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Overbuilding & curtailment: The cost-effective enablers of firm PV generation

Marc Perez[a], Richard Perez[b,*], Karl R. Rábago[c], Morgan Putnam[a]

[a] Clean Power Research, United States
[b] University at Albany, United States
[c] Pace University Energy and Climate Center, United States

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ABSTRACT

Current thinking considers that PV output curtailment is a last resort measure to be avoided. In this article, we argue that supply-shaping, achieved through proactive curtailment associated with PV oversupply, is actually critical to achieving intermittency mitigation and delivering firm PV generation at the lowest cost.

We investigate the premium to transform a low-cost, but intermittent solar kWh into a firm, effectively dispatchable kWh. We show that a fundamental ingredient of minimizing this premium is to optimally overbuild and, as necessary and appropriate, curtail PV generation. Drawing on a case study in the State of Minnesota, we show that firm, high-penetration-ready PV generation could be achieved at a production cost at or below current conventional generation, especially when optimally coupled with wind generation.

We conclude with a recommendation that in order to achieve this lowest cost firm generation potential, proactive curtailment strategies should inform future transactional PV remuneration systems.

1. Introduction

Solar PV is rapidly becoming one of the least expensive technologies to generate electricity on a pure energy (kWh) basis (e.g., Fortune Magazine, 2016).

Because PV is a variable generation resource, the associated low-cost PV kWh is considered by resource planners to be an intermittent kWh. Solar power is not dispatchable a priori: It is subject to the earth's rotation, axial tilt, and the movement of clouds across its surface. Firm power generation guarantees are a prerequisite to enabling high PV penetration, displacing conventional generation, and securing high market value compensation. Fig. 1 offers a familiar depiction of the intermittencies of PV generation in relation to typical electrical load demand on intraday and annual bases, and qualitatively points to the challenges of matching the PV supply to the demand.

The subject of renewable resources' intermittency mitigation in the context of increasing grid penetration has generated and continues to generate an abundant literature.

Many contributions can be characterized as "bottom-up", i.e. approaching the question from a dispersed resources perspective and focusing on strategies to facilitate intermittent renewable power flows on distribution grids relying largely on localized storage strategies, demand management and intelligent controls to address issues such as reverse power flows, e.g., Olowu et al., 2018; Sarkar et al., 2018; Baum et al., 2019.

Other contributions approach the subject of high penetration as a comprehensive mix of multiple supply-side interventions and demand-side management resources. Among these models/approaches to analyzing a high-penetration renewable future, the most widely cited approach is that of Jacobson and Delucchi at Stanford (Jacobson et al., 2011a, 2011b). In this study, the authors investigate a wind water and solar solution to meet all primary energy demand by 2050. This approach has recently been heavily critiqued, particularly with respect to the assumptions surrounding available marginal hydropower resources. (Clack et al, 2017). Along these lines, Powell's team at Princeton (Powell and Khazaei, 2015; Powell et al., 2011; Kim and Powell, 2011) proposed a stochastic-dynamic model known as SMART that attempts to optimize capacity allocations and dispatch of renewable resources for meeting load or mitigating variability. The firm power generation concept is not discussed.

Our approach, by contrast, could be characterized as "top-down" with the underlying assumption that supply-side PV generation, once firmed-up, can be seamlessly integrated into existing power grids because it becomes functionally equivalent to current conventional [firm]

* Corresponding author.
E-mail addresses: marcP@cleanpower.com (M. Perez), rperez@albany.edu (R. Perez), krabago@law.pace.edu (K.R. Rábago), morgan@cleanpower.com (M. Putnam).

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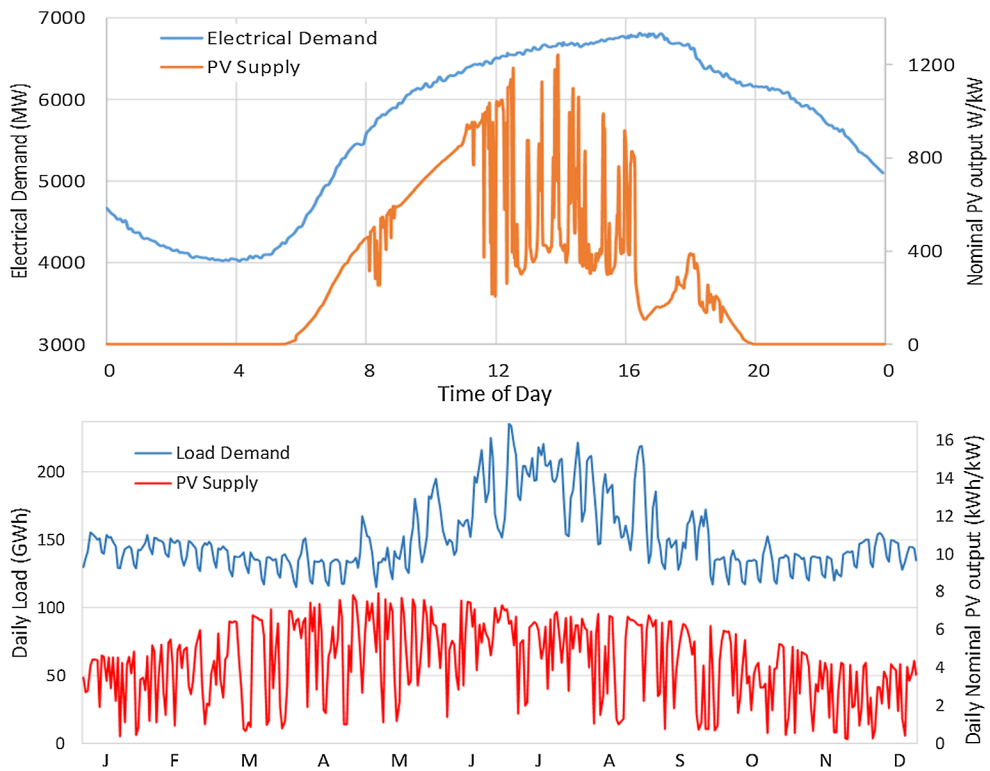

Fig. 1. Intraday (top) and intra-annual (bottom) PV supply intermittency in the New York metro area compared to city-wide electrical load requirements.

power generation resources. We show that the economics of this approach are solid and that a transition to very-high penetration PV could occur—given projected continued cost declines of both PV and storage—without a demonstrable increase in electricity production costs.

