BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021	)))))	Rulemaking 20-11-003 (Filed November 19, 2020)

Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association

Phase 2 – Reliability for 2022-23 - Update

September 1, 2021

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I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae*, which is **Attachment RTB-1** to this testimony. As reflected in my CV, I have almost 40 years of experience on rate design and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the Commission, working on the implementation of PURPA. Since leaving the Commission in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, studies, or reports on numerous occasions before this Commission as well as state regulatory commissions in 18 other states. My CV includes a list of the formal testimony that I have sponsored before this Commission and in other state regulatory proceedings concerning electric and gas utilities.

Q: Please describe more specifically your experience on resource planning issues.

A: Since the beginning of the Commission's Integrated Resource Planning (IRP) process in 2017, I have provided technical support to solar parties in developing their position in the Commission's IRP-related proceedings. I have also been active for many years, for a variety of clients, on issues concerning the qualifying capacity (QC) of renewable resources in the Commission's Resource Adequacy (RA) dockets.

Q: Please specify your experience and expertise on electric rate design issues.

A: Over the last 15 years, I have sponsored testimony on rate design issues concerning solar distributed generation (DG) in numerous General Rate Case (GRC) Phase 2 proceedings at this Commission involving all three of the major California investor-owned utilities (IOUs). I also represented several solar industry groups in the CPUC's major investigation from 2012-2015 into residential rate design in California.   As reflected in my CV, I have also represented commercial and industrial / electric generation customers in many Commission proceedings concerning the design of natural gas and electric rates.

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of SEIA. SEIA is the national trade association of the United States solar industry. Through advocacy and education, SEIA and its 1,000 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA's members have a strong interest in the adoption and implementation of innovative, forward-looking policies and programs that will accelerate the development of solar photovoltaic (PV) generation. The views contained in this testimony represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

Q: What is the purpose of your testimony?

A: On August 10, 2021, the assigned commissioner issued an Amended Scoping Memo and Ruling (Scoping Memo) for this Phase 2 of R. 20-11-003. As set forth in the Scoping Memo, the purpose of this phase is to examine how to obtain additional supply and demand side resources to serve extreme peak demand conditions in the summers of 2022 and 2023, in response to Governor Newsom's emergency proclamation dated July 30, 2021. The Scoping Memo sets for a number of additional supply and demand side resources and changes to current requirements that could meet Governor Newsom's emergency proclamation, and asked interested parties to submit testimony on these measures. Included in these measures are changes to Critical Peak Pricing (CPP) rates, expedited generation and energy storage procurement, and interconnection issues for new resources.[1]

This testimony presents SEIA's response to the Scoping Memo on the issues of (1) eligibility for CPP rates and (2) measures to expedite the procurement and interconnection of new renewable generation and storage resources. The second topic includes a section recommending that the Commission address immediately the issues in R. 18-07-017 that are preventing small (under 20 MW), hybrid (combining renewable generation with storage) projects from contributing to meeting the state's critical near-term capacity needs.

Q: Did SEIA present testimony in Phase 1 of this rulemaking on measures to address system reliability needs in the summer of 2021?

A: Yes. In the first phase of this case, in January 2021, I presented testimony on behalf of

[1] See Scoping Memo, at p. 4.

SEIA on a number of issues concerning CPP rates, including (1) the hours covered by CPP events, (2) the number of CPP events, and (3) a recommendation that CPP rates should be uniformly available to all electric customers, regardless of whether or not they have on-site DG and/or storage and regardless of whether the customer takes service under a default tariff or an optional rate schedule. This uniform availability of CPP rates should include all rate classes – residential, commercial, industrial, and agricultural – in which customers can respond to CPP events by reducing their electric loads.[2]

Q: What was the outcome of that testimony?

A: D. 21-03-056 made changes to the CPP event hours for PG&E and SDG&E, to become effective in Summer 2022, and, for SCE, the decision increased the maximum number of CPP events from 12 to 15 per year.[3] The order also made clear that CPP would remain the default rate for those schedules for which it is now the default.[4] However, the order mentioned in passing but did not discuss, and took no action on, SEIA's recommendations on removing the restrictions on eligibility for CPP rates.[5]

Q: Does SEIA continue to believe that expanding the eligibility for CPP rates will allow more customers to participate in this important demand response program in the summers of 2022 and 2023?

A: Yes. Given the Scoping Memo's continued interest in expanding the availability of CPP rates, I am re-submitting SEIA's prior testimony on removing the restrictions on

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[2] The SEIA testimony also commented briefly on how the possible Emergency Load Reduction Programs (ELRPs) should be integrated into the state's existing Resource Adequacy (RA) program.

[3] See D. 21-03-056, at pp. 16-17.

[4] *Ibid.*, at p. 16: "[w]e do not approve a modification to the program that will eliminate the default nature of enrollment." In this regard we note that the Commission also denied PG&E's request in Advice Letter 5861-E to remove the default status of CPP rates for PG&E's commercial customers.

[5] *Ibid.*, at pp. 13-14: "Joint Solar Parties, in their opening comments, recommended that the CPP program be expanded to allow participation by (1) all residential net energy metering customers, and (2) commercial and industrial customers on optional rates."

eligibility for CPP rates.[6] I also note that the CPP issues that I address below were also raised in the Phase 1 Staff Proposal, as indicated in the discussion below.

II. ELIGIBILITY FOR CRITICAL PEAK PRICING RATES

Q: Please explain the importance of CPP rates.

A: CPP rates are the state's principal rate-based dynamic pricing program. The CPP program allows the IOUs to charge very high rates to CPP customers during a limited peak period (typically a three-, four-, or five-hour period) on a limited number of "event days" each year, called a day in advance, when loads are expected to be very high. The high CPP rates send a very strong price signal to customers to reduce loads during the peak hours of event days. These load reductions benefit the system and all ratepayers during those targeted peak hours when reliability is most threatened and market prices are very high. The utilities provide CPP customers with day-ahead notice that a CPP event will be called on the next day. CPP rates have been the default rates for non-residential customers; customers can opt-out of CPP rates but must do so affirmatively. PG&E has labeled its CPP rates "Peak Day Pricing [PDP]" rates; PG&E also makes PDP rates available to residential customers on an optional basis through its SmartRate program (Schedule E-RSMART).

Q: How are CPP rates designed?

A: The very high CPP event-day rates collect additional revenue compared to standard on-peak rates. These added revenues are offset by rate reductions in non-event rates, such that the program as a whole is revenue neutral. As a result, CPP rates are designed to

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6 In Phase 1, several parties to this rulemaking suggested that SEIA's issues on CPP rates should be addressed in the Commission's net metering case, R. 20-08-010, because our recommendations focus on providing CPP rate options for customers who install net metered solar and storage. SEIA did submit this CPP testimony on June 16, 2021, as part of its direct testimony in R. 20-08-010. However, it is unclear whether the Commission will address these CPP issues in that docket.

have no net cost to ratepayers, and ratepayers realize a net benefit from reduced demand during the peak hours when reliability is most threatened and market prices are very high.

Q: What types of issues concerning CPP rates were listed in the Phase 1 Staff Proposal?

A: The Phase 1 Staff Proposal listed three types of issues: (1) marketing of CPP rates, (2) eligibility for and design of CPP rates, and (3) encouraging use of CPP rates by non-IOU load serving entities (LSEs). My testimony focuses on the second set of issues, although a number of the CPP eligibility and design issues have implications for the marketing and availability of CPP rates.

Q: [Staff Proposal Q3] Should SCE and SDG&E be directed to offer CPP to residential customers, as PG&E does through its SmartRate (Schedule E-RSMART) program?

A: Yes. I am not aware of any issues associated with PG&E's offering of PDP rates as a rate option for its residential customers. As residential customers become educated and gain experience with TOU rates with a 4 p.m. to 9 p.m. peak period, they may be inclined to opt into CPP rates to save money during peak events, especially if they are already responding to voluntary requests to conserve energy during heat waves through public requests from the California Independent System Operator's (CAISO) and IOUs and through campaigns such as Flex Your Power. PG&E's SmartRate residential CPP program has produced significant capacity savings.[7]

Q: [Staff Proposal Q4] Should Net Energy Metering (NEM) non-residential customers in SCE's and SDG&E's territories be allowed to participate in non-residential CPP? For example, see PG&E's CPP tariff—Peak Day Pricing—which permits this.

A: Yes. This is an inconsistency between the IOUs that should be remedied before the

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[7] See the *2019 Load Impact Evaluation for Pacific Gas & Electric Company's SmartRate™ Program* (Convergence Data Analytics, March 25, 2020), at p. 8, Figure 1. Available at http://www.calmac.org/publications/3._PGE_2019_SmartRate_Report_PUBLIC.pdf. PG&E's SmartRate program has had declining enrollment due to the growth of CCAs.

summers of 2022 and 2023. As noted in the Staff Proposal, PG&E allows non-residential NEM customers to elect PDP rates, but SCE and SDG&E do not allow their NEM customers to use CPP rates. Further, PG&E does not allow residential NEM customers to participate in its residential SmartRate program. I recommend that all NEM customers – residential and non-residential – in all three IOU service territories, should be allowed to elect CPP or PDP rates. NEM customers are among the most engaged and educated of utility customers, due to the significant investment they have made in renewable on-site generation and (in most cases) their significant experience living with TOU rates.[8] NEM customers should have the same opportunity as other customers to participate in CPP programs and to respond to CPP price signals by reducing their end use loads on extreme peak days.

Q: Will NEM customers have the same economic incentive to respond to CPP rates by reducing or shifting their loads as non-NEM customers on the same rate schedule?

A: Yes. On the margin, a solar customer sees the same price signal and has the same incentive to reduce usage during a CPP event as any other non-solar customer on the comparable rate schedule, even if the solar customer is exporting power to the grid at that time. For example, even though my own west-facing PV system often can produce more power than my home consumes during the initial hours of PG&E's summer on-peak period, I retain a strong incentive to shift any available loads out of all hours of the on-peak period. If I do not run appliances between 4 p.m. and 6 p.m., I send additional solar kWhs out to the grid, earning additional net metering credits at close to the PG&E summer on-peak rate. Then I pay the much lower off-peak rate when I run appliances in the off-peak hours of the late evening, morning, or midday. Thus, even as a solar customer, I continue to see the same TOU price signal as non-solar customers on PG&E's residential TOU rate, and have the same incentive to shift my loads to off-peak

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[8] Under the NEM 2.0 program in effect since 2016-2017, NEM customers must take service under a TOU rate. See D. 16-01-044.

periods. CPP rates simply represent a re-design of the on-peak TOU energy rates, with the highest on-peak rates more narrowly and accurately focused on the CPP event days when there is the greatest need to minimize on-peak use. The high event-day rates are offset by lower rates on non-event days, on a revenue-neutral basis.

Q: The compensation to solar customers using net energy metering (NEM) is currently the subject of R. 20-08-020. Will the availability of CPP rates to solar customers using NEM have a significant impact on the compensation to NEM customers from their solar output?

A: No. CPP rates are designed to be revenue neutral, such that the higher revenues from the very high on-peak CPP rates during event days are offset by lower on-peak rates on non-event days. In this respect NEM customers are no different than other customers – customers on CPP rates can save money by reducing their electric loads during CPP events. NEM customers should be allowed to use CPP rates so that they also can contribute to load reductions during extreme weather events, starting with the summer of 2021. Further, solar output is low and declining quickly during the CPP event hours of 4 p.m. to 9 p.m., and only a small share of solar output occurs during the 4 p.m. to 9 p.m. peak period.[9] There is no practical way for solar customers to increase their generation during CPP events – their panels will produce power based on whatever late afternoon solar insolation is available on a given day. Any suggestion that NEM customers can somehow "game" CPP rates should be dismissed.

Q: Are there benefits to the system if all solar customers are allowed to use CPP rates?

A: Yes. First, as noted above, like all customers, solar customers have the potential to

[9] Typical rooftop solar systems in California only produce 5% to 7% of their annual output during the 4 p.m. to 9 p.m. peak period in the four summer months (June – September). It is important to recognize that solar PV systems are not dispatchable, so a solar customer cannot make his solar panels produce more power on CPP event days. Solar output depends on the availability of sunshine, not on whether a CPP event has been called.

reduce or to shift some of their end-use loads out of the CPP event period. Second, there are a lot of NEM customers – about 10% of all IOU customers – so expanding the eligibility of CPP rates will add significantly to the pool of possible CPP participants. Third, because the CPP rate structure focuses very high on-peak rates on CPP event days, solar customers will have a small incentive to make certain that their systems are working properly and are on-line during all CPP event days. This incentive is modest given the low solar output from 4 p.m. to 9 p.m. More important is the consideration that, as more customers install solar-plus-storage systems, CPP rates will provide a powerful incentive for customers to discharge their stored energy to the maximum extent possible during CPP events.

Q: [Staff Proposal Q4] Should general-service, non-residential customers with qualifying distributed energy resources (DERs) be allowed to enroll in CPP in SCE and PG&E's territory?

A: Yes. All three of the IOUs presently offer C&I rates that feature reduced demand charges and higher TOU volumetric rates. These rates have been designed specifically for customers with flexible loads or DERs that allow them to reduce or shift the loads that they place on the grid. Such C&I rates include SCE's Option E rates that are broadly available to all C&I customers with demands below 500 kW, and that are available to customers with loads above 500 kW that employ load-shifting technologies. All three IOUs also have similar rates for customers who install solar (PG&E's Option R rates and SDG&E's DG-R tariff) or who install a variety of different types of DERs or load-shifting technologies (SCE's TOU-8 Option E rate). Today, only a few of these rates have a CPP option.[10] This does not make sense, particularly because these rates are designed specifically for customers who have flexible loads that they can shift out of the peak period or who install various types of DERs that, in effect, reduce or shift the loads

[10] These include SCE's TOU-GS-1 rate for small commercial customers and SDG&E's DG-R rate (which customers can pair with SDG&E's CPP commodity rate, Schedule EECC-CPP-D).

placed on the grid. These rates feature reduced demand charges precisely in order to facilitate load shifting or the use of DERs.[11] These are exactly the customers who should be able to see, and to respond to, the strong price signal of CPP rates to reduce their loads during extreme events.

For example, for SCE's medium and large light & power (L&P) rate classes, SCE currently limits the availability of CPP rates to those C&I customers who are on Option D rates that include significant generation demand charges. In contrast, SCE allows small L&P customers, such as those on TOU-GS-1 whose TOU rates do not include generation demand charges, to participate in the CPP program. Indeed, CPP rates under SCE's Option E are now the default rates for TOU-GS-1 customers. In addition, PG&E's Option R rates for E-19 and E-20 customers (soon to transition to mandatory B-19 and B-20 rates) appear to allow Option R customers to elect PDP rates, but the tariffed E-19 and E-20 PDP rates do not include volumetric ($ per kWh) PDP credits. These PG&E tariffs only include the PDP demand charge credits applicable to regular E-19 and E-20 rates; applying these credits to Option R rates would result in nonsensical negative demand charges for Option R customers.

In advance of the summer of 2022, the Commission should direct the IOUs to add a CPP

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11 For example, in accepting the settlement in SCE's last GRC Phase 2 decision that implemented option E rates, the Commission observed:

> *The MLP settlement also creates an optional rate – Option E – that may benefit certain customer groups that would not otherwise respond well to the peak demand charge-heavy rate design of Option D. The Option E rate does not eliminate non-coincident demand charges, but it reduces them to make the rates more aligned with time-dependent cost-causation, which helps to provide more actionable price signals to customers considering a purchase of distributed energy resource (DER) technology. This also helps to achieve some of the goals of the Commission's DER action plan.*

See D. 18-11-027, at pp. 31-39. Option E rates are available to all C&I customers with peak demands under 500 kW. For TOU-8 customers with demands of 500 kW or above, Option E is available to option to all of these optional C&I rates, including all of SCE's Option E rates and PG&E's Option R rates. There is no policy reason not to extend the important CPP dynamic pricing option to all of the principal rate options for C&I customers. CPP rates are simply a more focused and accurate way to design TOU rates that will send customers a strong price signal to reduce loads during periods of extreme demand.

Q: If CPP rates are added to these optional C&I rate, will the customers on these rates face the same incentive to reduce their loads during CPP events as other C&I customers?

A: Yes. They will face the same high, volumetric CPP event charge as CPP customers on default C&I rates, for all of their usage during a CPP event.

III. EXPEDITING THE PROCUREMENT AND INTERCONNECTION OF NEW RENEWABLE RESOURCES

A. Expediting Transmission Upgrades

Q: Contained in the Energy Division Staff Concept Paper are several proposals regarding opportunities to bring new battery and generation resources online by summer 2022. Please provide a brief summary of those proposals.

A: The Concept Paper contains three proposals which address utility-scale projects:

(1) Imposing penalties on Load Serving Entities (LSEs) for not bringing ordered procurement resources online in accordance with Integrated Resource Planning (IRP) Decision 19-11-016. That decision requires Tranche 1 resources to be online by August 1, 2021, Tranche 2 resources by August 1, 2022, and Tranche 3 resources by August 1, 2023;

(2) Doubling the current resource adequacy penalties for LSEs who may be short in

customers with peak demands up to 5 MW who install solar, storage, or other load-shifting technology, subject to a 250 MW cap for all TOU-8 Option E customers.

August 2022 and September 2022; and

(3) Accelerating the procurement ordered in Decision D.21-06-035 by providing incentives to bring resources online by summer 2022.

Q: Do you believe that these proposals are effective means to address Summer 2022 and 2023 reliability needs to serve the net load peak?

