total state-wide generation.

These subsidy values can be converted into an effective price per ton of CO2-eq reduced if we assume that additional solar generation (excluding curtailment) displaces natural gas. We estimate that 2019 subsidies of $19.5 per MWh solar (e.g., the difference between LCOE and PPA prices) represent an effective carbon price of $37 per ton CO2-eq.* By 2050 this subsidy is equivalent to only $12 per ton CO2-eq under the 18% learning rate case, and $5 per ton CO2-eq under the 30% learning rate case.

If the value of solar falls faster than its costs, it could hinder the rate of solar deployment and increase California energy costs; however, as our model assumes fixed 2019 grid conditions, it is quite possible that complementary technologies such as long-distance HVDC transmission and storage may help eliminate this value gap and enable rapid deployment of solar. It is clear from energy system models that complementary technologies can reduce the magnitude of value deflation.[32] At the same time, they are far from a panacea, and significant value deflation will remain even in the presence of cheap storage technologies. For example, Mills and Wiser (2015) suggest that a reduction in storage costs of 80% would reduce value deflation in California by up to 30%.[33]

In order to account for uncertainties in both future learning rates and the role of complementary technologies in reducing value deflation, we undertook a sensitivity analysis of both assumptions. In Figure 20, below, we compare the two different cost scenarios (using 18% and 30% learning rates) with four different value scenarios (examining no reduction in solar value deflation, a 15% reduction, a 30% reduction, and a 50% reduction) in order to approximate the role that complementary technologies may play. We do not, however, explicitly model these complementary technologies or account for their contribution to overall energy system costs.

*This assumes natural gas emissions of 0.52 tons CO2-eq/MWh, based on direct CO2 emissions of 0.41 tons CO2/MWh and a 2% system wide gas leakage rate using a 100-year GWP of 34.

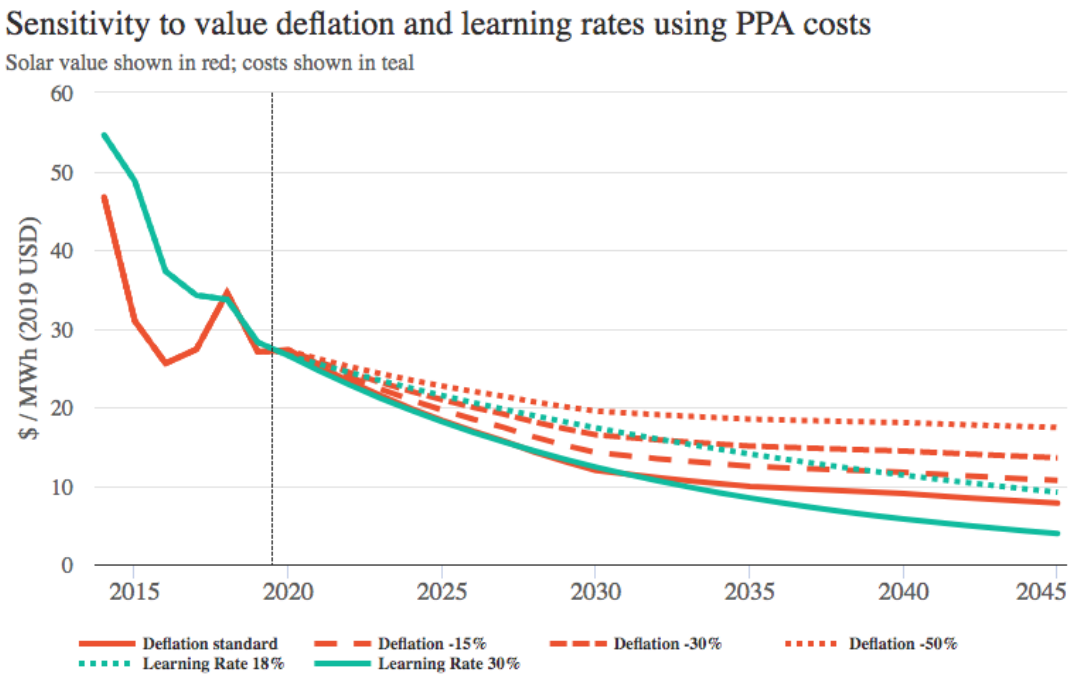

Figure 20: Historical and future solar value (red; based on the value deflation model) and subsidized PPA costs (teal) using both 18% and 30% learning rates and four value deflation scenarios (standard value deflation, 15% less, 30% less, and 50% less) to assess the potential impact of complementary technologies on solar value.