Closer in modeling approach to that taken in this paper is the work of Budischak at Delaware Technical Community College (Budischak et al., 2013). Budischak and coauthors do identify the value of leveraging the relative deployment of wind and solar and of oversizing these renewable generation assets as a pathway to low-cost load matching and reduction in storage deployment. However they do not explicitly seek to deliver firm power and optimize RE overbuilding/curtailing as they capacity constrain resources, and do not develop an optimized gas dispatch schema as discussed here, relying on the gas portion of the existing load dispatch stack to soak up some of the otherwise curtailed RE electricity.

The concept of curtailment is also approached, but reactively, as a result of RE (wind) capacity constraint (Simao et al., 2017) or as something, to be avoided (Archer et al., 2017).

Our approach has at its core a concept of firm, effectively dispatchable renewable generation. Given the projected further cost declines, massive global resource and intrinsic modularity of PV, we believe PV in particular to be core of a renewable future generation schema and we designed our model around this concept.

The paper first approaches the concept of firm power generation and places it in the context of prevailing current practice (i.e., avoiding curtailment). We then introduce optimal curtailment as an effective means to achieve lowest-cost firm power generation for a single power plant (Section 3). In Section 4, we show that geographic resource dispersion (multiple plants), load flexibility achieved by allowing a small amount of natural gas, and optimum blending with wind power generation can drive lowest-cost firm power generation in a range that is comparable to current conventional generation cost on a straight business basis. In Section 5, we discuss the implications of our findings on PV remuneration pathways and PV deployment logistics.

2. Firm power generation

Closing the performance and value gap between PV generation and market demand is key to maximizing the solar value proposition. In this paper, we define a 'firm kWh' as a kWh that can meet given demand specifications with 100% certainty.

We define the *Firm kWh Premium* as the ratio of the breakeven levelized cost of electricity (LCOE) of a firm kWh and the LCOE of an unconstrained, as-available (i.e., intermittent) PV kWh. This is shown in Eq. (1). The firm premium is an essential metric to relate often quoted [unconstrained] PV kWh costs to fully dispatchable conventional generation kWh costs.

$$Firm\ \ kWh\ \ Premium = \frac{Firm\ \ PV\ \ LCOE}{Unconstrained\ \ PV\ \ LCOE} \tag{1}$$

The unconstrained LCOE is a function the capital (CapEx) and operating (OpEx) costs of a PV plant as well as of the energy yield of that plant. The firm LCOE also embeds the additional CapEx and OpEx of the technologies and strategies required to transform the intermittent kWh into a firm, on demand kWh. These technologies and strategies include energy storage, distribution automation, high-precision forecasting, load-shaping/demand modification, and, all importantly, as argued here: oversizing coupled with proactive curtailment.

We recently introduced four operational solutions can effectively transform intermittent solar into a firm power generation resource without relying on conventional backup power generation (Perez, 2015; Perez et al., 2016a). These solutions include electrical energy storage, supply oversizing/curtailment, load shaping, and geographic dispersion via grid strengthening. An optimum blend of these solutions has the potential to deliver operational guarantees at an all-inclusive cost approaching that of conventional generation.

One of these solutions is *supply overbuilding/curtailment*. While the paper quantitatively addresses all above-mentioned solutions, our primary focus is placed on this apparently wasteful curtailment solution.

Electricity sector economics have long been driven by high capital costs. Utility regulatory frameworks have addressed this basic reality with a business model and regulatory structure that rewards and incentivizes capital investment in conventional generation resources and associated infrastructure, sometimes to the point of overbuilding (Averch and Johnson, 1962). For the first several decades of solar PV market development, the cost of generation capacity ($ per watt) and relatively low energy prices ($ per MWh) have driven PV investment decisions as well. As a result, tradition dictated that overbuilding and occasionally curtailing PV production implies inefficiency, "wasted" energy, and lost revenues.

A common current thinking is that these "problems" should be avoided by developing strategies that will "minimize curtailment and grid upgrades" (Candelise and Westacott, 2017). The first response has been to size discrete solar generation systems at a level to minimize capacity investment and avoid generation that is excess to local load. Net metering rates often further incentivize solar system undersizing by providing substantially lower compensation rates for "excess" generation. Because solar investment decisions have also been limited by relatively high capital costs, the result has been suboptimal system sizing and resulting economic waste in a world of rapidly falling solar capacity costs.

Other strategies often rely on electrical storage as their main implementing vector (Pierpoint, 2017, Zahedi, 2011). As solar PV capacity costs continue to fall, PV oversizing/curtailment offers a cost-effective alternative to energy storage costs, especially at the distributed scale. As we'll demonstrate in this paper, an optimum strategy for high solar PV penetration must include oversizing/curtailment as a major element of firm solar power delivery. It is important to note that the proactive curtailment we discuss here differs from its common current implementation and conceptualization, which typically sees reactive curtailment on a capacity basis to manage transmission congestion, emergency, or minimum generation events (Rogers et al., 2010). Frequently overlooked is the opportunity to pursue proactive energy-based curtailment coupled with the oversizing of generation resources in tandem with storage in order to firmly meet load. This opportunity is the focus of the analysis reported in this article.

3. Optimum oversizing & dynamic curtailment

Compared to unconstrained (i.e., business-as-usual) PV, oversized and proactively curtailed PV produces the same quantity of electrical energy over a given time period, but its intermittency is considerably reduced by minimizing production shortfall gaps.

In Appendix A, we provide a simplified example contrasting storage-alone and overbuilding/curtailment/storage strategies to deliver firm baseload generation. This simplified example shows that, given expected costs for PV and storage, the increased cost of PV oversizing and losses of curtailed production can be more than offset by the reductions in storage cost to achieve firm production.

Appendix A example describes a simplified strategy to curtail daily production across-the-board. In the real world, operators should apply a dynamic curtailment strategy responsive to battery state of charge in relation to solar supply and load demand. The algorithm developed by Perez (2014) recursively scans, PV output, load demand and storage status, and dynamically curtails PV when (1) storage reserves are full and (2) load demand is smaller than PV output – see logic diagram in Fig. 2.