A: No. The proposals are two sides of the same coin – incentives and penalties for LSEs – but they do little to address many of the actual problems which are impediments to bringing projects online in a timely fashion. Project developers already are highly motivated to keep projects on schedule, as contracts with LSEs typically include guaranteed commercial operation dates and financial penalties for missing those dates.

Q: Can you describe some of those impediments?

A: Yes. First, there have been delays in transmission upgrade projects identified in the CAISO's annual Transmission Plan. That plan contains a list of previously approved transmission projects which the CAISO determined were necessary to mitigate identified reliability concerns, to interconnect new renewable generation via a location constrained resource interconnection facility project, or to enhance economic efficiencies. The Plan also states the expected in-service data for each of the listed projects. The reality is, however, that many of these in-service dates are being missed, since there are no binding deadlines associated with the timelines in the TPP. Developers are also experiencing delays in upgrade work conducted as part of the generator interconnection process. There has been a consistent pattern of delay in recent years. Importantly, the timeline for transmission upgrades is solely under the control of the regulated utility that is the transmission owner. Unless the transmission owner happens to be the offtaker (buyer) for the project, penalties or incentives to the offtaker will have no impact on the project schedule, since these delays are out of the control of both the developer and the power purchaser. It does not make sense to penalize the LSE buyer for issues that are not within their control.

Q: Can you provide some examples of these delays?

A: Yes. Numerous projects seeking interconnection with Pacific Gas & Electric (PG&E) have experienced significant delays related to deliverability upgrades identified in the CAISO cluster study dated as far back as 2013 in the Cluster 6 study group. Similarly, a number of Cluster 8 projects located in the Fresno study area are still waiting for a series of five Local Deliverability Network Upgrades (LDNU) that were originally scheduled to be in-service by Q3 2020 but have been continuously delayed due to delays in permitting by PG&E. Based on the latest communication from PG&E during an April 15, 2021 stakeholder meeting with the CAISO, these upgrades are currently scheduled to be placed in-service between 2022 and 2025.[12] As a result of these delays, Cluster 8 projects that would have been available to provide RA to meet system reliability needs in 2022 and 2023 will not be able to do so until later in the decade. PG&E has also noted that this timeline is still subject to permit approval and that the in-service date for these upgrades required for Cluster 8 projects to achieve Full Capacity Deliverability Status (FCDS) could be delayed further.

PG&E is not alone; Southern California Edison (SCE) has recently communicated to developers that additional delays are expected for required Reliability Network Upgrades associated with a series of transmission upgrade projects that originally had in-service dates in Q2 and Q3 of 2023. Upgrades that originally had a 27-month upgrade timeline are now being communicated as having a 36- to 39-month upgrade timeline, effectively pushing the in-service date out 9 to 12 months. SCE has indicated to developers that this delay is due to either (1) a lack of internal resources or (2) design standard changes that SCE is contemplating but has not yet instituted. The impact is a material delay in when

[12] See presentation available at http://www.caiso.com/Documents/PG-EPresentation-GeneratorInterconnectionTransmissionUpgrades-Apr15-2021.pdf. This information was also provided in PG&E's June 2021 STAR report.

FCDS resources are able to be placed in-service and shown by LSEs for RA compliance. As with the PG&E example, these delays are affecting the most advanced set of resources in the CAISO interconnection queues that otherwise would have been positioned to help meet system reliability needs in the next few years. This also reduces the pool of resources that are far enough advanced in development to be able to compete to meet near-term reliability needs; less competition to meet these immediate needs may raise costs for ratepayers.

Q: What are the ramifications of the delays in transmission project completion?

A: Depending on the nature of the transmission project, if the project is not timely completed then the new source of generation either cannot interconnect or cannot access the deliverability needed to provide RA net qualifying capacity (NQC). Penalizing the LSE for failing to bring the resources on line in a timely fashion does nothing to remedy this problem.

Q: Are there solutions to the problem you just identified?

A: Yes. The Commission can assume more of an oversight role during the planning and construction process for approved transmission upgrades and could order more transparency by the utilities on their progress on permitting and completing the transmission upgrades. I also fully recognize that, in some cases, the transmission owners may not be responsible for delays in obtaining state or local permits for transmission upgrades. In those cases, the Commission may be able to work with other state and local agencies to resolve permitting issues that are having a real impact on the near-term reliability of the state's energy supplies. I understand that the Commission, the California Energy Commission, the CAISO, and the Governor's Office of Business and Economic Development are forming an inter-agency task force to do this, and I support that effort.

Q: How do you envision increased oversight from the Commission helping to ensure more timely completion of transmission upgrades?

A: Greater transparency and oversight would give the Commission the opportunity to identify potential delays and missed deadlines while there is still time to take action to avoid them. With better information, the Commission would be able to provide guidance to the utilities on the allocation of internal resources to prioritize the completion of transmission upgrades necessary to bring needed new generating resources online. For example, the Commission could require the utilities to report promptly when approved transmission projects are at risk of slipping from their original schedules and identify the volume of affected projects in the interconnection queue. With an opportunity for stakeholders – including affected developers and LSEs – to comment on the impact of delays, the Commission could then provide guidance to the utilities on the allocation of resources to ensure that the in-service deadlines in D. 21-06-035 and other procurement orders are not put at risk by delays in the completion of transmission upgrades. In addition, as noted above, better information also could help the Commission to work in a timely fashion with other governmental entities to resolve permitting issues.

B. Minimum Project Sizes

Q: Can you address any other market factors which are serving as impediments to bringing capacity on line in a timely fashion?

A: Yes. Certain LSEs are placing restrictive qualifications on resource solicitations which unnecessarily limits the potential capacity that they can obtain from those solicitations.

Q: Can you give me some examples of such restrictions?

A: Yes. In its recent mid-term reliability solicitation, SCE imposed a minimum project size restriction of 100 MW (later revised to 50 MW), which excludes a great number of projects. In some cases, LSEs require the use of a form contract for bids, which has the impact of complicating the amendment of existing contracts to add batteries and/or to add nameplate capacity.

Q: What do you recommend to remedy these problems?

A: The Commission should direct the LSEs not to establish unreasonable minimum project size limitations. Generally, solicitations should be open to all projects with nameplate capacities of 20 MWs or above. Renewable projects smaller than 20 MWs should have access to a long-term standard offer contract with fixed prices through the Commission's QF program, although, as I discuss in the next section below, the Commission should take further action in R. 18-07-017 to resolve certain issues and to encourage development of small, short-lead-time renewable QFs that can provide incremental capacity. In addition, the Commission should direct the LSEs to be more flexible with respect to project type and size and to allowing existing projects to bid to add RA capacity, such as adding on-site storage.

C. Resolve Pending Issues in R. 18-07-017 for Hybrid Projects under 20 MW

Q: What are the least-cost sources of new renewable capacity for California?

A: The least-cost new renewable capacity resources available to California in the near term are hybrid solar-plus-storage resources. These resources are available at a wide range of scales, including distributed wholesale generation under 20 MW in size for which the California utilities retain a must-purchase obligation under PURPA. **Attachment RTB-2** is a recent presentation from Lawrence Berkeley National Laboratory (LBNL) of wind and solar PPA costs, including the costs of adding storage to add firm dispatchable capacity to these resources.[13] The data from the LBNL Report indicates that PPA prices for solar resources on the CAISO grid are expected to be in the range of $30 to $40 per

[13] Mark Bolinger, *Utility-Scale Wind and Solar in the U.S. - Comparative Trends in Deployment, Cost, Performance, Pricing, and Market Value* (LBNL, December 8, 2020), hereafter "LBNL Report."

MWh over the next several years,[14] with a $10 per MWh adder for 4-hour storage capacity equal to 50% of the solar nameplate capacity.[15] The LBNL analysis shows that hybridization of solar with storage in California adds substantially to the value of the resulting power product, resulting in a market value of over $60 per MWh, in excess of the $40 to $50 per MWh PPA cost.[16] Smaller renewable projects that can be interconnected at lower voltages also may provide additional value from avoiding high-voltage transmission costs that are not included in CAISO or RA market prices.[17]

I would caution that the LBNL price surveys cover solar, wind, and storage resources of all sizes. Reduced economies of scale for projects smaller than 20 MW may make these smaller projects more expensive. Further, the average term of the solar PPAs contracted under the CPUC's Renewable Portfolio Standard program is 20 years,[18] which is significantly longer than the 12-year standard-offer contract (SOC) now available to QFs under 20 MW in California.

Q: Does the fixed-price, 12-year SOC now available to QFs under 10 MW in California appear to provide a level of compensation to hybrid solar-plus-storage projects that would be "in the ballpark" to cover the costs of such projects?

A: Yes. The compensation available under the current QF SOC for a hybrid solar-plus-storage project in California is also in the range of $40 to $50 per MWh, based on a

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[14] LBNL Report, at Slide 31 (showing expected solar PPA prices from 2021-2025).

[15] *Ibid*., at Slide 34.

[16] *Ibid*., at Slide 35.

[17] The avoided transmission value can be calculated from the Commission's 2021 Avoided Cost Calculator (ACC) for distributed energy resources, as applied to a solar-plus-storage output profile. The avoided transmission costs for a solar-plus-storage project in PG&E's territory near Fresno are about $5 per MWh in 2021.

[18] From the CPUC's database *RPS Executed Projects: Public Data* (updated July 2021]. See https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-reports-and-whitepapers/rps-reports-and-data.

three-year average of recent CAISO market prices for energy and recent RA market prices for capacity.[19] Thus, there is a market opportunity for new renewable capacity from small solar-plus-storage projects that can be developed in the next two years, without a significant risk of over-payment. I caution that the relatively short 12-year term of the SOC's fixed prices is a concern for developers and a possible impediment to financing such projects.

Q: **Are there actions that the Commission can take in related proceedings to encourage the development of short-lead-time renewable QF projects that provide firm capacity to the CAISO grid?**

A: Yes. The Commission should act as soon as possible in R. 18-07-017 to resolve outstanding issues concerning the availability of fixed-price, standard-offer contracts for small (< 20 MW) solar-plus-storage or wind-plus-storage QFs that can provide significant near-term incremental capacity to the CAISO grid. The actions that the Commission should take in R. 18-07-017 include:

- Reaffirm the availability of a fixed-price SOC for QFs under 20 MW, rejecting the utilities' efforts to end this option.[20] A fixed-price, long-term contract is necessary to attract financing for new clean hybrid resources that combine generation and storage.
- Clarify that the hybrid storage resources should be charged entirely from the associated on-site renewable generation.[21]
- Change the allocation of the RA-based capacity price so that the payments for capacity are based on generation during the on-peak hours.[22]

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[19] See the most recent utility filings of QF SOC fixed prices - SDG&E Advice 3823-E, SCE Advice 4558-E, and PGE Advice 6288-E.

[20] See the Joint Utility comments in R. 18-07-017 filed February 10, 2021, at pp. 2-3 and 6-9.

[21] *Ibid.*, at pp. 11-12.

[22] *Ibid.*, at pp. 10-11.

- To encourage procurement of hybrid projects with firm storage capacity that will count toward RA requirements, extend to 20 years the term of SOCs that provide 4-hour storage capacity equal to at least 50% of the nameplate capacity of the renewable resource. To meet the state's exigent capacity needs, these 20-year contracts can be limited to projects with on-line dates in 2022 and 2023.

These issues clearly are within the recently-amended scope of R. 18-07-017.[23] Further, these recommendations respond directly to the state's immediate and pressing need for new clean capacity resources.

Q: The utilities are certain to raise concerns that these recommendations will lead to a "gold rush" of over-priced QFs. Please respond to this argument, in advance.

A: As discussed above, the pricing for these new hybrid renewable capacity resources under the current SOCs approved in D. 20-05-006 is not out of line with the reported costs of such resources, and is likely to be below the value of these resources. In essence, California would bring on-line new, long-term, renewable capacity resources at a price equal to recent short-term CAISO energy and RA capacity prices, at a time when the state has a critical need for incremental capacity resources to avoid blackouts and for clean resources to reduce GHG emissions. That does not sound like a bad deal to me. Further, the size of these new QFs is limited to no more than 20 MW of renewable nameplate capacity each, so the contribution of 10 or 20 of these small projects to the state's capacity needs will be modest but helpful. Finally, the Commission retains the ability to change prospectively the term of the QF SOC, and possibly, pursuant to the Federal Energy Regulatory Commission's recent Order No. 872, to end the fixed-price option, should it have concerns about over-subscription at any point in the future.

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[23] See R. 18-07-017, *Amended Scoping Memo and Ruling of the Assigned Commissioner* (January 11, 2021), at p. 5.

Q: Does this conclude your testimony in this case?

A: Yes, it does.

VERIFICATION

I, R. Thomas Beach, am authorized to make this verification on behalf of the Solar Energy Industries Association. I declare under penalty of perjury that the statements in the foregoing Testimony are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true.

Executed on September 1, 2021, at Berkley, California.

_________*/s/*_______________

R. Thomas Beach

Attachment RTB-1

CV of R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

   - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

   - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
   b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

   - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

   - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

   - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

   - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

   - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

   - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)

    - *Gas transportation rates for electric generators, gas storage and balancing issues*

89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)

    - *Rate design for intrastate backbone gas transportation rates*

90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)

    - *Electric rate design for commercial electric vehicle charging*

91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)

    - *Avoided cost issues for distributed energy resources*

92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)

    - *Electric rate design for commercial electric vehicle charging*

93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)

    - *Electric rate design issues for solar and storage customers*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

   - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
   http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

2. Direct Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018; Docket E-100 Sub 158; June 21, 2019)

    - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

    - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).

    - *Resource value of solar resources in Oregon*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
   https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

    - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

    - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

    - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

Lawrence Berkeley National Laboratory
Utility-Scale Wind and Solar in the U.S. - Comparative Trends in Deployment, Cost, Performance, Pricing, and Market Value
(December 2020)

Utility-Scale Wind and Solar in the U.S.

Comparative Trends in
Deployment, Cost, Performance, Pricing, and Market Value

Mark Bolinger
Electricity Markets and Policy Department
Lawrence Berkeley National Laboratory

December 8, 2020

This research was supported by funding from the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office (WETO) and Solar Energy Technologies Office (SETO)

Much of the data and analysis presented in these slides comes from LBNL's annual utility-scale wind and solar data and tracking reports

Wind Technologies Market Report:

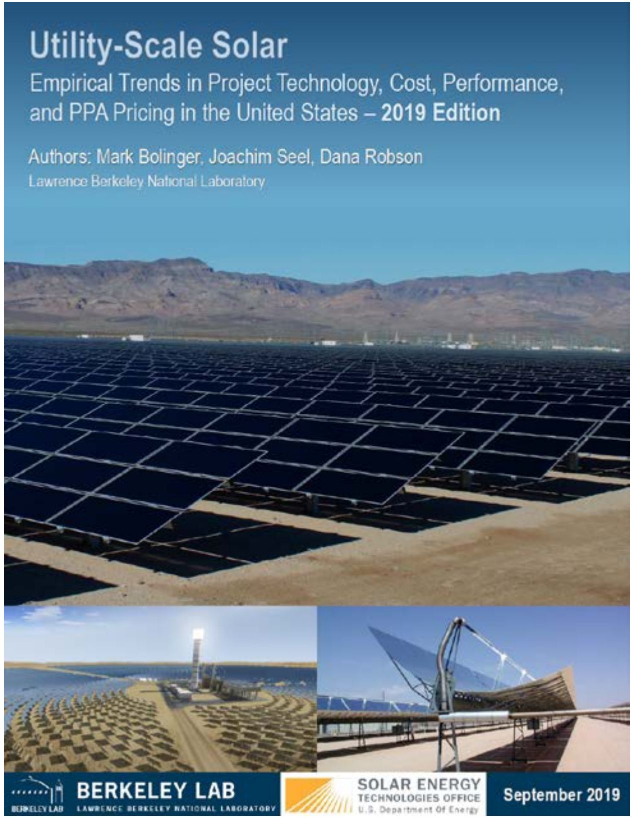
- Now in its 14th year
- **106 GW** of wind in 2019 versus **11.5 GW** in 2006

Utility-Scale Solar:

- Now in its 8th year
- **29 GW** of utility-scale (>5 MW_{AC}) PV in 2019 versus **1.7 GW** in 2012