Under the current solar subsidy regime, reducing the solar value deflation by 30% would be sufficient to keep solar value at or above solar costs for the next 25 years at a lower-end (18%) learning rate. The period where the risk of costs exceeding values is highest is between 2020 and 2035, as the rapid pace of projected deployment may exceed the rate of cost reductions. It is this period where the use of complementary technologies to reduce value deflation — storage, demand shifting, and transmission expansion — will likely be most critical in a scenario where California follows the CEC's projected solar deployment under SB 100.

Figure 21, below, shows a similar sensitivity analysis for the unsubsidized LCOE case. If we examine the no-subsidy case, under a 30% learning rate solar costs are still expected to fall below solar values in the mid-2040s (and below solar values in the mid-2030s under 30% or 50% lower value deflation scenarios). However, costs will remain above values for the next two decades, reflecting the need for sustained subsidy regimes or mandates to drive high levels of solar deployment in California.

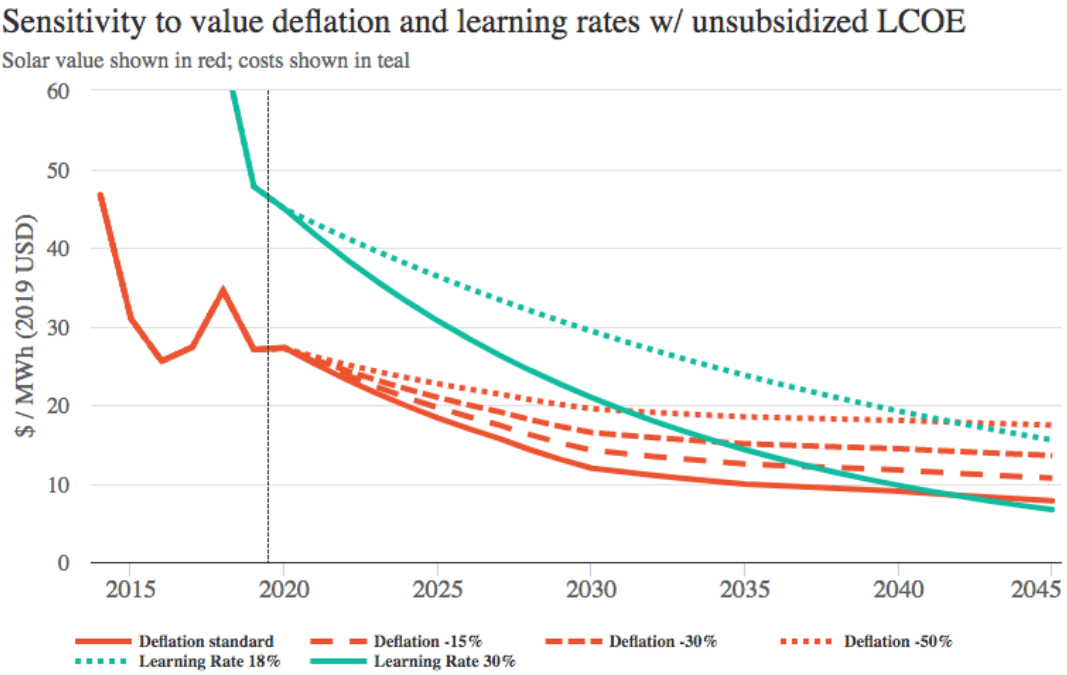

Figure 21: Historical and future solar value (red; based on the value deflation model) and unsubsidized LCOE costs (teal) using both 18% and 30% learning rates and four value deflation scenarios (standard value deflation, 15% less, 30% less, and 50% less) to assess the potential impact of complementary technologies on solar value.

Value deflation is a critical factor to take into account in assessing the future value of solar in California. We already see periods of zero (or negative) electricity prices regularly occurring in spring months with solar at 19% of statewide annual generation and 13% of CAISO utility-scale generation, and the overall value of solar has fallen by around 37% since 2014.

At the same time, value deflation is not uniform across time; even with mid-day generation maxed out, solar still provides some value during morning or afternoon periods. Similarly, even though the value of solar will fall to near-zero quickly during spring months, solar remains quite valuable during summer months even at 50%+ annual penetration due to higher demand and temporal alignment of solar generation with cooling load.