Optimizing storage size and oversizing PV to achieve lowest-cost firm power net generation is realized by analyzing long-term time series of time-coincident PV generation and demand. We apply a nested Brent optimization approach for this minimum cost optimization (Brent, 1973). The optimization is a function of the relative capital cost (CapEx) and operational costs (OpEx) of PV and storage, as well as of the PV resource in relation to the firm load requirements. On a duty-cycle scale, firm load requirements can range from light duty–e.g., firmly meeting hour-ahead or day-ahead PV production forecasts–to heavy duty – e.g., meeting a 24/7 baseload year-around.

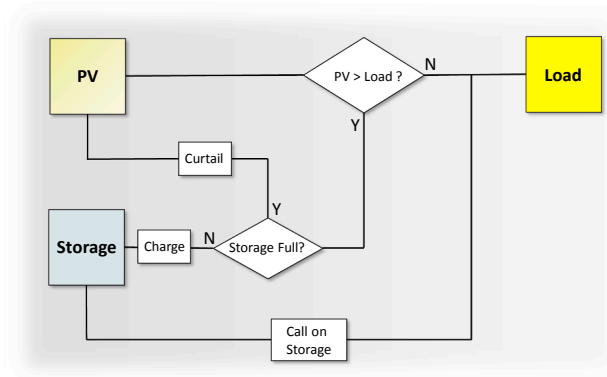

Fig. 2. Dynamic Curtailment Logic Diagram (Perez, 2014).

We illustrates optimization results from a recent study in the State of Minnesota (MDC, 2018; Perez et al., 2018a)

The firm power duty cycle considered for this optimization is for a single utility-scale PV plant located near the state's capital city to firmly meet a load proportional to the regional Transmission System Operator (TSO) load. Ten years worth' of hourly load data were analyzed.

Hourly PV plant production for the same 10 years was simulated from high-resolution site and time-specific irradiance data from SolarAnywhere (SolarAnywhere, 2018, Perez et al., 2002) assuming south-facing 30°-tilt geometry for PV and assuming crystalline silicon technology. We applied SolarAnywhere's internal PV simulation engine that is built on the PVFORM algorithm (Menicucci and Fernandez, 1988, Perez et al., 1994) that also served as a basis for NREL's PVWatts (NREL, 2018). The industry-accepted accuracy (bias) for these simulations is ± 5% (e.g., SolarGIS, 2018). This level of uncertainty should translate linearly to the levelized energy costs presented below.

In Fig. 3, the firm kWh premium resulting from this simulation is plotted as a function of the amount of PV curtailed[1] assuming the following long-term (2050) storage and PV CapEx projections issued by NREL for utility-scale applications (NREL, 2016):

- PV = $400/kW; storage $100/kWh–utility-scale PV long term optimistic (NREL, 2016)
- PV = $700/kW; storage $300/kWh–utility-scale PV long-term conservative (NREL, 2016)

The OpEx for PV is set at 1% of CapEx per year. For the battery storage, this value is 0.02% per full discharge cycle (Tesla, 2018).

For both economic scenarios, the firm generation premium achieved with optimal dynamic curtailment is considerably smaller than the storage-alone premium (i.e., at 0% curtailment). For this single power plant configuration, optimum curtailment levels of respectively 82% and 74% reduce firm kWh premiums from over 100 to 9 and from 64 to 7 for the long-term conservative and optimistic cost scenarios. These curtailment levels correspond to PV generation oversizing of respectively 5.7 and 3.8.

The firm kWh premiums reported in Fig. 3 can be expressed in levelized cost of energy ("LCOE") terms using appropriate life cycle cost assumptions. For illustrative purposes, we applied the financial assumptions selected by utility, government, and industry stakeholders for the USDOE Minnesota Solar Pathways study (MDC, 2018; Perez et al., 2018a) shown in Table 1. Firm and unconstrained (i.e.,

[1] Note that the PV oversizing ratio is the inverse of the uncurtailed PV fraction (e.g., 75% curtailment requires oversizing a system by 4 to produce a given amount of electricity).

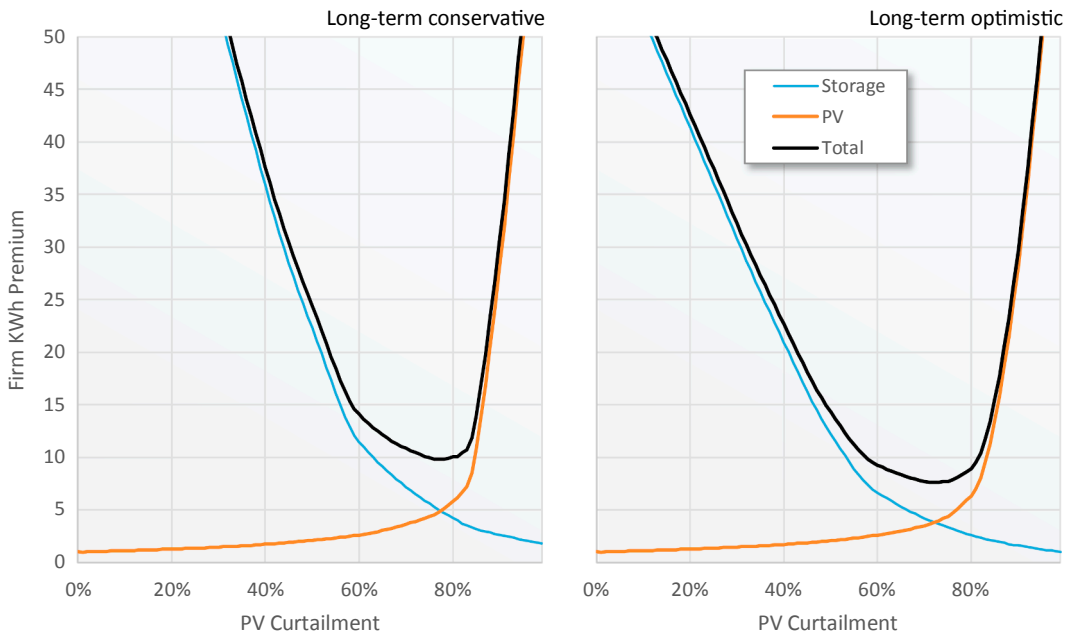

Fig. 3. Single-plant firm kWh premium in Minnesota as a function of PV dynamic curtailment for long-term conservative (left) and long-term optimistic (right) PV and storage cost assumptions. The red and blue lines respectively represent the contributions of PV and storage to the total premium (black line). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 1
Lifecycle cost assumptions.