Both are shifting towards "data products" rather than narrative reports

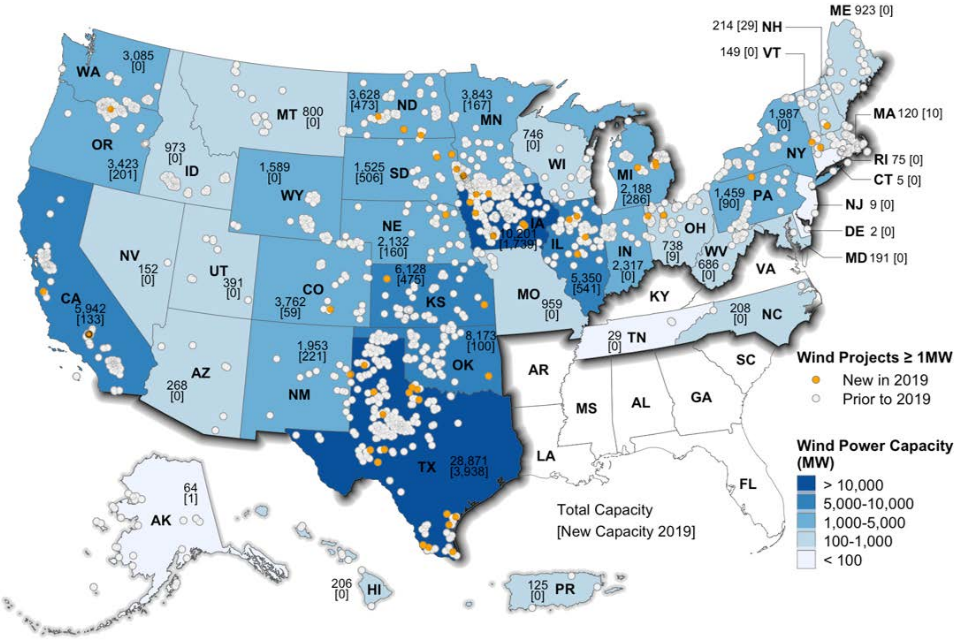
windreport.lbl.gov



utilityscalesolar.lbl.gov

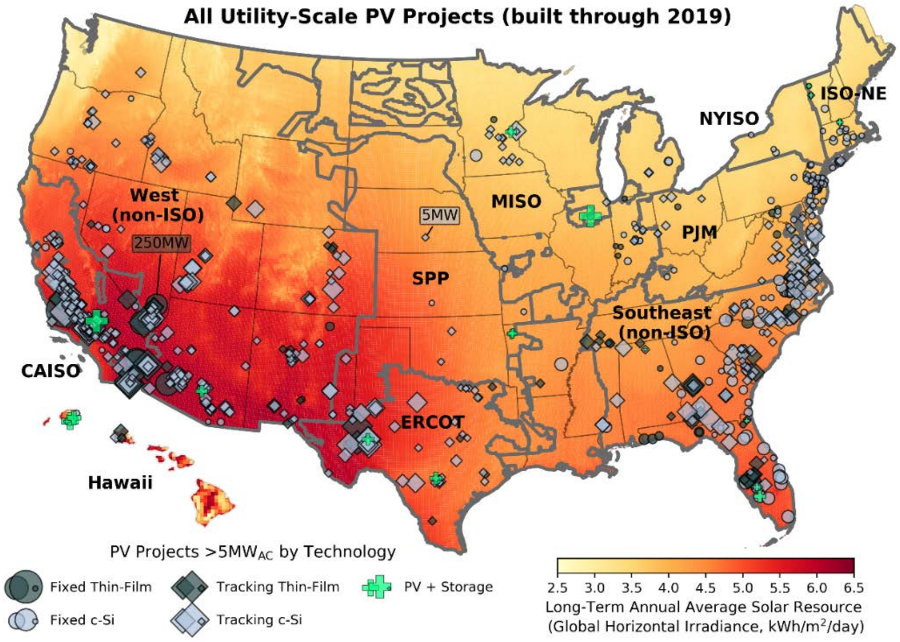
Wind deployment is concentrated in US interior; utility-scale solar historically in California and Southwest, but spreading

Wind: 106 GW at end of 2019



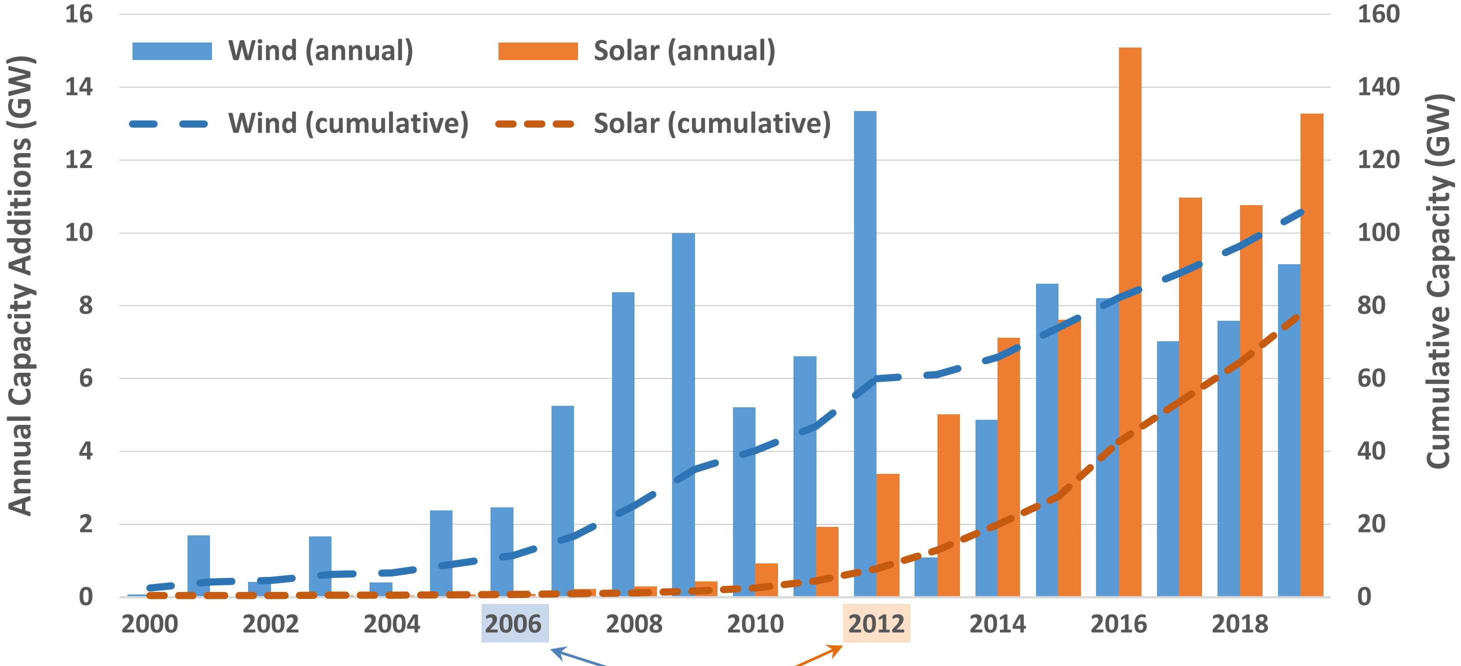
Wind map includes only projects that use wind turbines >100 kW

Solar: 29 GW_{AC} at end of 2019



Solar map includes only "utility-scale" PV projects, which we define as ground-mounted projects > 5 MW_{AC}

Annual and cumulative deployment history suggests that solar is 4-5 years behind wind (but not for long?)

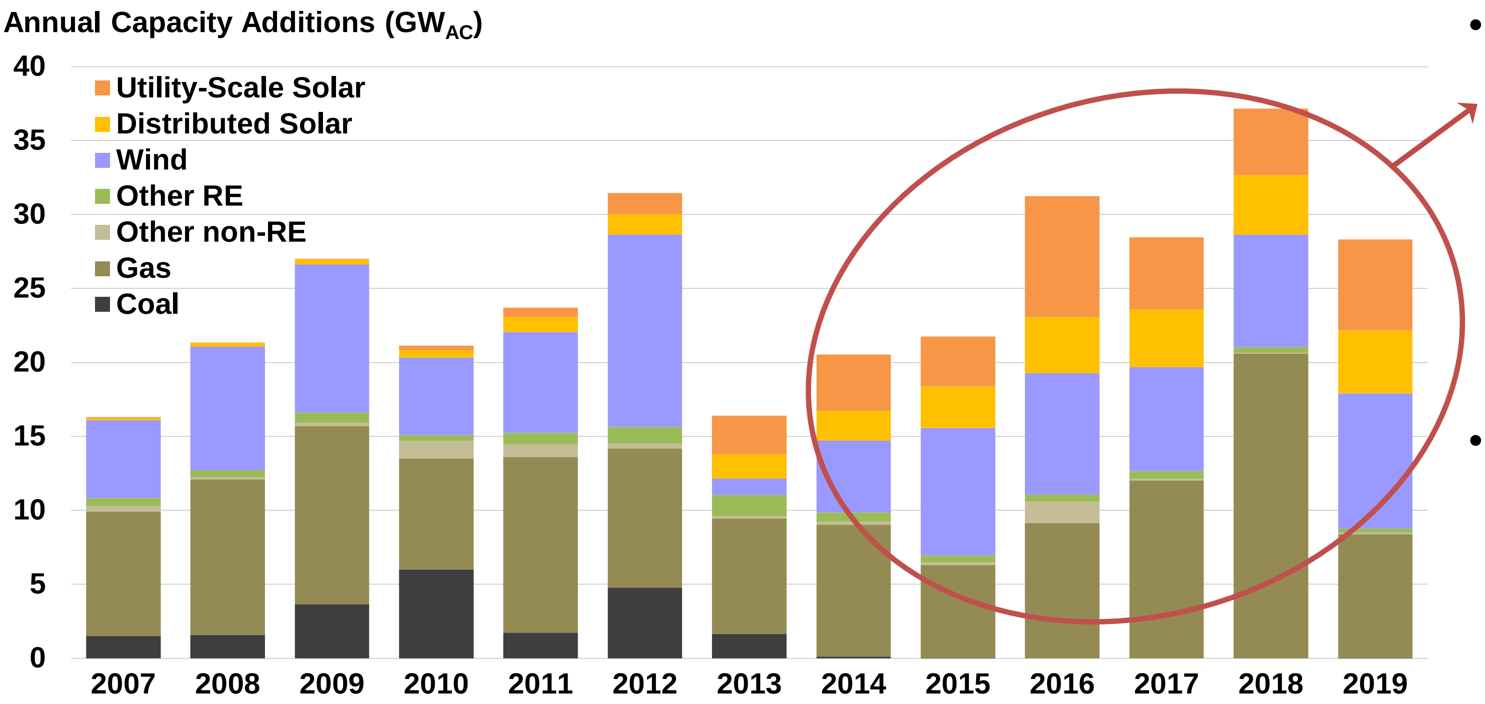


LBNL's market tracking reports for utility-scale wind and solar began in 2006 and 2012, respectively

- Both technologies have been around since the 1980s, but only started to take off in the 2000s
- Deployment spikes in 2012 (wind) and 2016 (solar) were driven by impending Production Tax Credit (PTC) and Investment Tax Credit (ITC) expirations
  - ➢ Both credits were eventually extended

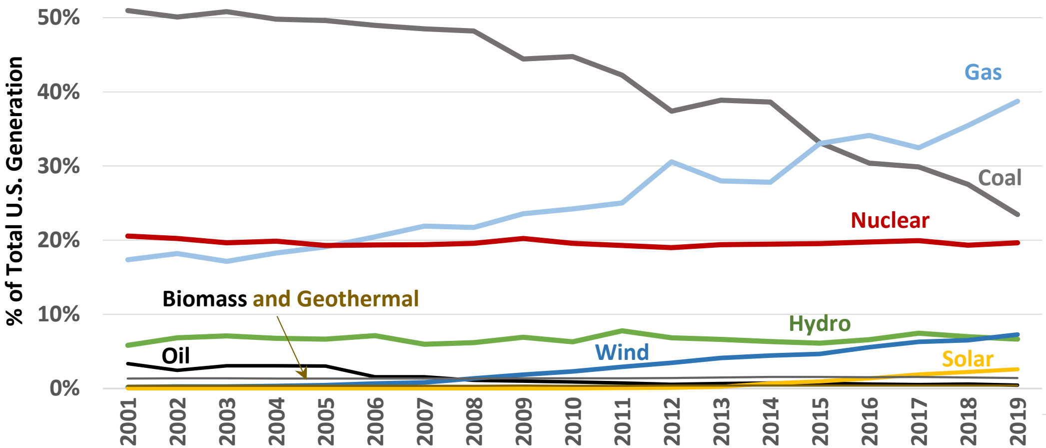
Note: The solar numbers in the graph include all sectors: residential, commercial, and utility-scale.

Over the past six years, natural gas, wind, and solar have accounted for 97% of all new capacity added to the U.S. grid



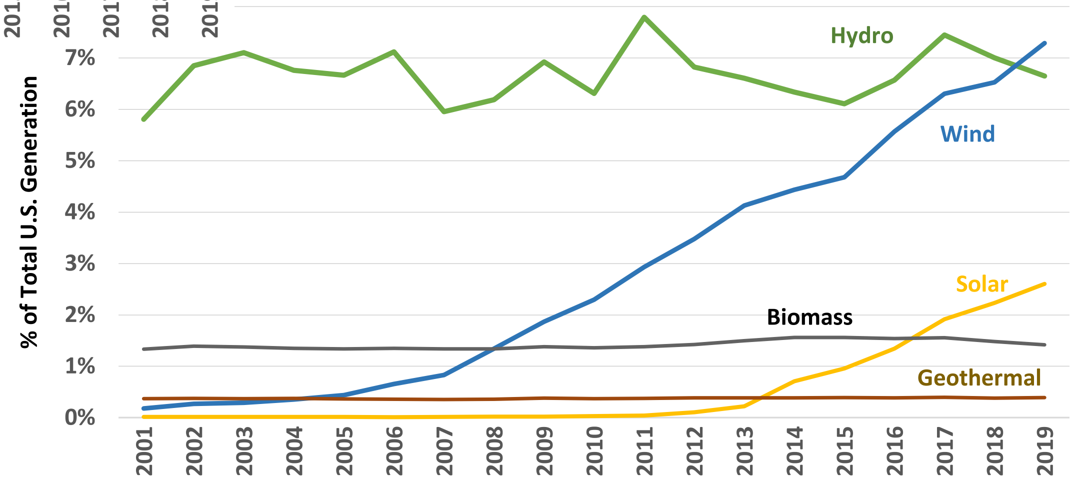
- In aggregate from 2014-2019, wind (27%) and solar (31%) contributed 58% of all new generating capacity added to the U.S. grid (with gas at 39%)
- Wind has been a consistent, significant contributor all the way back to 2007, but solar not until 2013

Yet wind and solar combined have only ~10% market share nationally (expressed as a % of total U.S. generation)



- Top graph focuses on all resources
- Gas has surpassed coal (mirror images)
- Wind and solar's share is growing, but still small
- Everything else is stagnant or declining

- Bottom graph focuses on just the renewable sources of electricity
- Only wind and solar are growing; wind surpassed hydro in 2019
- Solar is now well ahead of biomass and geothermal



Though some individual states are doing much better than 10%

WIND	2019 wind generation as a % of in-state:	
	Electric Sales	Generation
Kansas	53.5%	41.4%
Iowa	53.1%	41.9%
North Dakota	51.1%	26.8%
Oklahoma	45.3%	34.6%
New Mexico	27.4%	19.4%
Nebraska	24.7%	19.9%
Wyoming	24.1%	9.8%
South Dakota	23.8%	23.9%
Texas	20.6%	17.5%
Maine	20.4%	23.6%
Colorado	19.4%	19.2%
Minnesota	17.0%	19.0%
Montana	15.4%	8.5%
Oregon	15.0%	11.5%
Idaho	11.2%	16.1%
Illinois	10.1%	7.6%
Washington	8.6%	7.3%
Vermont	7.1%	16.4%
Indiana	6.4%	6.0%
Hawaii	6.3%	5.4%
TOTAL US	8.0%	7.2%

SOLAR	2019 solar generation as a % of in-state:	
	Electric Sales	Generation
California	17.7%	19.9%
Nevada	14.8%	13.7%
Hawaii	14.7%	12.6%
Arizona	9.9%	6.6%
Utah	8.5%	6.6%
Massachusetts	6.6%	13.7%
New Mexico	6.6%	4.7%
Vermont	6.1%	14.0%
North Carolina	5.6%	5.7%
New Jersey	4.7%	4.7%
Rhode Island	3.4%	3.2%
Colorado	3.3%	3.2%
Connecticut	2.8%	1.9%
Idaho	2.5%	3.6%
Minnesota	2.5%	2.8%
Maryland	2.4%	3.6%
Florida	1.9%	1.9%
Oregon	1.9%	1.5%
New York	1.7%	1.9%
Georgia	1.7%	1.9%
TOTAL US	2.9%	2.6%

Numbers include utility-scale and distributed solar

WIND & SOLAR	2019 wind & solar generation as a % of in-state:	
	Electric Sales	Generation
Kansas	53.7%	41.5%
Iowa	53.4%	42.1%
North Dakota	51.1%	26.8%
Oklahoma	45.4%	34.7%
New Mexico	34.1%	24.0%
Wyoming	25.3%	10.2%
Nebraska	24.9%	20.0%
South Dakota	23.8%	23.9%
California	23.7%	26.7%
Colorado	22.7%	22.5%
Texas	21.9%	18.6%
Maine	21.1%	24.5%
Hawaii	21.0%	18.0%
Minnesota	19.5%	21.8%
Oregon	16.9%	12.9%
Montana	15.8%	8.7%
Nevada	15.7%	14.5%
Idaho	13.7%	19.7%
Vermont	13.2%	30.5%
Utah	11.1%	8.6%
TOTAL US	10.9%	9.8%

Solar portion includes utility-scale and distributed

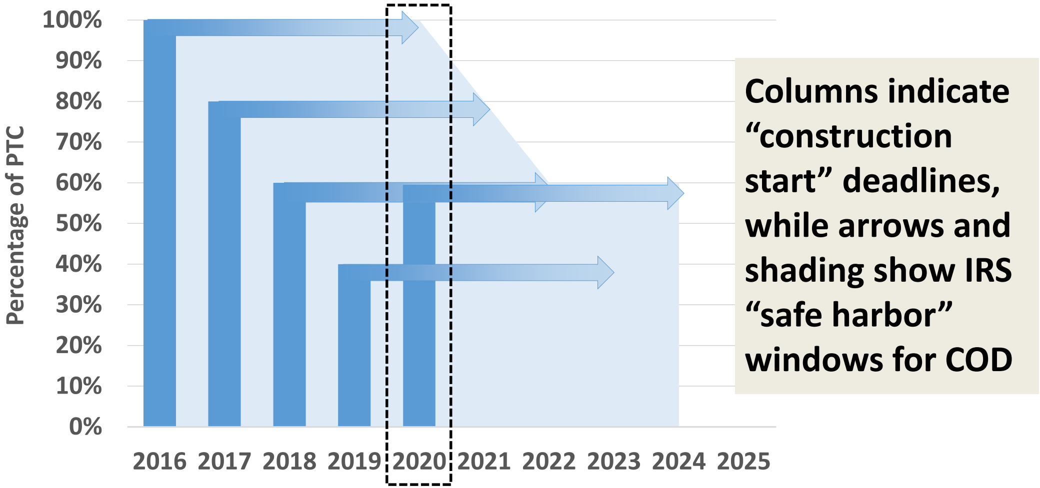
- "Top 20" states in terms of penetration of wind, solar, and both
- States ranked by their wind and solar generation as a % of total electric sales
- Wind tends to dominate the combined penetration, but solar tips the scales in some cases