In the absence of a continued subsidy regime and the deployment of complementary technologies like storage, demand shifting, and transmission expansion, achieving the 60% solar penetration that the CEC forecasts by 2045 could incur large additional costs for consumers. There has been a significant amount of focus on complementary technologies in recent years

— with California investing heavily in utility-scale storage projects and developing a regional Energy Imbalance Market. Ensuring that solar cost declines continue to win the race against value deflation will likely require redoubling these efforts.

ENDNOTES

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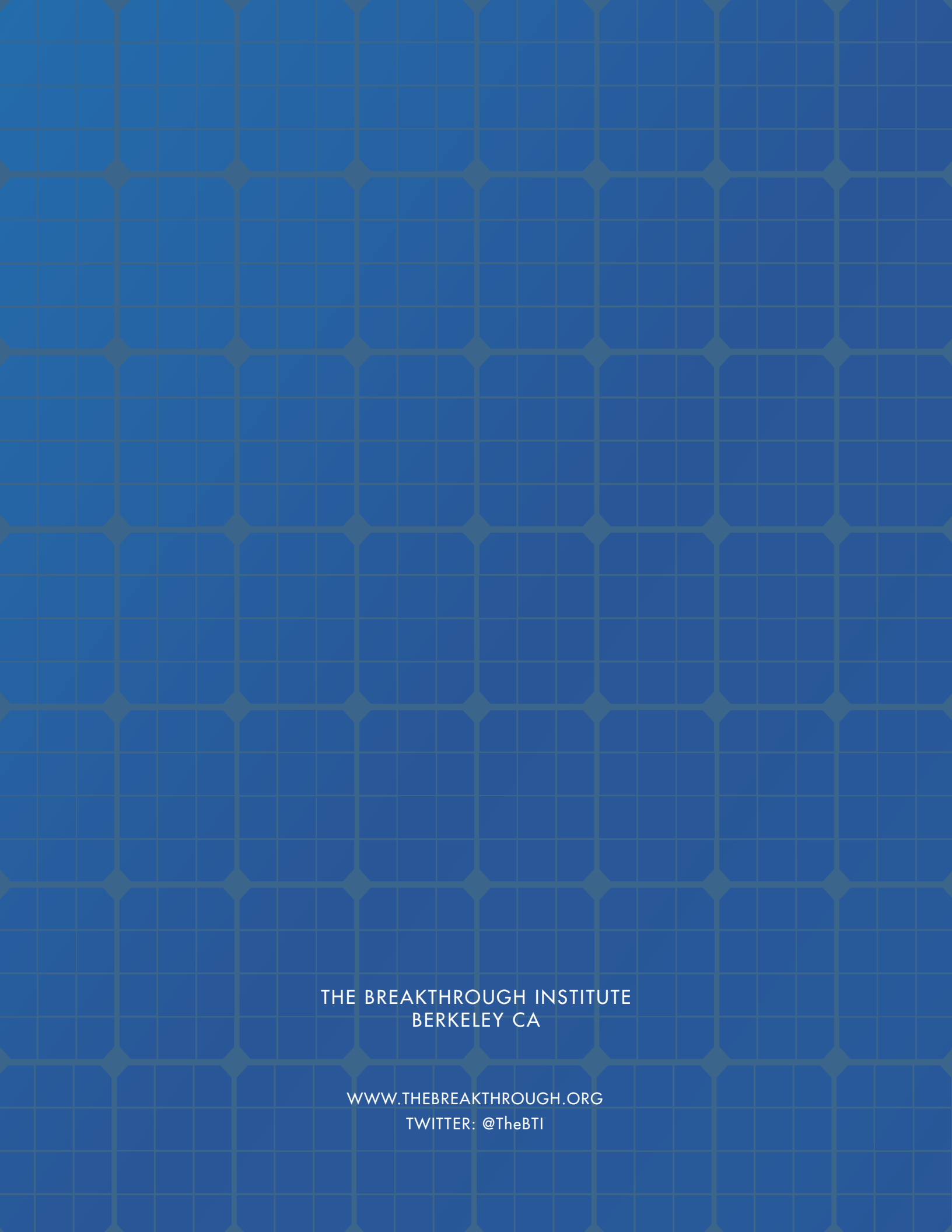

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