Utility WACC[1]	3%
Lifecycle	30 years
O&M PV	1%
O&M storage	0.1% per cycle

[1] A WACC (Weighted Average Cost of Capital) of 3% is a value representative of the utility industry (NYU Stern School of Business, 2018). For information a 2% increase in assumed WACC would result in a 15–20% increase in LCOEs all other conditions equal.

intermittent) PV LCOE under these financial assumptions are reported in Table 2 (first two rows, single-location). It is important to note that these LCOE production costs do not embed any direct or indirect incentives, tax effects, or externality provisions (e.g., such as tax credits, deductions, depreciation, RECs, or rebates).

The results in Table 2 demonstrate that while unconstrained PV production costs will reach very low targets–well below the often quoted, "grid parity" threshold, delivering firm, "high-penetration-ready" electricity, i.e., achieving *real grid parity,* is considerably more expensive. Achieving real grid parity would be economically unacceptable using storage-only solutions. The results also show that

Table 2
Comparing unconstrained and firm PV LCOEs for a single plant, intra-state dispersed generation, with addition of 5% gas, and with optimal wind power blending.

	Single location PV generation		
	Unconstrained PV kWh	Firm PV kWh without curtailment	Firm PV kWh with optimal dynamic curtailment
Long-term utility scale conservative	$0.024	$2.575	$0.211
Long-term utility scale optimistic	$0.014	$0.864	$0.099
	Statewide distributed PV generation		
	Unconstrained PV KWh	Firm PV kWh without curtailment	Firm PV kWh with optimal dynamic curtailment
Long-term utility scale conservative	$0.023	$2.460	$0.145
Long-term utility scale optimistic	$0.013	$0.826	$0.066
	Statewide distributed PV generation with 5% natural gas		
	Unconstrained PV KWh	Firm PV kWh without curtailment	Firm PV kWh with optimal dynamic curtailment
Long-term utility scale conservative	$0.023	$1.892	$0.097
Long-term utility scale optimistic	$0.013	$0.641	$0.048
	Statewide distributed PV and wind generation mix		
	Unconstrained PV/Wind kWh	Firm PV/Wind kWh without curtailment	Firm PV/Wind kWh with optimal dynamic curtailment
Long-term utility scale optimistic w/o natural gas	$0.023	$0.397	$0.051
Long-term utility scale optimistic with 5% natural gas	$0.014	$0.284	$0.035

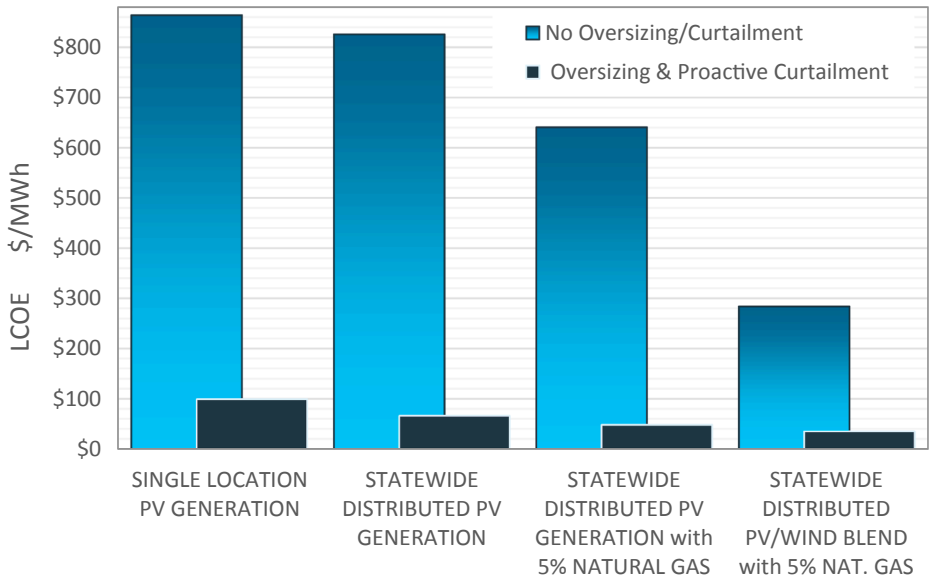

Fig. 4. Illustrating the LCOE impact of overbuilding/curtailment to firmly meet Statewide MISO load 365/24/7.

overbuilding PV and dynamically curtailing production could produce firm generation costs that are considerably closer to acceptability. This oversizing/proactive curtailment "effect" is illustrated in Fig. 4 where the LCOEs reported in Table 2 with, and without operational curtailment are graphically contrasted for the long-term utility-scale optimistic scenario.

4. Achievable lowest-cost firm generation

Dynamic output curtailment and overbuilding, however counter-intuitive to conventional electricity system planners, can yield significant cost reductions for achieving firm generation value compared to storage-only solutions. In addition to curtailment/oversizing, two complementary solutions and strategies can further reduce the firm kWh premium: geographic dispersion and load flexibility. Furthermore, adding wind resources (or other complementary clean generation[2]) can exploit the uncorrelated nature of different types of variable generation and achieve even lower firm electricity generation costs.

Geographic Dispersion: Geographic dispersion mitigates generation variability, even within a single kind of generation. This saves money on intermittency mitigation requirements, and extension, firm kWh premiums by exploiting the well-documented and quantified weather-smoothing effect (Perez et al., 2016a, 2016b; Hoff and Perez, 2012; Mills and Wiser, 2010). The larger the footprint of an integrated grid, the longer the time-scale of variability that can be reduced or eliminated via resource dispersion. For example, one-minute fluctuations can disappear if the PV generating facilities are evenly distributed over a few kilometers. Hourly variability disappears with a multi-facility footprint of a few hundred kilometers. Daily variability can be effectively mitigated if the facilities are distributed across a footprint of a few thousand kilometers (Perez et al., 2016b). This strategy has costs reflected in the capital and operating expenses necessary to enable and manage regional transfers of solar-generated electricity, i.e., larger conductors, multiple transmission pathways, and more intensive management of multi-directional energy flows (Bloom et al., 2016). The Minnesota-based study evaluated a PV generation dispersed within Minnesota proportionally to the state's population density and deployed near existing transmission pathways. By leveraging the capacity of existing transmission configurations, this geographical distribution did not require any significant strengthening of the transmission grid (MDC, 2018; Perez et al., 2018a). Note that previous work by Perez (2015) has shown that grid strengthening costs for regional firm power generation remained relatively small compared to storage and oversizing even assuming worst case saturated grid initial conditions.