Diverse drivers: policy still matters, but progressively moving towards economic competitiveness

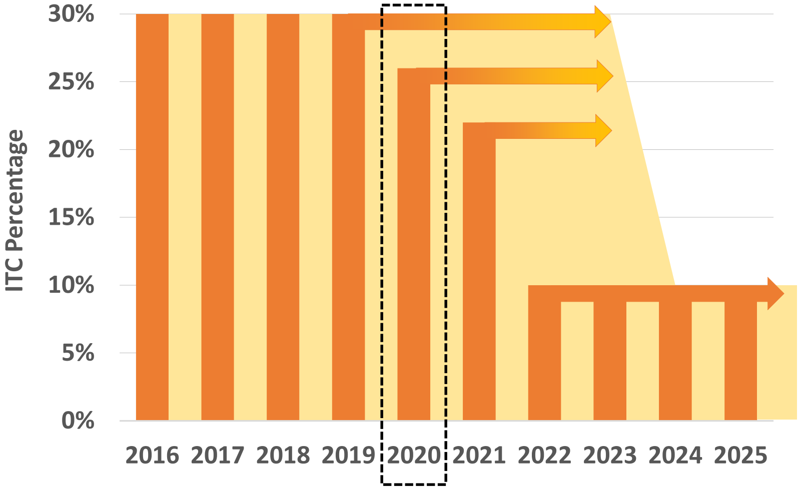
FEDERAL TAX POLICY	STATE ENERGY POLICY	ECONOMIC COMPETITIVENESS
Production Tax Credit (for wind)	Renewables Portfolio Standards (RPS)	Utility RFPs
Investment Tax Credit (for solar)	State Tax Incentives	Corporate Procurement
Accelerated Depreciation	Carbon Policy	PURPA Contracts
		Merchant Plants

Federal tax credits have been major drivers of wind and solar deployment—*but are being phased out (under current law)*

Production Tax Credit (PTC)



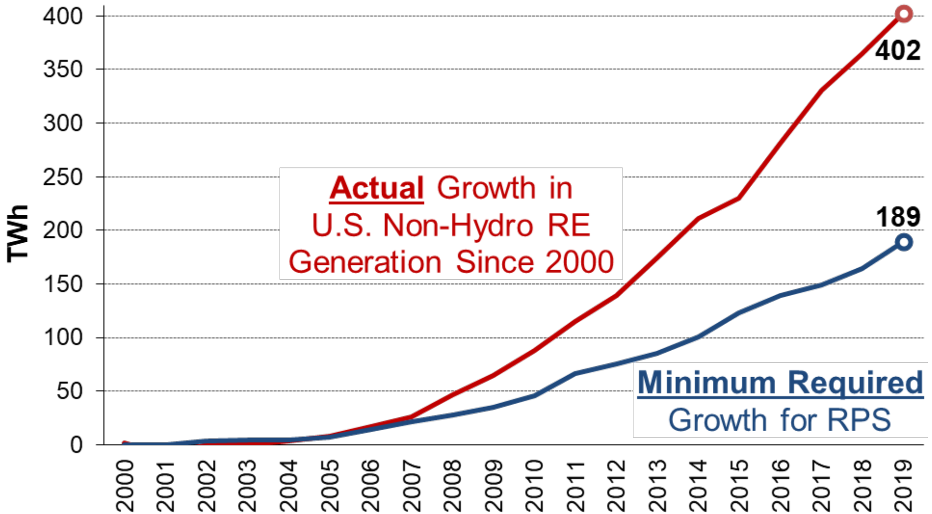
Investment Tax Credit (ITC)



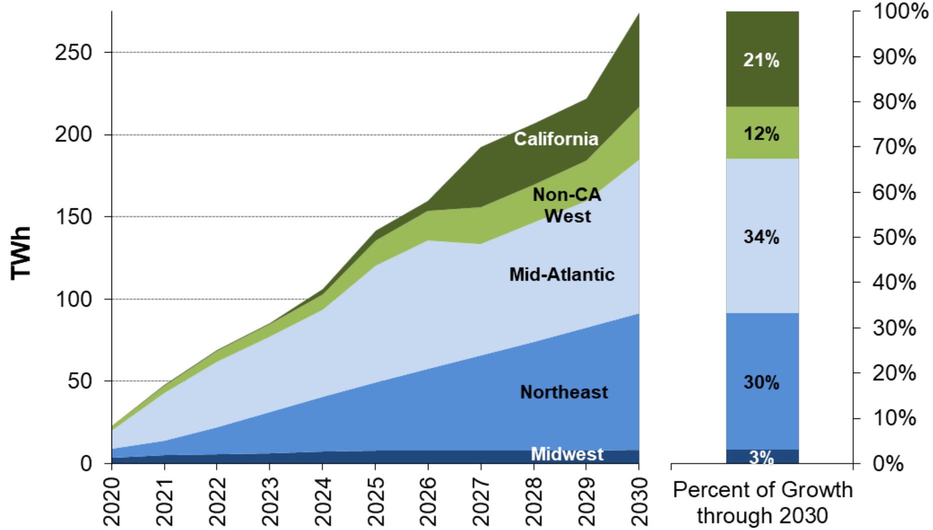
- Wind's PTC is based on production (stands at $25/MWh in 2020, and increases with inflation each year over a project's first decade), while solar's ITC is based on investment (e.g., equal to 30% of cost)
- **Different phase-down patterns:** Solar keeps its full credit longer than wind does (2023 vs. 2020), and retains the 10% ITC indefinitely (while post-2024 wind projects will not get any PTC)

Deployment has been outpacing state renewable portfolio standard (RPS) goals, but a number of states have recently increased their targets

Past Renewable Energy Growth



Future RPS Demand Relative to Supply



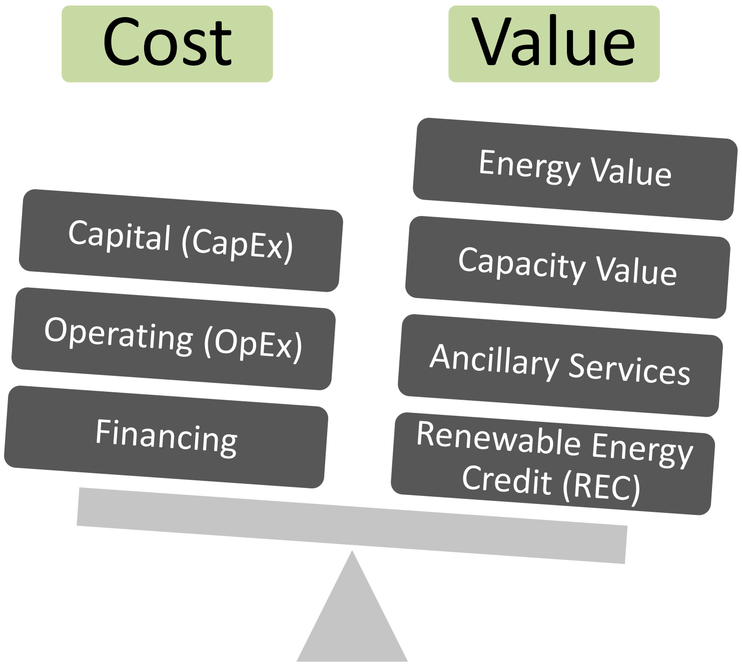
States that have significantly increased RPS (or CES) policies in 2019-2020:

DC, MD, ME, NM, NV, VA, WA

Economic competitiveness: weighing cost and value

All three **costs** shown in the figure (CapEx, OpEx, and financing), along with capacity factor and useful life, factor into LCOE and PPA prices

- **I'll cover all of these, for both wind and solar**

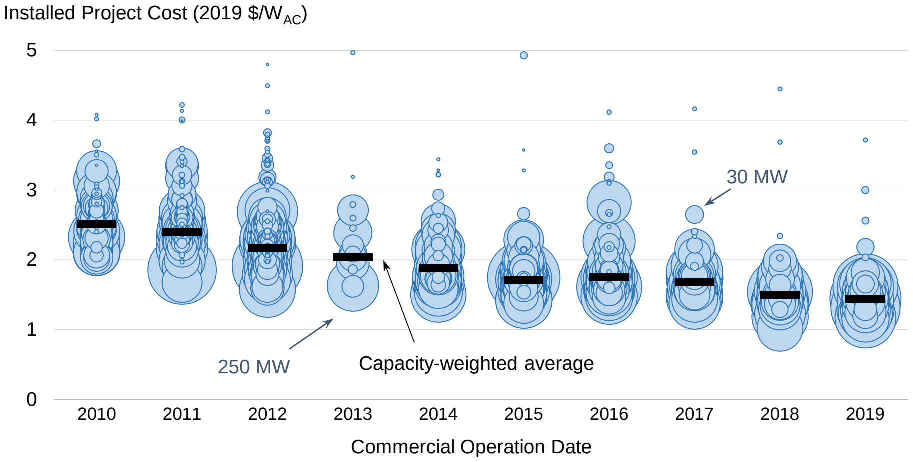


Value includes energy and capacity value in wholesale markets, as well as any additional value derived from selling ancillary services and/or renewable energy credits (RECs)

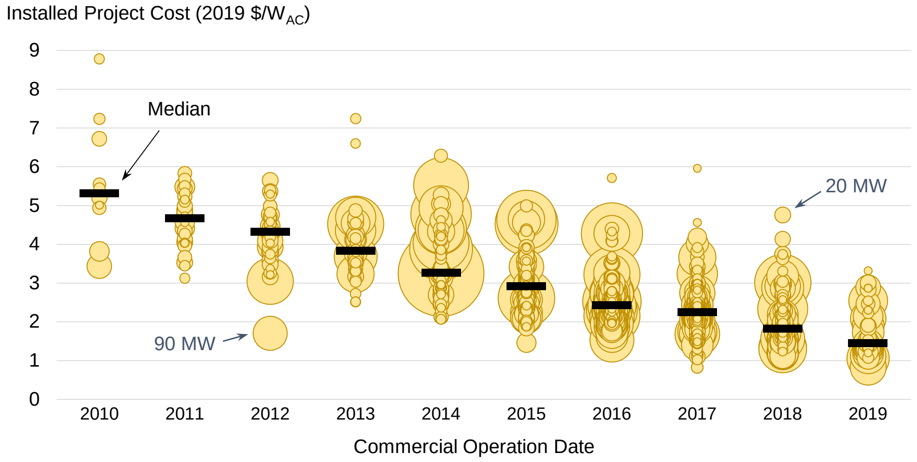
- **I'll cover energy and capacity value for both wind and solar**…but will ignore ancillary services (which provide minimal value) and RECs (which are state- or policy-specific)

Since 2010, average installed costs have fallen by 40% (wind) and 70% (solar)

Wind Installed Costs



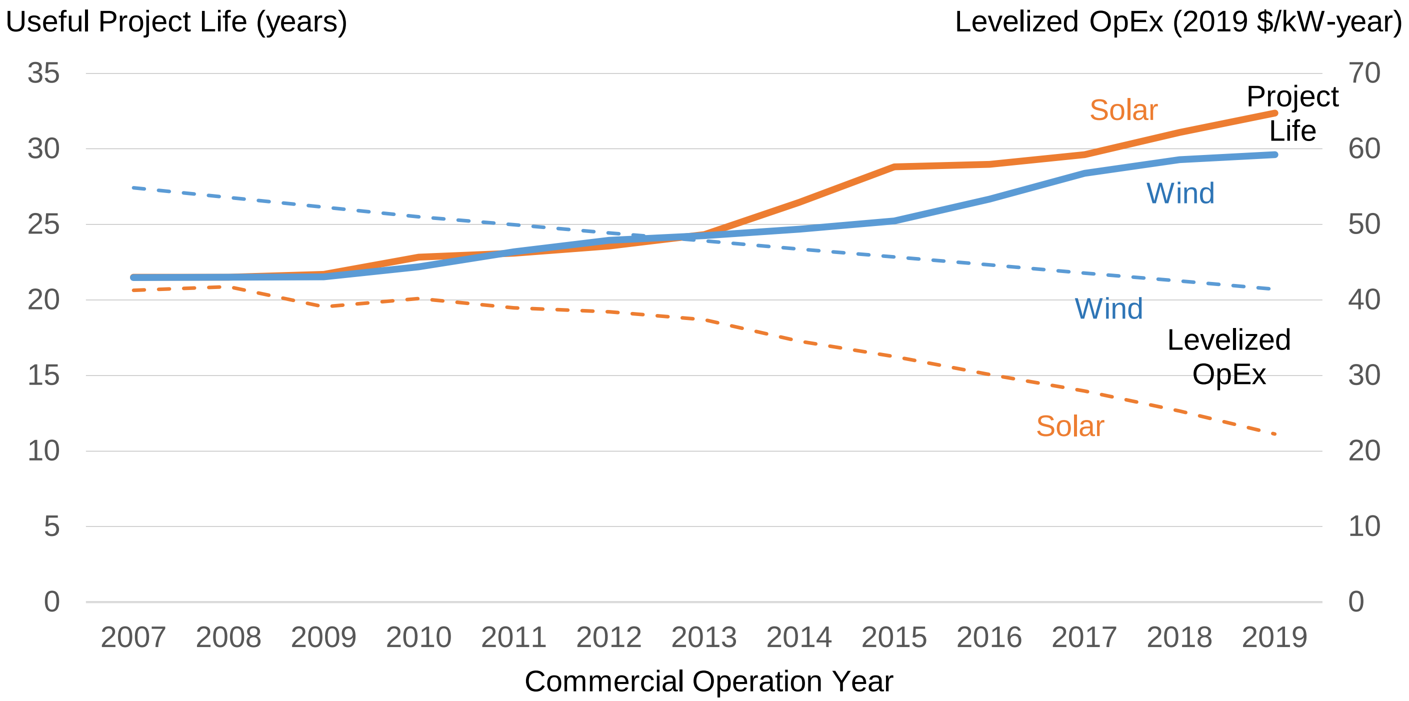
Utility-Scale PV Installed Costs



Wind's per-unit ($/W) costs have declined despite significant turbine scaling aimed at improving performance (i.e., larger rotors and taller towers to boost energy capture and capacity factor)

PV plants do not have this same performance-related scaling linkage—instead, efficiency improvements over time manifest almost exclusively in lower installed costs

"Survey says…" that operating expenses (OpEx) have steadily declined while assumed useful project life has lengthened

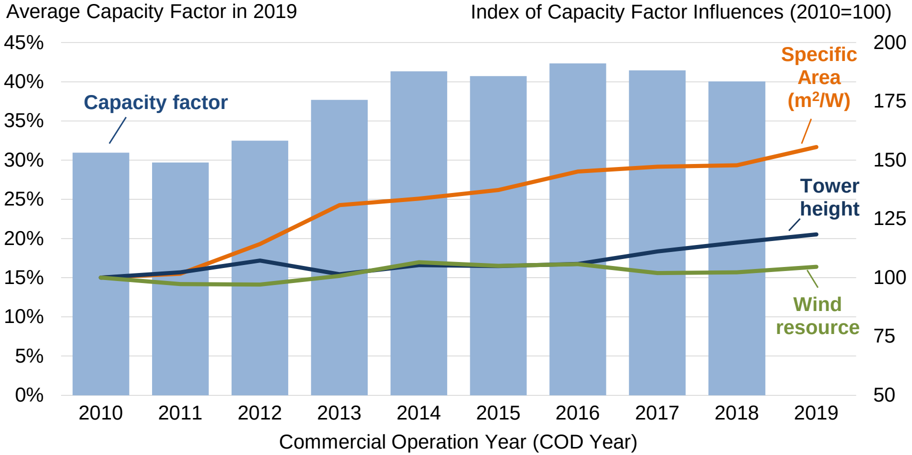


- A ~30-year life assumption is now common for both wind and solar
- Longer life and lower OpEx both reduce LCOE

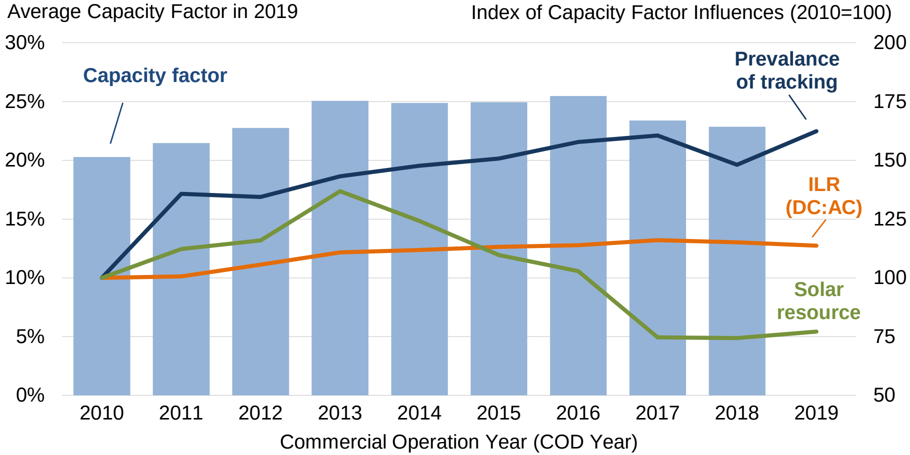
Because useful life and levelized OpEx are largely projections, we surveyed wind and solar developers, project owners, financiers, etc. for their views—the graph represents the average values from the survey

Newer wind and solar projects have performed better (as measured by capacity factor)

Wind Capacity Factor



Solar Capacity Factor



Wind:

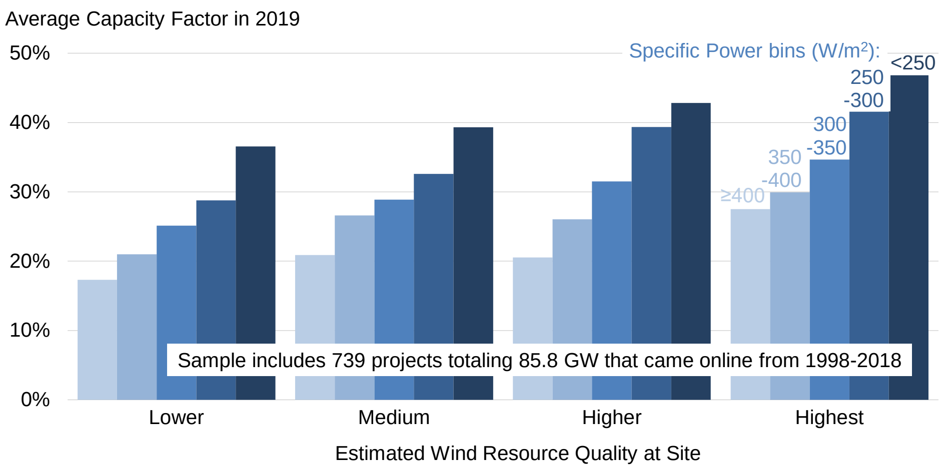
- Average capacity factor rose from ~30% to >40%, driven by an increase in the swept area of the rotor (m^2) relative to rated capacity (W)
- Tower height has increased only slightly—but that will change in the next few years with larger turbines

Solar:

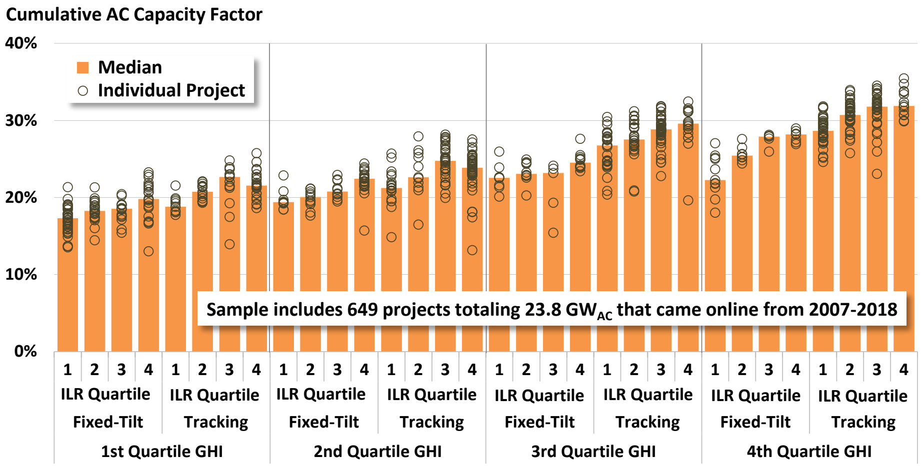
- 2010-2013: Average capacity factor rose from 20% to 25%, driven by higher inverter loading ratios (ILR), greater use of single-axis tracking, and buildout of sunnier sites
- Since 2013: Stagnant, as market expansion to less-sunny regions has offset the other two drivers

Capacity factor depends on resource quality—but also technology

Wind Capacity Factor



Solar Capacity Factor



Wind:

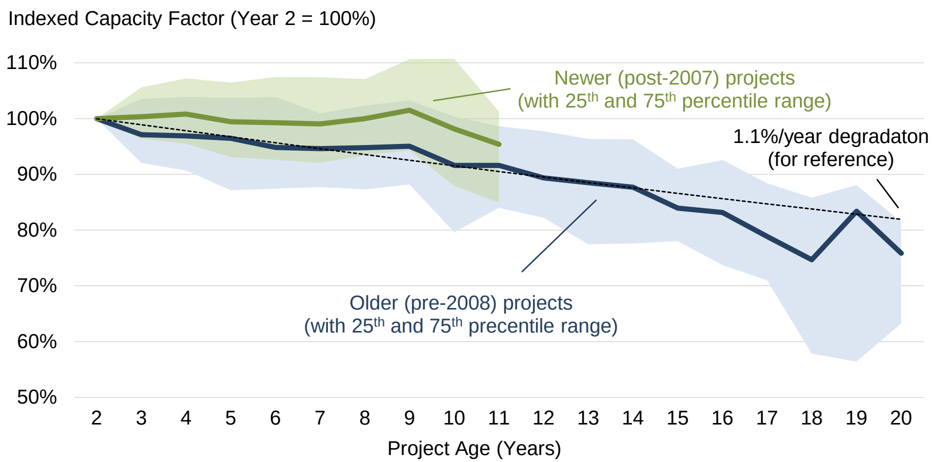
- As the swept area of a wind turbine's rotor (m^2) increases relative to its generator capacity (W), the "specific power" (W/m^2) of the turbine declines
- Reducing specific power boosts capacity factor as much as, or more than, moving to a better wind resource site

Solar:

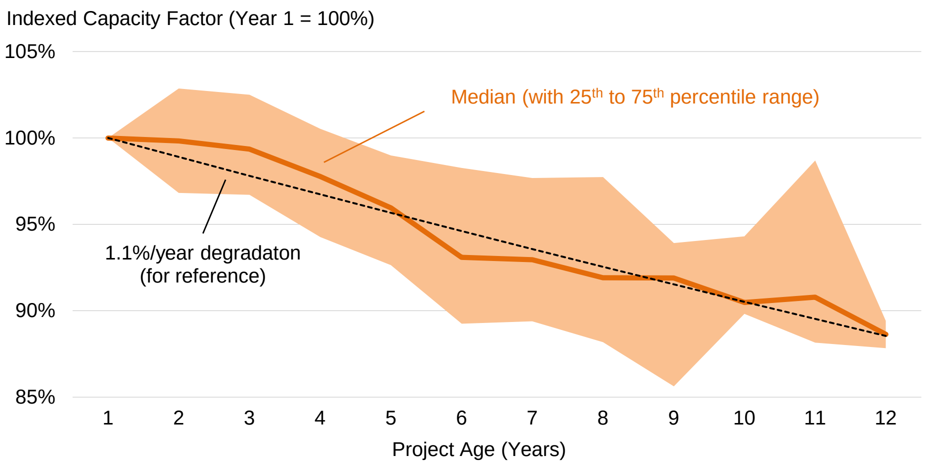
- Within each solar resource quartile (denoted by global horizontal irradiance or GHI), projects using single-axis tracking outperform fixed-tilt projects…
- …and projects with higher inverter loading ratios (ILR or DC:AC ratio) outperform projects with lower ILRs

The performance of both wind and solar declines as projects age
(both graphs control for inter-annual variation in the wind and solar resource)

Wind Performance Degradation



Solar Performance Degradation



Wind project performance seems to decline more significantly after the first decade

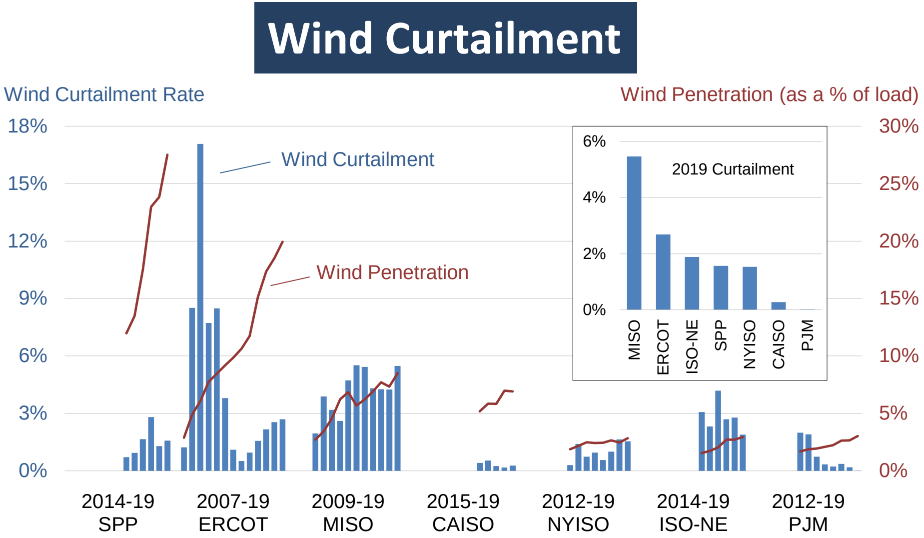
- 10-year PTC term, 10-year O&M contracts

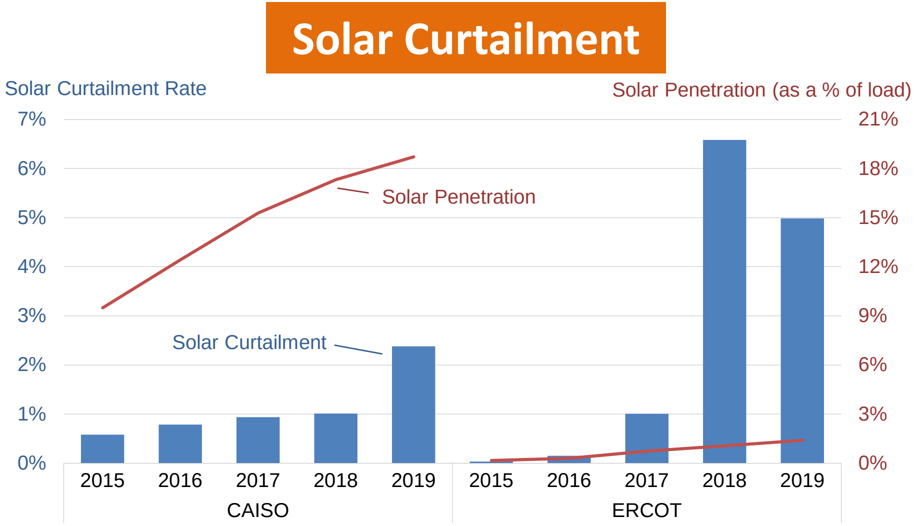
Newer projects seem to be degrading less

1.1%/year decline in project performance is worse than is commonly assumed

- **Note:** Neither the wind nor solar degradation graphs control for curtailment, which could be driving some of the trend

Wind and solar curtailment versus market penetration

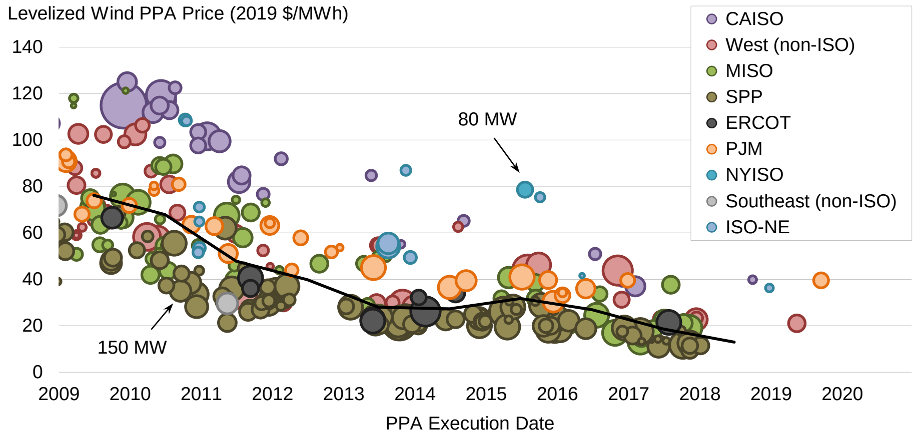




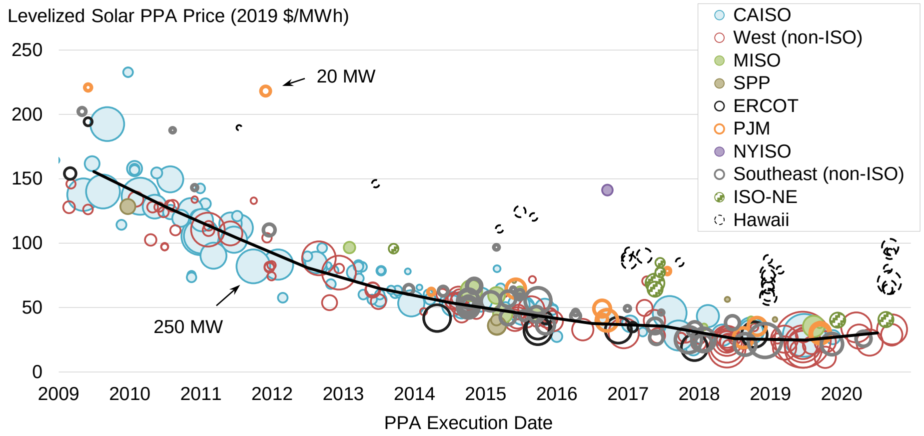
- All seven ISOs report wind curtailment, but only CAISO and ERCOT report solar curtailment (so far)
- Though curtailment can increase with market penetration, local congestion is a bigger factor:
  - **Wind:** Contrast ERCOT in 2009 (6% penetration and 17% curtailment) and 2015 (12% penetration and 1% curtailment)
  - **Solar:** ERCOT has much higher curtailment than CAISO in 2018 & 2019, but much lower penetration

The combo of lower CapEx/OpEx/finance costs and higher capacity factors and longer lives has driven power purchase agreement (PPA) prices to all-time lows