Enlarging the PV generating footprint within the state results in optimal firm premium reduction of ~35% compared to a single PV plant. Optimal oversizing requirements are also reduced to 3.3 and 2.9 for the conservative and optimistic technology cost scenarios respectively. Results are shown in Fig. 5 for the same economic assumptions and load duty cycle requirements as Fig. 3. Corresponding electricity unconstrained and firm generation LCOEs are reported in Table 2 (dispersed PV generation).

Load Flexibility: Load flexibility describes a strategy of modulating load to better match PV generation patterns. The PV-targeted duty cycle load can be modulated both on the demand- and supply-side to mitigate PV supply gaps and therefore reduce storage requirements.

On the demand side, strategies that can shape demand in response to PV supply include thermal strategies such as [pre]cooling and heating (e.g., Hoff, 2016), electrical transportation strategies (e.g., via vehicle charging optimization), industrial and commercial tasks scheduling, and other demand and distribution system management techniques. Operationally, demand-side load shaping is somewhat analogous to storage: i.e., increasing load when the solar resource is plentiful (charging) and reducing it when it is not (discharging). Demand-side load shaping differs from storage in one fundamental way: the cost of load shaping is unlikely to be linearly proportional to the degree to which it is implemented. Indeed, whereas the cost of (battery) storage is a defined constant in terms of energy reserve capacity (e.g., $100/kWh), the cost of load shaping increases with reserve capacity requirements. This is because while a small amount of demand flexibility is inexpensive, incremental amounts of flexibility become gradually more expensive as strategies and customer responses become increasingly burdened, reaching asymptotically expensive points of inoperability and unacceptability.

On the supply side, the PV-targeted load can be modulated using dispatchable conventional generation to make up for critical PV resource deficits. The cost of the supply-side approach to load flexibility is directly quantifiable, since the technology and fuel costs are known. In Fig. 6, we illustrate the impact of "buying" load flexibility by allowing a maximum of 5% annual energy contribution from natural gas. In this

[2] These resources could include electricity generated by super-efficient combined heat and power facilities that operate to serve thermal load as a priority, biomass energy, and tidal and wave generation).

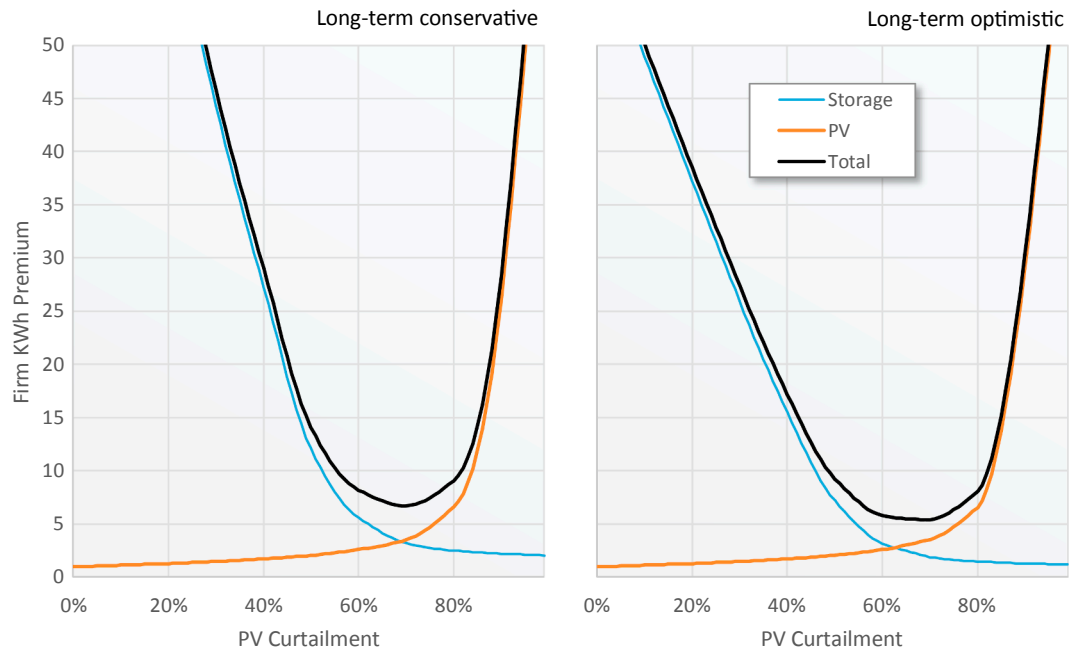

Fig. 5. Geographically distributed PV firm kWh premium in Minnesota as a function of PV dynamic curtailment for long-term conservative (left) and long-term optimistic (right) PV and storage cost assumptions. The red and blue lines respectively represent the contributions of PV and storage to the total premium (black line). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