Wind PPA Prices

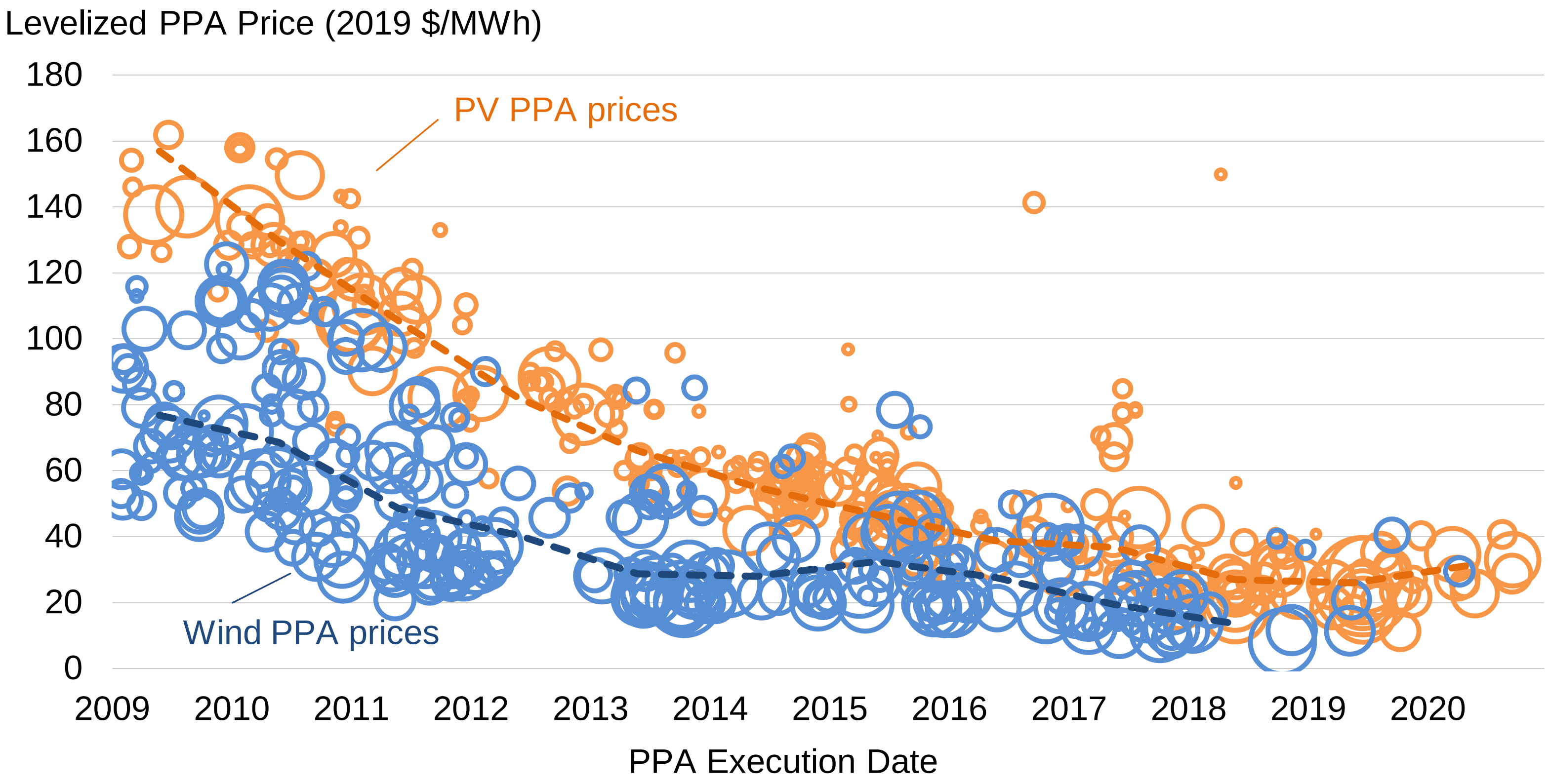


Utility-Scale PV PPA Prices



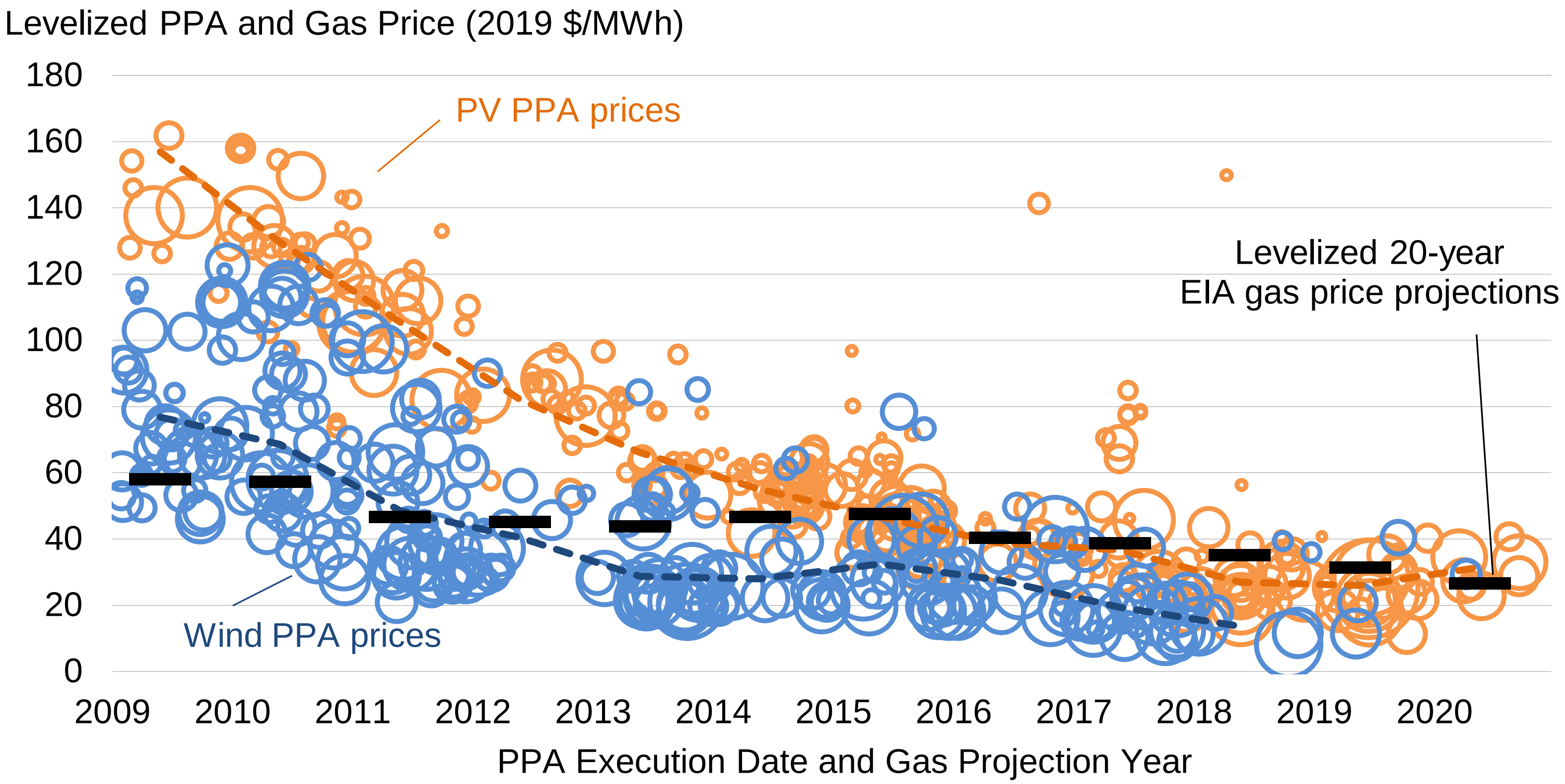
- Bubbles show levelized PPA prices by contract execution date (bubble size denotes PPA capacity)
- The black lines through the bubbles show generation-weighted average trend lines by calendar year
- Since 2009, average PPA prices have declined by ~80% for both wind and solar

Solar and wind PPA prices have converged over time, but solar is still more costly on average



The blue and orange dashed lines represent the generation-weighted average PPA price across years

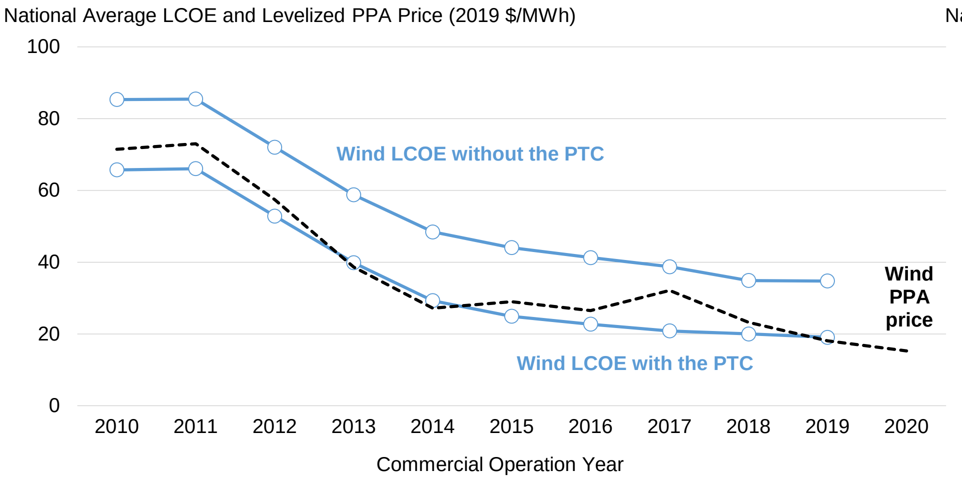
Wind and solar PPA prices are increasingly competitive with the cost of burning gas in an existing combined-cycle gas turbine



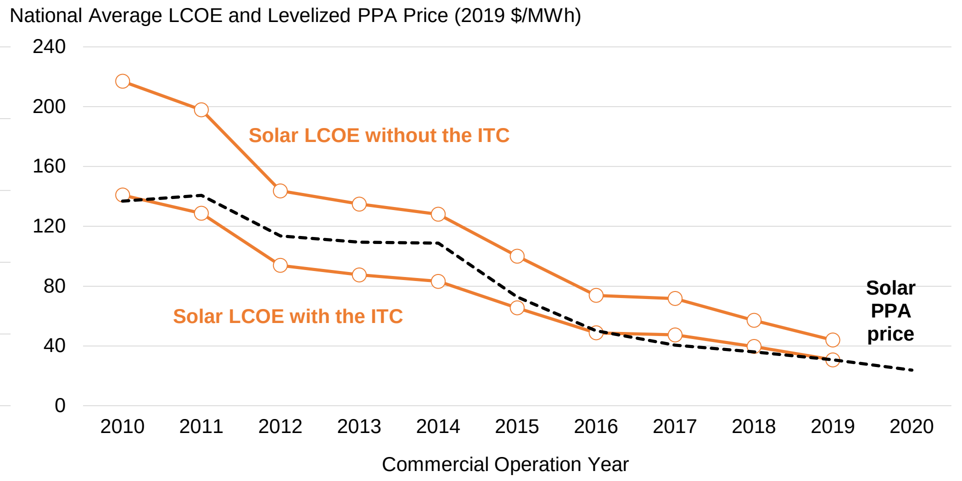
Black dashes represent the EIA's then-current delivered natural gas price projections over the coming 20 years, converted to $/MWh terms using a heat rate of 7.5 MMBtu/MWh and levelized at a real discount rate of 4%

LCOE estimates confirm PPA price trends and wind/solar convergence—implying a relatively efficient and cost-based PPA market

Wind LCOE and PPA Price



Solar LCOE and PPA Price



- LCOE typically does NOT reflect the receipt of tax credits—but credits can be factored in (though imperfectly—it's hard to capture financing effects)
- The relatively close agreement between LCOE with tax credits and PPA prices suggests full pass-through of the credits and an efficient, cost-based, competitive market for PPAs

But cost is only half the story…also need to consider "market value"

Market value can be thought of as the revenue that a merchant wind or solar plant would earn by selling all of its generation into real-time wholesale markets.

Or, for plants with long-term, fixed-price PPAs, market value equals the buyer's avoided cost (i.e., what the buyer would have otherwise paid for the same quantity and timing of MWh in real-time markets).

We analyze the two main sources of wholesale market value:

Energy value = Σ (hourly energy price $*$ hourly generation)

Capacity value = Σ (capacity credit $*$ capacity price) / MWh

- Capacity credit is based on wind or solar's contribution to meeting resource adequacy requirements

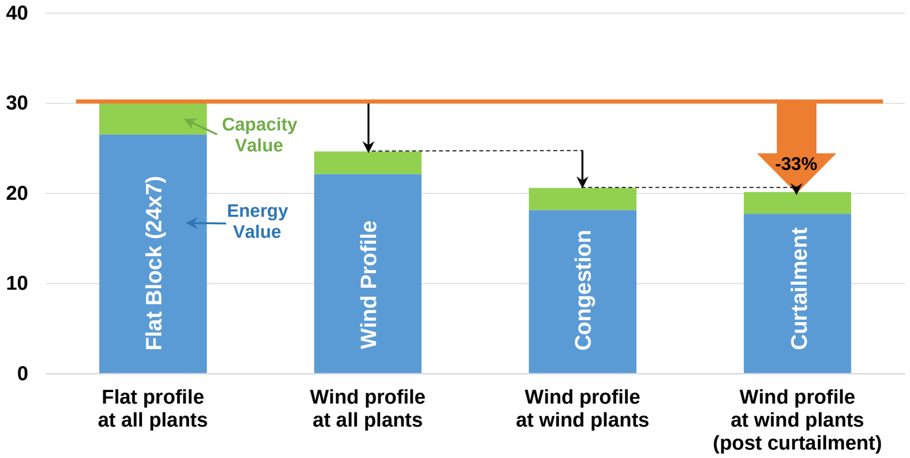
Wholesale market value depends on:

1) Hourly ***generation profiles*** of wind and solar, and how they align with hourly ***price profiles***
2) Energy and capacity prices at the ***location*** of wind and solar plants, considering ***congestion***
3) The extent to which wind and solar experience ***curtailment***

Solar's market value exceeds wind's (on a nationwide, annual average basis)

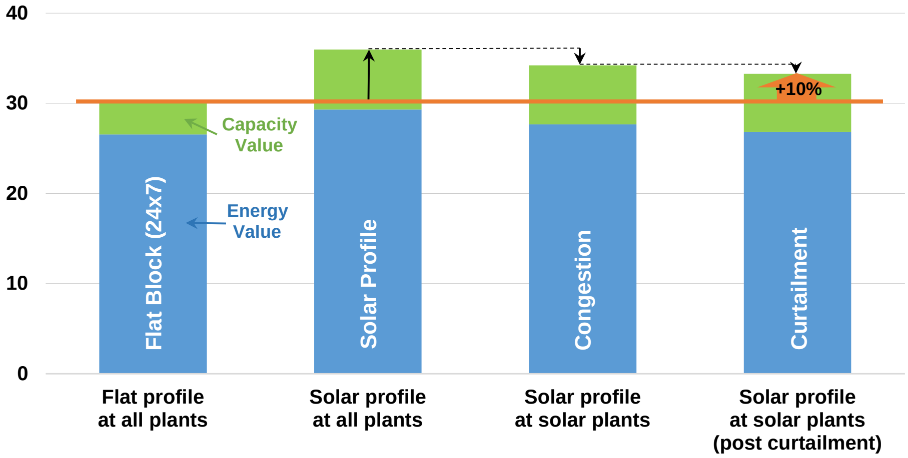
Wind Market Value

Wind Market Value in 2019 (2019 $/MWh)



Solar Market Value

Solar Market Value in 2019 (2019 $/MWh)

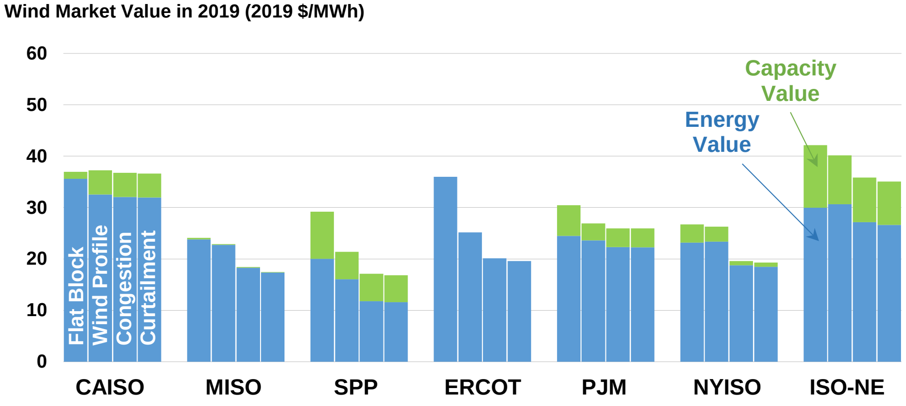


- In 2019, wind's market value (energy + capacity value) was $20/MWh
  - ➢ 33% below that of a 24x7 "flat block" of power ($30/MWh)
- Wind's value was hurt the most by profile and congestion, less so by curtailment

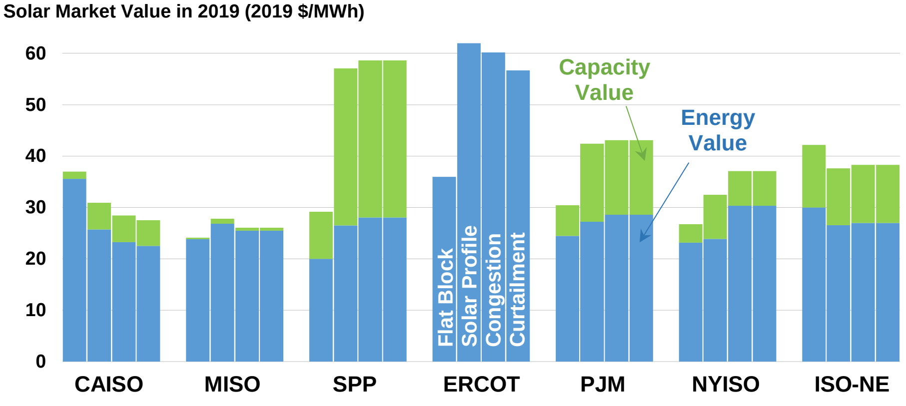
- In 2019, solar's market value (energy + capacity value) was $33/MWh
  - ➢ 10% above that of a 24x7 "flat block" of power ($30/MWh)
- Solar's value was *helped* by profile but hurt by congestion and curtailment

Can make the same comparison, and examine the same drivers, by ISO: In 2019, the value of wind and solar varied substantially across the country

Wind Market Value

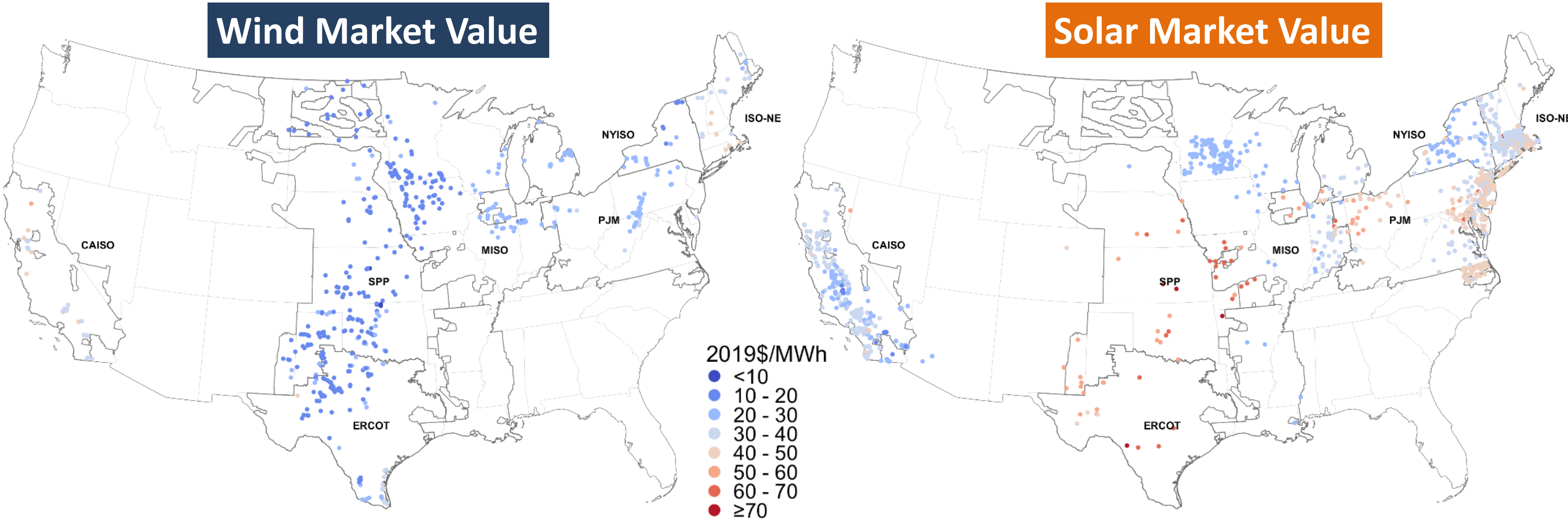


Solar Market Value



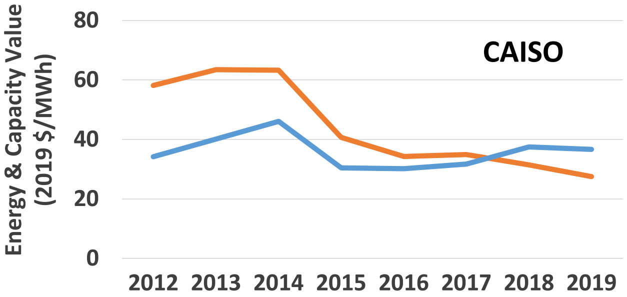
- **Wind:** Only in CAISO does wind's market value approximate a 24x7 flat block (both ~$37/MWh)
- **Solar:** Except for CAISO and ISO-NE, solar's value exceeds a 24x7 flat block in all other ISOs
- In 2019, solar was worth more than wind in all ISOs except CAISO
- For both wind and solar, profile is generally the largest driver of value, but congestion/location is also important (and more so for wind than solar)

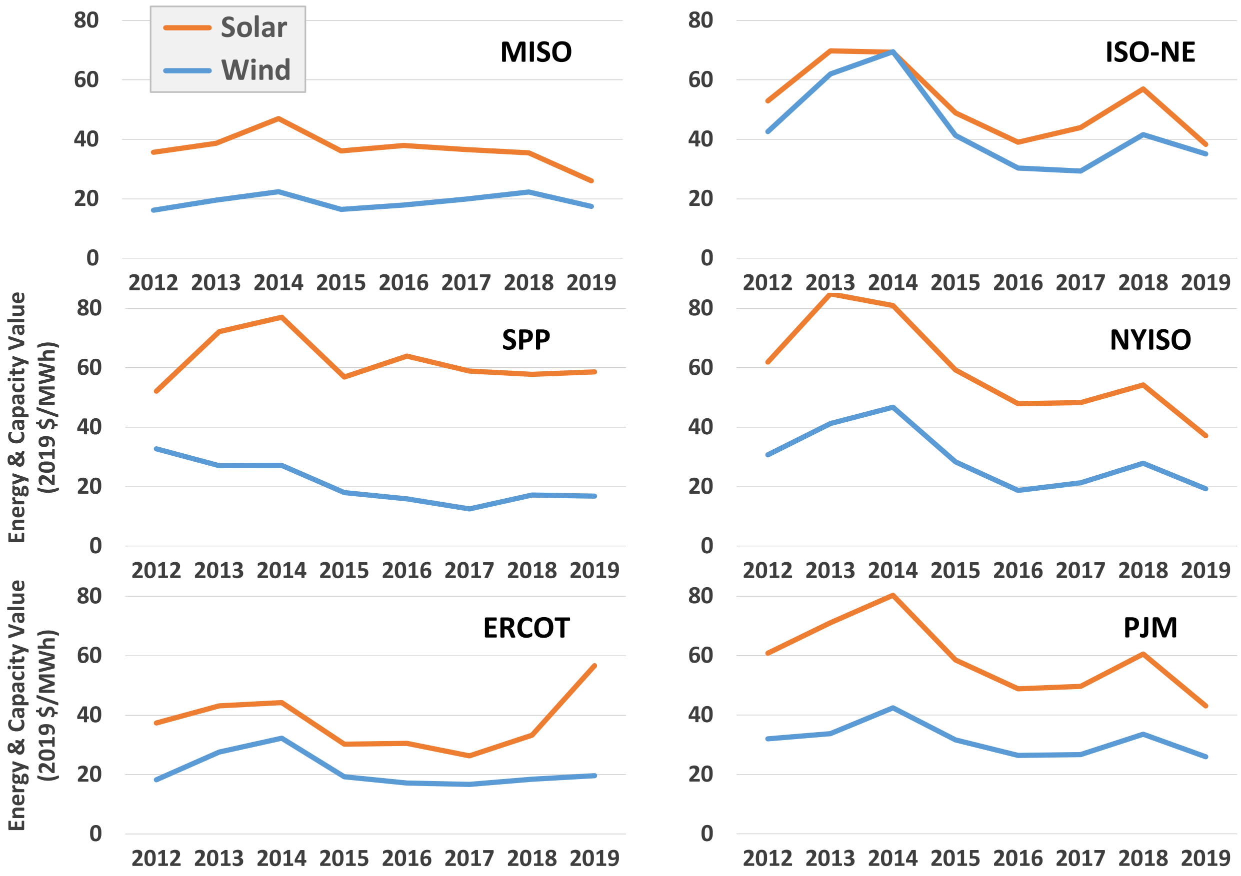
Project-level data show variation in market value even *within* ISOs



- Wholesale market value tends to be lowest where market penetration is highest
  - Interior (ERCOT, SPP, MISO) for wind
  - Southwest (CAISO) for solar
- But value can be low even in low-penetration markets, simply due to low wholesale prices
  - Solar in MISO and NYISO

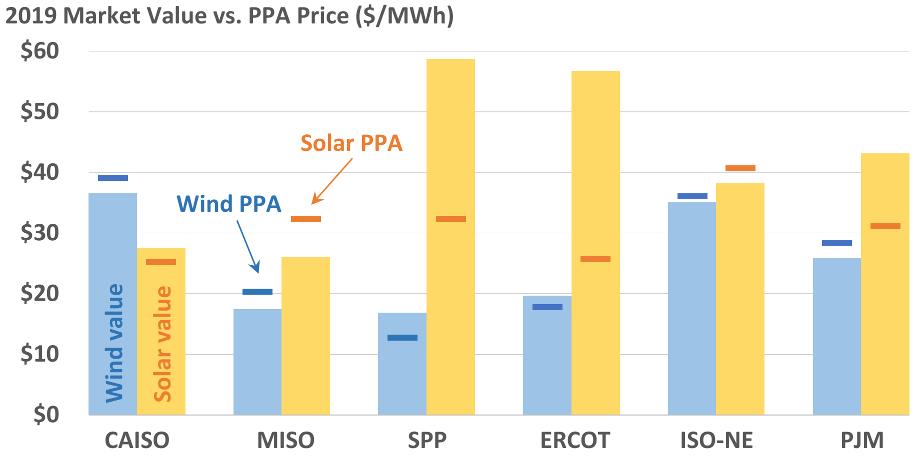
Solar’s greater value has generally persisted over time (except in CAISO)

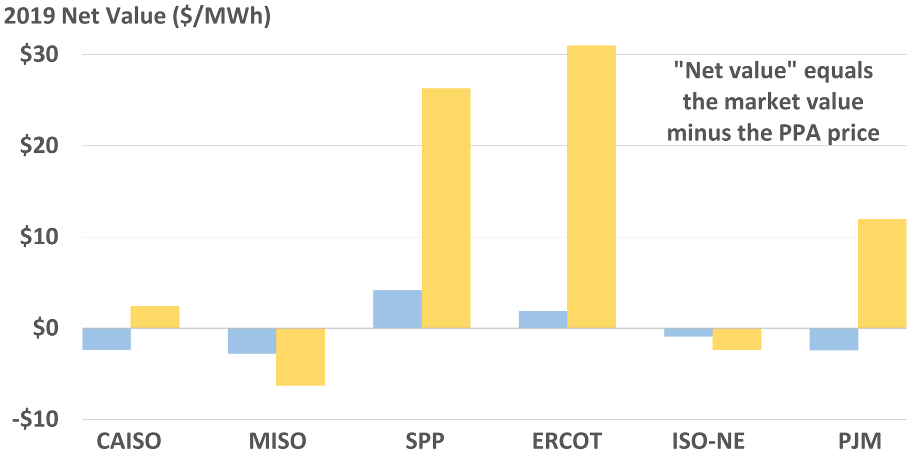




- In CAISO, increasing penetration has reduced solar’s value, to the point where it’s now worth less than wind
- In the other six ISOs, solar has consistently been worth more than wind back through 2012
  - ➢ Value gap is narrowest in ISO-NE, where peak pricing typically occurs during winter heating months, when solar output is low
  - ➢ ERCOT solar value in 2019 helped by ORDC and price spikes

After netting out PPA prices, solar still provides positive "net value" in many regions (and often higher net value than wind)

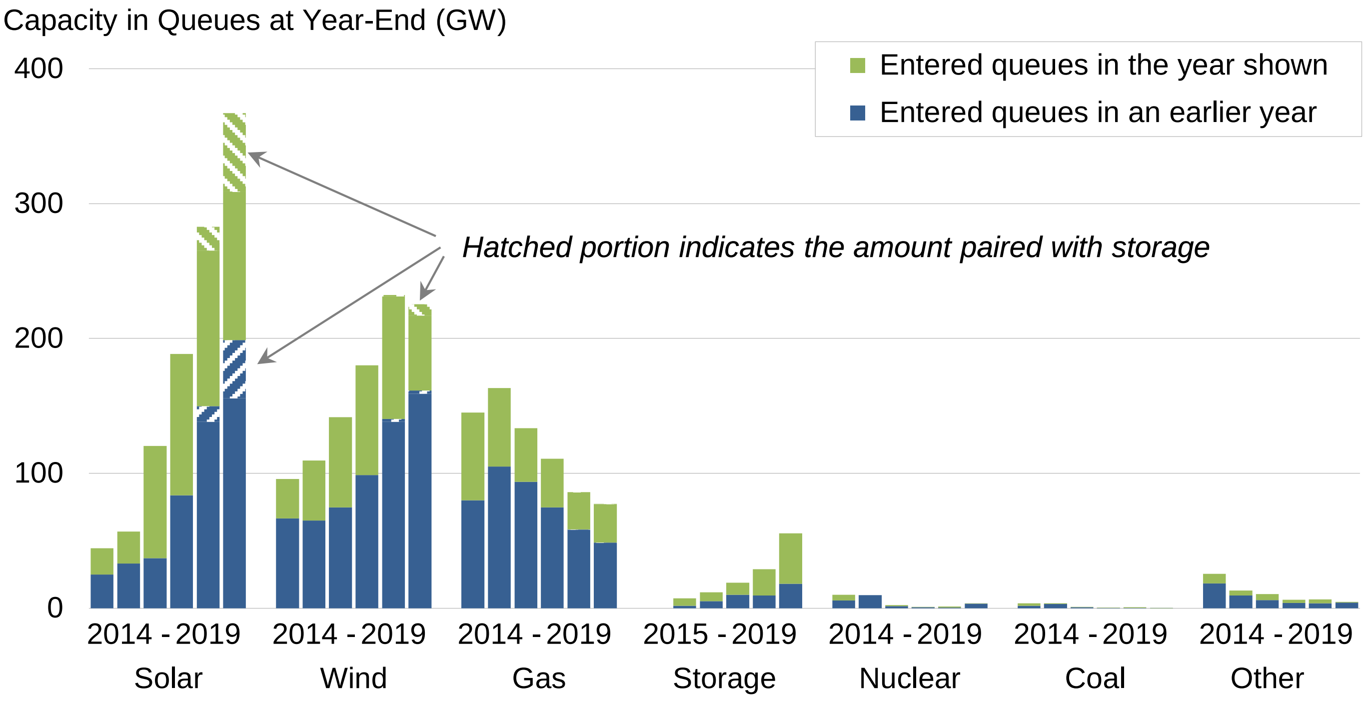




- The graph on the left plots average wind and solar PPA prices from a sample of recent contracts (dashes) against 2019 wind and solar market value (columns)
- **Except for in CAISO, solar is more expensive than wind, BUT is also more valuable than wind**

- The graph on the right subtracts the PPA prices from the 2019 market value, to show "net value" by ISO
- **Solar has positive net value, and greater net value than wind, in 4 of the 6 ISOs shown**
  - ➢ MISO and ISO-NE are the exceptions

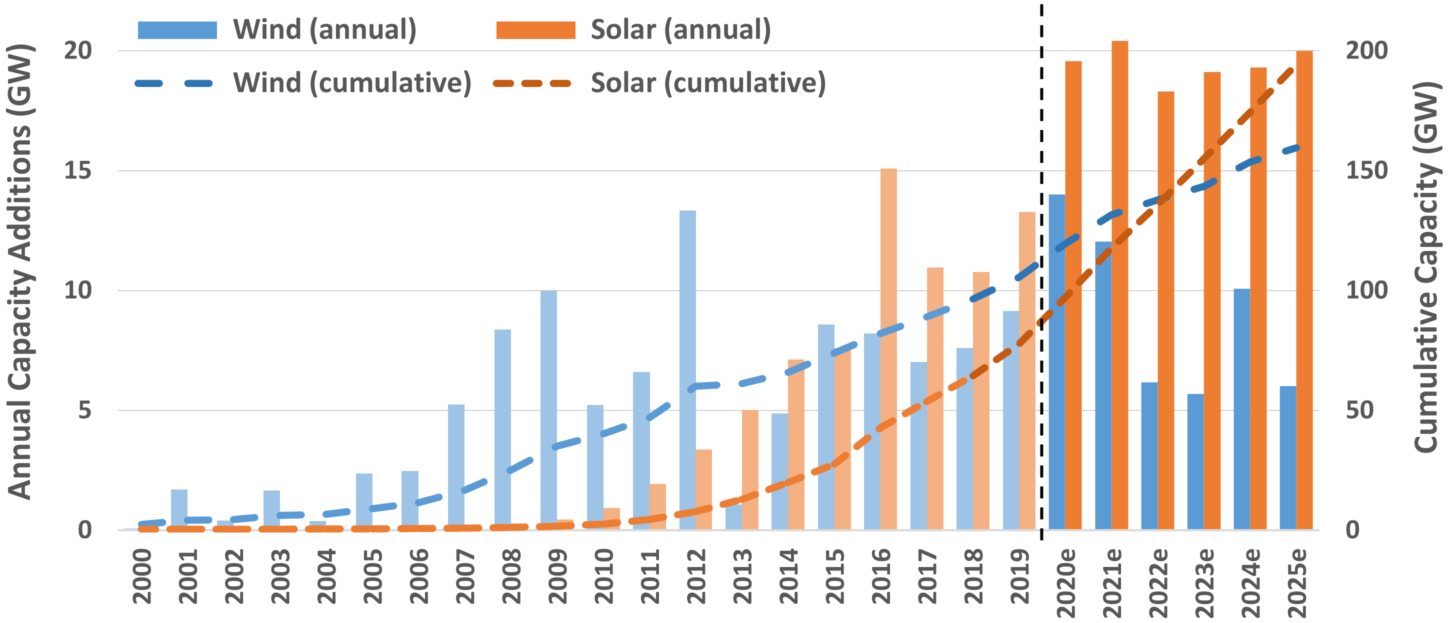
Which is partly why solar has rocketed to the top of grid interconnection queues across the country



Not all of this capacity will be built—much of it will languish in the queues

- These 37 queues cover ~80% of non-coincident demand in the U.S.
- Solar, storage, and—until 2019, wind—have been growing; everything else declining
- Solar ranked 3rd in the queues as recently as 2016, but is now 1st by far
- 28% of PV capacity in the queues is paired with battery storage (compared to just 5% of wind capacity)

And is why analysts project cumulative solar capacity to surpass wind by 2023



The projected deployment patterns are also driven in part by the phase-down of federal tax credits (e.g., wind drops off post-2020, as the PTC phases out, while solar retains the 30% ITC through 2023)

- Wind projections represent the average of 4 different analysts
- Solar projections are solely from Wood Mackenzie, and include both distributed and utility-scale solar

But a number of headwinds could slow market growth

Phase-down of federal tax credits

Macroeconomic factors (tariffs, exchange rates, interest rates)

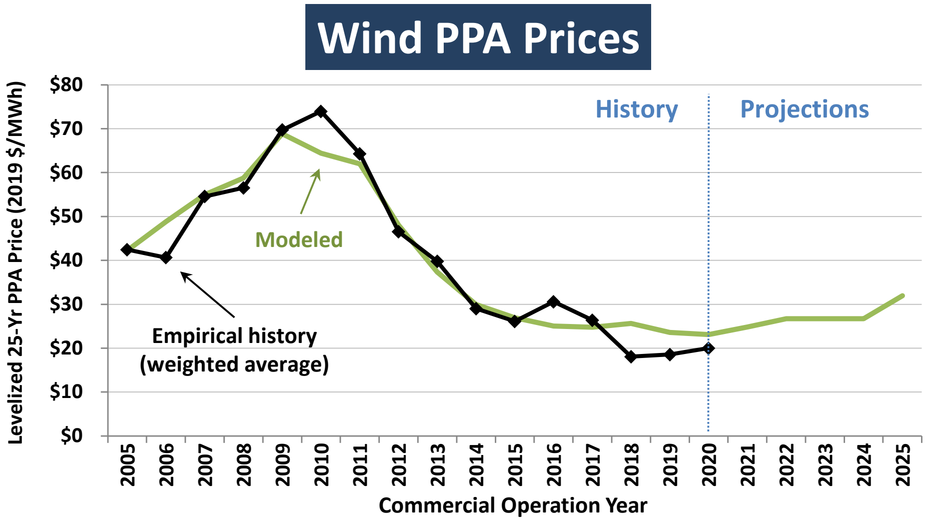
Low-cost natural gas a potent competitor