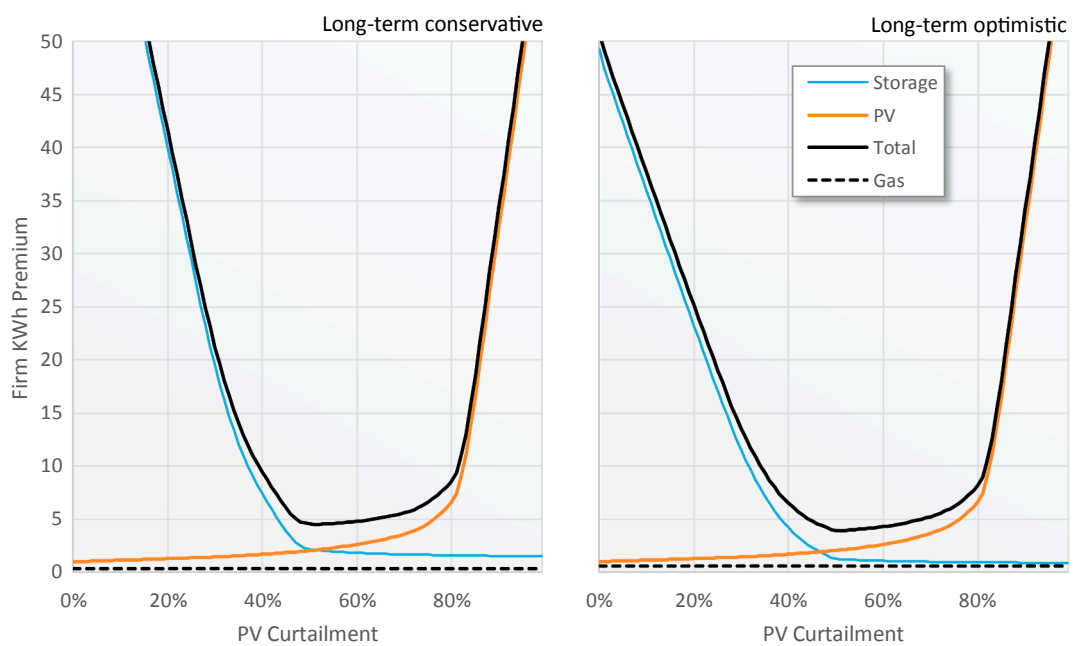

Fig. 6. Firm kWh premium for distributed PV generation in Minnesota allowing for a maximum of 5% natural gas as a function of PV dynamic curtailment for long-term conservative (left) and long-term optimistic (right) PV and storage cost assumptions. The red and blue lines respectively represent the contributions of PV and storage to the total premium (black line). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

example, we further assume that the existing gas generation infrastructure that would be otherwise displaced by firm PV generation can be utilized, i.e., we only consider operational costs for gas.

Results show that a 5% natural gas allowance leads to a major reduction in PV oversizing to achieve lowest cost firm electricity production. This is because worst-case intermittencies can be addressed by natural gas power generation. While storage only-solutions remain prohibitively expensive (Table 2 – 5% Gas), firm optimized electricity production LCOE for a 95% dispersed PV resource can be expected to be less than 5 cents per kWh, i.e., in a range comparable to the current regional bulk electrical energy cost (EIA, 2018).

We note that, operationally, the management of these optimized storage and natural gas resources, once properly sized to minimize LCOEs, would benefit from high quality short-term forecasts (< 24 h) to optimize charge/discharges so as to minimize wear and tear (hence reduce O&Ms) and to anticipate calls for natural gas.

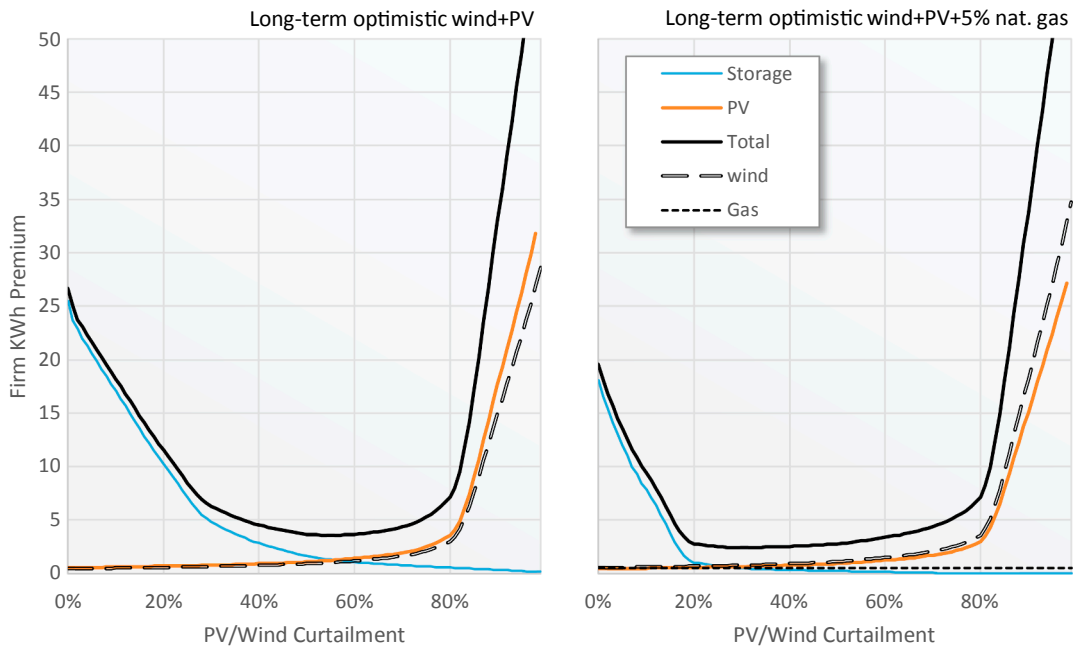

Fig. 7. Firm kWh premium for optimum PV and wind generation mix assuming long term optimistic cost assumptions without natural gas (left) and with a maximum 5% natural gas contribution (right).

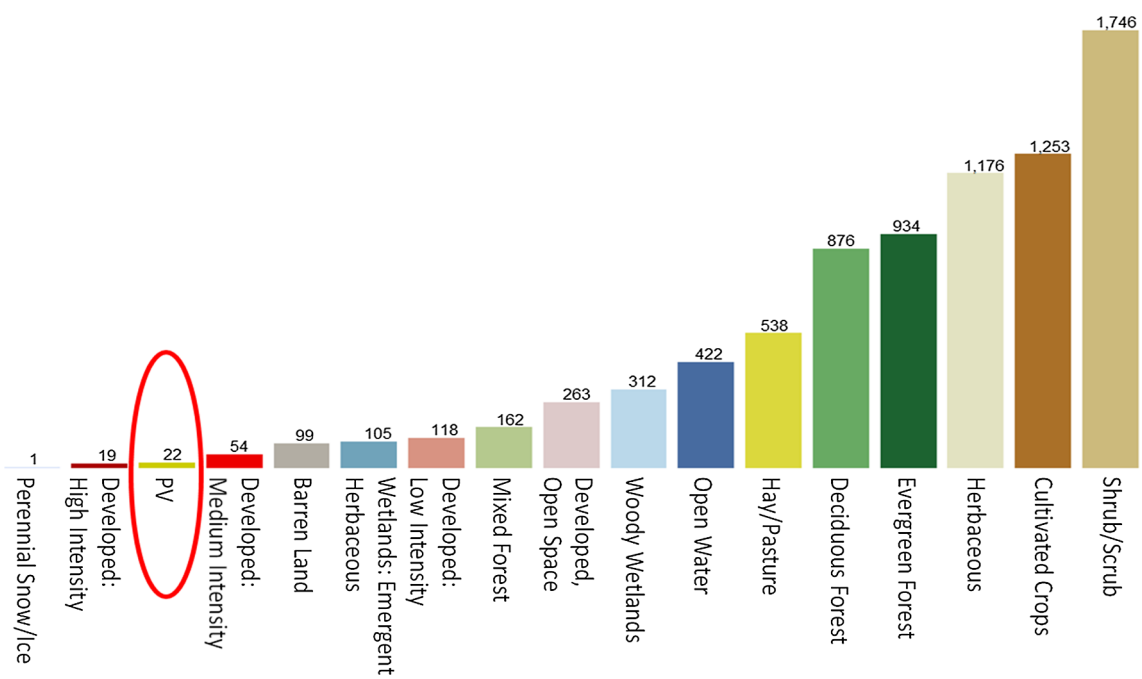

Fig. 8. Contrasting the area required for 100% firm PV generation in the US (including 200% resource oversizing) to the country's land cover (10^3 km^2) – MRLC (2011).