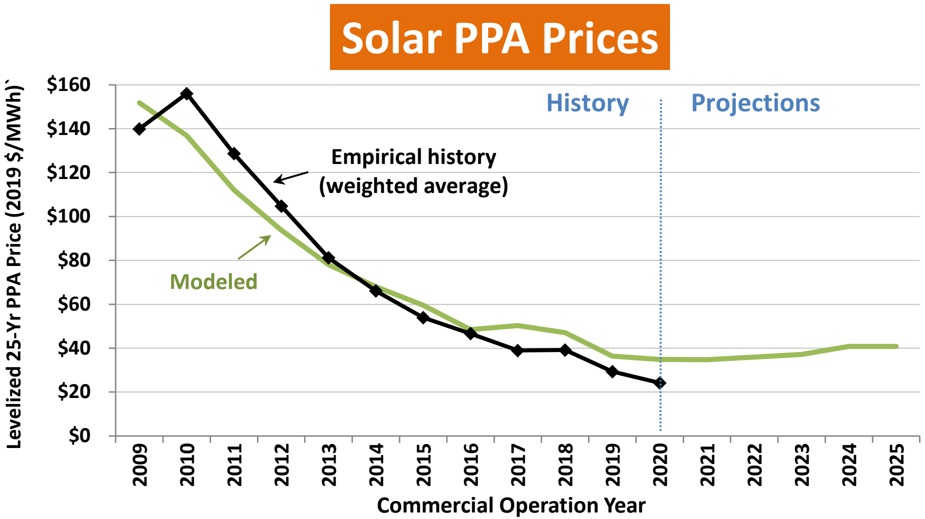
Modest electricity demand growth in most regions

Inadequate transmission in some locations

Market saturation (and value decline) absent proactive grid integration

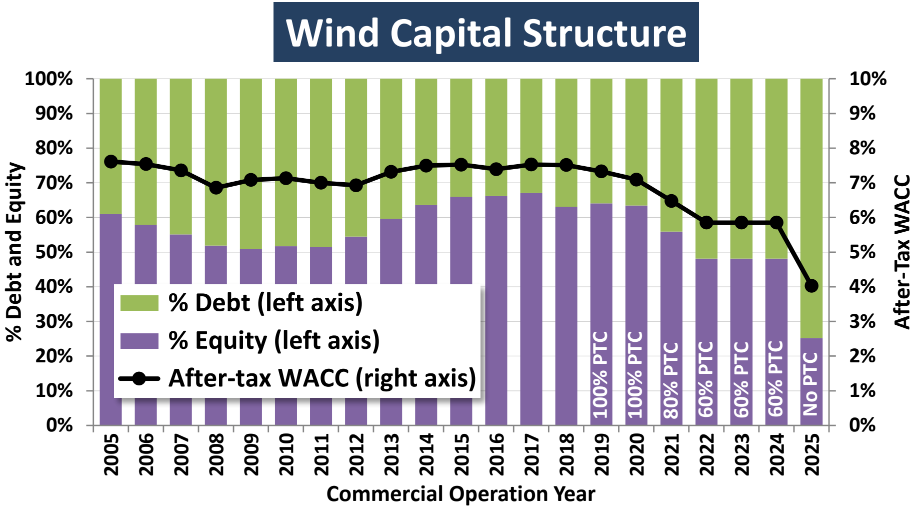
All else equal, tax credit phase-out will cause PPA prices to increase

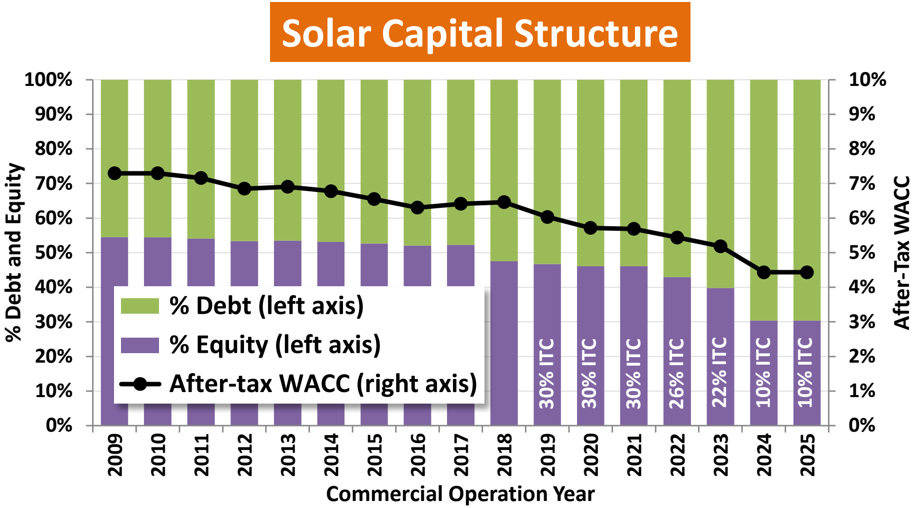




- Modeled PPA prices (based in part on the empirical CapEx and capacity factor data presented earlier) match empirical history reasonably well—which suggests we can use the model for forecasting purposes
- Holding all inputs constant going forward ***except for tax credit phase-out*** suggests that, all else equal:
  - **Wind PPA prices could increase by $9/MWh (+39%) by 2025**
  - **Solar PPA prices could increase by $6/MWh (+17%) by 2025**

Projected wind and solar PPA price increases would be twice as large if not for a favorable shift in capital structure (i.e., debt/equity ratio)

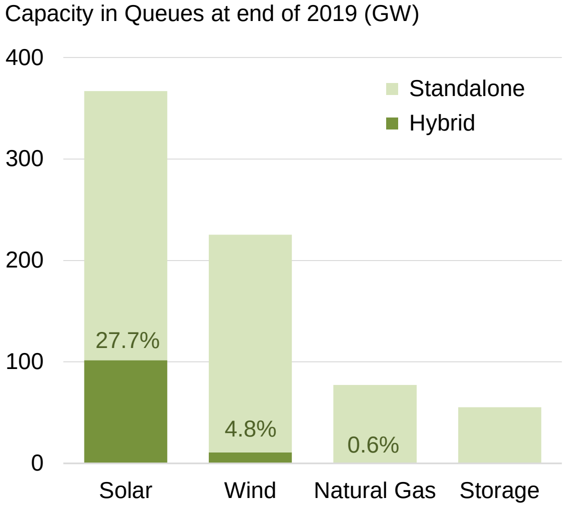




Without the tax credits, wind and solar projects can support more lower-cost debt (green bars)

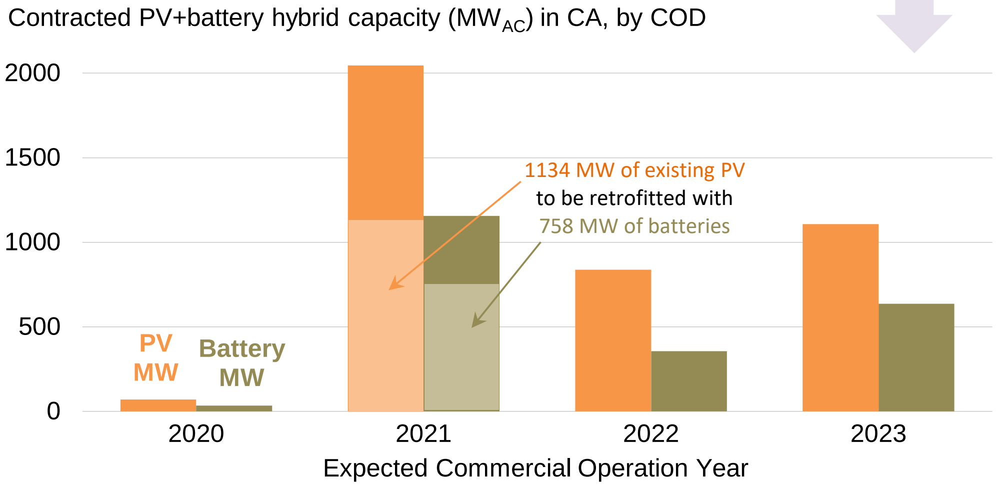
- As a result, the projected 2025 weighted-average cost of capital (WACC) is **3.0 (for wind)** and **1.3 (for solar)** percentage points ***lower*** than it is in 2020
- If 2025 had the same capital structure as 2020, then 2025's PPA price increase would be even greater:
  - **An additional $10/MWh (+33%) for wind (for a total of +$19/MWh, or +84%)**
  - **An additional $7/MWh (+18%) for solar (for a total of +$13/MWh, or +38%)**

Antidote for market saturation? Strong interest in adding battery storage—particularly to solar projects, and particularly in CAISO

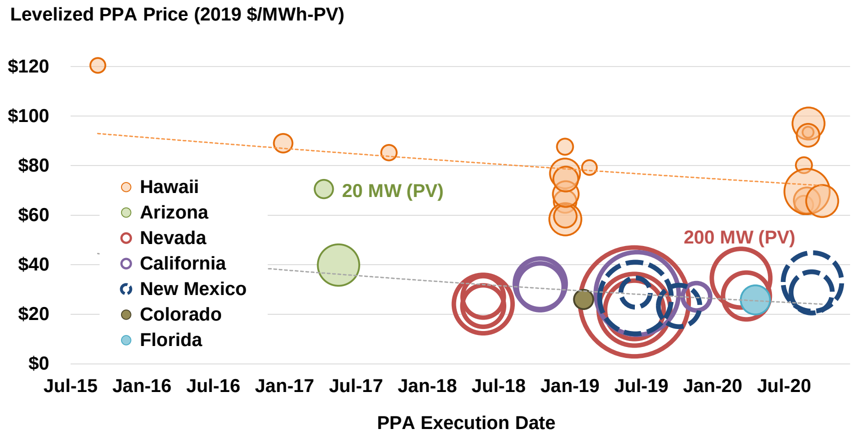


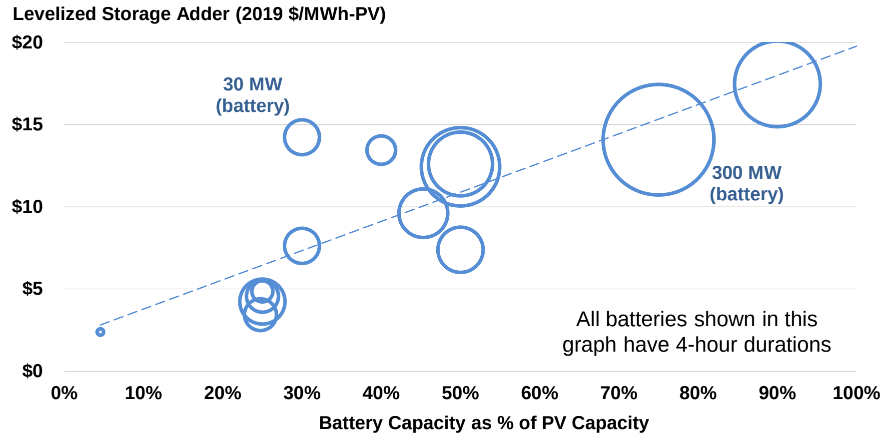
- Interconnection queue data show 28% of all PV capacity in the queues is paired with battery storage (compared to just 5% of wind capacity)—much of this hybrid capacity is in CAISO's queue
- Though queue data are highly speculative, PPA announcements are less so—and suggest that ***at least*** 2.2 GW of battery storage will be built in CA through 2023 as part of PV hybrid plants

Region	Percentage of Proposed Generators Hybridizing in Each Region		
	Solar	Wind	Nat. Gas
CAISO	67%	50%	0%
ERCOT	13%	3%	0%
SPP	22%	1%	0%
MISO	17%	2%	0%
PJM	17%	0%	1%
NYISO	5%	1%	4%
ISO-NE	0%	6%	0%
West (non-ISO)	50%	6%	0%
Southeast (non-ISO)	6%	0%	0%
TOTAL	**27.7%**	**4.8%**	**0.6%**



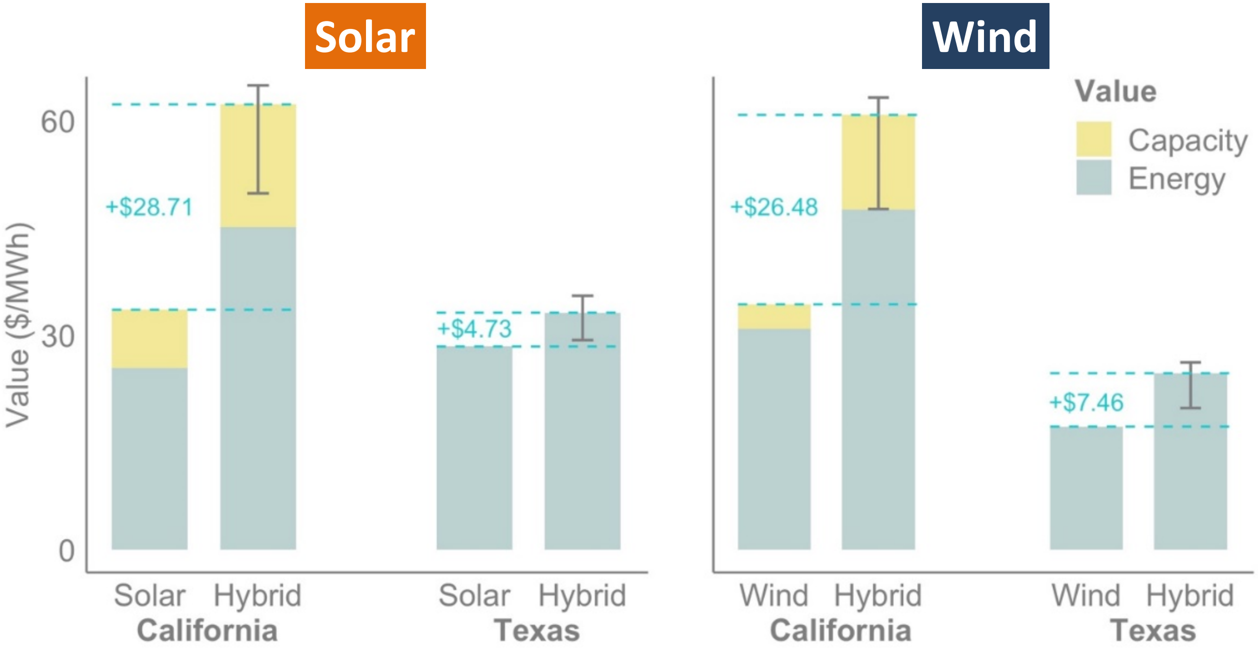
Growing interest in hybridization stems from falling costs, modest adder…





- Top graph shows levelized PPA prices for 40 PV+battery projects in Hawaii (orange circles and trend line) and on the mainland
  - ➢ Recent mainland projects are priced around $30/MWh (levelized in real dollar terms)
  - ➢ Wide range of configurations: batteries have 2-8 hour durations and battery:PV capacity ratio varies from 5-100%
- 14 of these 40 PPAs break out the PV and battery pricing, enabling us to calculate the incremental cost of adding batteries—i.e., the "levelized storage adder"
- Bottom graph shows that the "levelized storage adder" increases linearly with the battery:PV capacity ratio
  - ➢ ~$5/MWh-PV at 25% battery:PV capacity, ~$10/MWh at 50%, ~$20/MWh at 100%
  - ➢ One project developer thinks of (and markets) this as paying an extra ~$10/MWh for "near-firm" renewables

…and strong value proposition, particularly in solar-saturated grids like CAISO



- LBNL analysis of adding a 4-hour duration battery (sized to 50% of PV nameplate capacity) to a standalone PV project increased overall market value by >$28/MWh in CAISO
  - ➢ This value boost exceeds the empirical ~$10/MWh storage cost adder discussed on the previous slide
  - ➢ Similar value boost for wind, in CAISO

- Value of hybridization is less-evident in ERCOT (which has no capacity market, and where solar has a much lower market share)

Summary

- A combination of lower CapEx, lower OpEx, lower finance costs, better performance, and longer economic lives have driven utility-scale wind and solar PPA prices and LCOE to all-time lows
  - ➢ Historically, solar has cost more than wind, but their PPA prices (and LCOE) have converged in recent years
  - ➢ Current wind and solar PPA prices are often competitive even with just the cost of burning fuel in an efficient natural gas combined cycle unit (i.e., a portion of NGCC operating costs)—*despite historically low gas prices*
- The wholesale market value of wind and solar tends to decline as market penetration increases
  - ➢ To date, declining PPA prices have largely kept pace with the erosion of wind and solar's market value
  - ➢ After netting out PPA prices, solar tends to offer greater "net value" than wind (except in CAISO)
- Looking ahead, the phase-down of federal tax credits will push wind and solar PPA prices higher (all else equal) as wind and solar's market value likely continue to decline with growing market share
  - ➢ A fortuitous shift in the debt/equity ratio as tax credits fade will mitigate some of this PPA price increase
  - ➢ Hybridization by adding battery storage can help boost wind and (particularly) solar's market value—*driving strong interest from the market*

Thanks for tuning in! Questions?

Wind Energy Technology Data Update: 2020 Edition

- Ryan Wiser (rhwiser@lbl.gov), Mark Bolinger (mabolinger@lbl.gov), Ben Hoen, Dev Millstein, Joe Rand, Galen Barbose, Naïm Darghouth, Will Gorman, Seongeun Jeong, Andrew Mills, Ben Paulos

- Excel data file with embedded graphics, slide deck briefing, and interactive data visualizations: ***windreport.lbl.gov***

Utility-Scale Solar Data Update: 2020 Edition

- Mark Bolinger (mabolinger@lbl.gov), Joachim Seel (jseel@lbl.gov), Dana Robson, Cody Warner

- Excel data file with embedded graphics, slide deck briefing, and interactive data visualizations: ***utilityscalesolar.lbl.gov***

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