Wind and PV Generation Blending: Like solar, wind power is clean but variable. It can also be firmed using a combination of the same PV-firming strategies presented above. While the global potential for wind is smaller than that of solar (Perez and Perez, 2015), this potential is nevertheless vast, both inland and offshore. Like PV, wind electricity production costs have achieved very low targets on a pure energy basis.

Integrating the management of wind and solar generation results in firm electricity costs that are lower than either technology could achieve separately (e.g., Jacobson et al., 2015; Perez et al., 2012). This is because wind and solar generation variations are largely uncorrelated on multiple time scales–intraday, day-to-day, and seasonal. Mixing uncorrelated variable resources inherently reduces variability (Perez et al., 2016b), much like the underlying driver of the spatial smoothing effect. A newly released article by Shaner, et al. (2017) makes it clear that co-managing solar and wind generation and allowing for curtailment can be demonstrably cost and performance effective. Because the cost premium to transform variable into firm electricity is a direct function of the resource's native variability, a less variable solar-wind

mix should result in a lower firm kWh premium.

In Fig. 7 we illustrate the impact of optimally combining wind and solar for the same Minnesota case study previously discussed. We present long-term utility scale optimistic scenarios as defined above for PV, and $1070/kW CaPEx and 1%/OpEx for wind (NREL, 2016). We show results with and without supply-side flexibility from natural gas. Statewide hourly wind generation production time series coincident to PV and load were extrapolated from the actual production of 70 major wind in-state wind farms (MDC, 2018). We applied the same dynamic curtailment algorithm to the wind and PV mix as above, with an additional optimization loop to determine the optimum, lowest-cost mix. This secondary optimization points to a 40% wind and 60% solar blend, based on the considered resources' long-term capital and operational costs and the in-state solar and wind resource characteristics.

The intermittency mitigation synergy between solar and wind acts to reduce the solar-only firm electricity LCOEs by 25%, with oversizing requirements of only 35–40% in the 5% gas scenario. The achievable solar and wind firm production cost, with a 5% gas contribution, could be reduced to 3.5 cents per kWh (Table 2 – wind PV mix). This value is below the mean 2017 regional (MISO) wholesale energy market price of 3.67 per kWh (EIA, 2018). In addition, since firm power generation implies full capacity credit by definition, the achievable 3.5 cents should be compared to not only the regional wholesale energy price, but also to the additional capacity market price prorated per kWh generated. This analysis does not include environmental externalities that would further increase the comparison threshold.

5. Discussion: implications for PV remuneration & deployment

PV electricity remuneration: The examples we presented for a northern US state with a relatively modest solar resource strongly suggest that very-high (95%) intermittent RE (wind/PV) penetration with 365/24/7 firm capacity guaranties could be accomplished at production costs below current conventional generation. However, this potential may not be achievable with existing solar electricity remuneration frameworks. The current, predominant systems for remunerating solar electricity in the US and many other countries are effectively *marginal* systems. Solar electricity is valued at the margin against costs that it displaces: retail rates in the case of net energy metering (NEM) and self-consumption, energy and capacity market rates as well as deferred grid upgrade costs in the case of the emerging Value-Of-Distributed-Energy-Resources (VDER) tariffs proposed in some US states (NYSPSC, 2016). These marginal systems, that remunerate unconstrained PV kWh, are suitable as long as PV remains a marginal resource. They will become unsustainable and will lead to unproductive reactive curtailment (forced by negative pricing) when intermittent RE penetration augments and becomes a dominant grid resource. This is because current marginal valuation inherently does not account for the cost of producing firm power, including the cost of the technologies and operational strategies to transform variable electricity into effectively dispatchable electricity. Feed-in tariffs that are still in effect in some countries, but at considerably reduced levels, and often morphed into marginal pricing systems via promotion of self-consumption (Germany France, Wirth, 2017) may have more adaptability to capture PV's firm generation potential and serve PV growth than the marginal systems. Although feed-in tariffs have rarely been optimally calibrated and have often led to boom/bust cycles (Cox and Esterly, 2016), they were devised to reflect the cost of [initially very expensive] solar and to provide acceptable returns on investment. We posit that the remuneration system that will grow PV and capture its lowest-cost high-penetration potential is a system that will reflect the cost of producing firm solar electricity, i.e., including all the embedded strategies and technologies to transform intermittency into firm capacity—in particular, overbuilding, curtailment and storage. Importantly, continuing with current marginal remuneration strategies not accounting for firm generation, will, as RE penetration grows, increase the burden and diminish the value of future RE systems that will have to deliver firmness while grandfathering a (growing) base of unconstrained RE systems (MDC, 2018).

PV Deployment: Lowest-cost PV with firm production guarantees entails the following challenges: (1) deploying lowest-cost PV plants; (2) optimally locating these plants; (3) optimally deploying PV-firming infrastructure and strategies, in particular overbuilding, storage, grid upgrades and load flexibility; (4) optimally managing solar flows on the power grid, i.e., managing optimal curtailment, storage and demand-side resources.

These challenges suggest that the bulk of new PV systems should be utility-scale and, more importantly, utility-managed. Does this imply the end of the current [marginal] demand-side customer ownership/leasing/PPA PV deployment paradigm? It does not have to, but the current deployment system will have to evolve.

- Customer ownership could be scaled-up to the utility level via community solar ownership models.
- Smaller DG units should remain on customers' premises for high value trade-offs: in particular for resiliency purposes (micro-grid capability), but also for taking full advantage of effective demand-side load management synergies. Ideally, remuneration for DG units should reflect firm power generation fundamentals and enable grid-operator control.

In any case, the results presented in this paper indicate that management of PV electricity and siting decisions for the bulk of PV installations would be most optimally implemented by grid operators.

Another important question relative to PV deployment is the impact of optimal oversizing on the space occupied by PV. The answer to this question, however trivial and obvious to some, is important to state because decision makers who are not always fully informed often raise the issue of space.

In most of the USA, oversizing PV by a factor of less than two could cost-optimally deliver the firm power generation guaranties necessary for a PV-dominant grid. How much space would an oversized PV resource occupy? Estimating the answer in the most extreme (100% PV, 100% penetration) case is informative. Roughly 4500 GW of PV would be required to produce enough PV electricity after curtailment to optimally deliver lowest-cost, firm, 100% solar electricity in the US. This is a very large number, but not unreasonably so. 4500 GW "only" represent 50 years' worth of the 2017 global annual PV manufacturing capacity – a manufacturing capacity that has grown over one hundred-fold from 2002 to 2017 (Wikipedia, 2017) – i.e., if manufacturing capacity increases by another 100-fold over the next 15 years, this 4500 GW would represent only half of the global PV manufacturing capacity at that date.

In terms of ground occupancy, it is informative to contrast this dispersed 4500 GW PV footprint with examples where space is already occupied for industrial/energy purposes that could be used, albeit in part, to deploy PV. For instance, US high-voltage power line rights-of-way alone could accommodate nearly 1500 PV GW. Another example is hydropower that produce only 6% of the US electricity but whose artificial reservoirs span an area large enough to accommodate over 6000 GW's worth of PV (Perez et al., 2018b). These two examples, among others, suggest that even in an extreme 100% PV penetration scenario with over 50% output curtailment, the PV footprint would remain acceptable, especially if one considers that urbanized spaces including rooftops, parking lots, and roadways could be intelligently applied to support a substantial fraction of PV deployment. To put this in quantifiable visual perspective, we compare the area a 100% optimally oversized firm PV generation scenario would require in the US to

the country's land cover distribution in Fig. 8.

Curtailed PV Electricity: The firm power generation, high penetration-ready LCOEs presented in this paper assume that curtailed energy is completely unused, i.e., value-less. It is nevertheless possible to point out that new markets could emerge to take advantage of this virtually free, but highly variable excess electricity, hence augment the value propositions discussed above. Target applications would be applications with low capital costs, high operational energy requirements, and no time constraints: two possible example would be low-tech forms of desalinization and hydrogen production.

6. Conclusions

Solar PV is rapidly becoming one of the least expensive electricity generation resources. However, the cost of transforming intermittent solar energy into firm, on-demand electricity can be considerable. Firm electricity is a prerequisite to high penetration.

Embracing overbuilding and strategic curtailment is central to reducing the cost of firm PV generation. We showed that this strategy was central to achieving lowest-cost, firm, on-demand electricity, implying that a solar-dominant power grid could operate at an average electricity production cost directly comparable to today's conventional generation, even before consideration of any external [environmental] costs.

We have argued that the marginal PV remuneration systems in place today may not be ideal to foster this lowest cost solar potential, and that solutions need to be explored and policies developed that center on valuing firm kWh production and on enabling effective solutions and strategies that can deliver lowest-cost firm renewable electricity, in particular enabling overbuilding and curtailment.

We also argued that, (1) whereas a solar-only solution would be realistic, exploring solar and wind solutions will deliver lower operational costs and lead to cheaper firm renewable electricity and (2) allowing a minimal amount of natural gas could bring these costs down further considerably.

Finally, it is important to state that, while we only looked at one single [northern] US state, the present results are fully consistent with earlier preliminary continental-scale investigations (Perez, 2014). It will nevertheless be worthwhile to investigate other case studies in detail where optimum solutions would evolve to reflect localized renewable resources' characteristics. The authors are currently engaged in several such investigations – particularly in non-interconnected island power grids – that will be the subject of future communications.

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Appendix A. Curtailment vs. energy storage – a simplified illustration

The potential benefits of intentional overbuilding and curtailment for PV generation are illustrated through a simplified example contrasting two PV intermittency mitigation strategies: (1) a strategy using storage alone, and (2) a strategy applying storage, PV overbuilding, and curtailment. Both strategies assume the objective of meeting a firm, 24/7 flat load with PV in the northeastern United States (i.e., the type of load served by so-called "base-load" nuclear generators). Both strategies can achieve this objective, but at different costs. The following economic specifications for PV and storage, plausibly achievable in the foreseeable future, are used to illustrate this example:

- PV cost \$1,000 per kw_{ac} turnkey (Munsell, 2017).
- Storage cost: \$100 per kWh[3] of energy storage reserve capacity (Wesoff, 2016)

In this simplified example, we apply curtailment across-the-board above a given daily PV output threshold. Fig. A1 contrasts uncurtailed PV (top) and 3X oversized/curtailed PV (bottom) to meet the 365/24/7 base load target (shown in light blue). Both uncurtailed and oversized/curtailed PV produce the same amount of energy – i.e., enough energy to meet annual load requirements on a yearly basis.

Comparing the time series of uncurtailed and oversized/curtailed PV shows that both daily and seasonal intermittencies are considerably reduced for the latter. Whereas both strategies require storage to meet demand-supply gaps (including nighttime gaps), the oversized/curtailment strategy requires much less storage. In this simplified example, uncurtailed PV would require 170 PV peak hours' worth of storage[4] to meet the specified 24/7 flat load at all times. From the above cost assumptions, the cost of removing intermittency by storage alone thus increases the cost of unconstrained PV by 1800%. This implies that a firm PV kWh is 18 times more expensive than an unmanaged, intermittent PV kWh if the solution to deliver firmness is storage alone. This also implies that, even if PV cost dropped to zero, the cost of a firm, baseload kWh would remain unrealistically high because of the required quantity and cost of storage.

Even unoptimized oversizing and across-the-board curtailment of PV, as shown in this example, reduces storage requirements by a factor of six. This is because the intermittency gaps of oversized/curtailed PV are considerably smaller than those of unconstrained PV (these intermittency gaps occur when the oversized/curtailed PV production falls below demand). As a result, oversizing PV threefold reduces PV-plus-storage costs by a factor of three, even after accounting for the extra cost of PV.

[3] A common misinterpretation is to assume that this number is the cost per kWh of energy from the battery. It is not. It represents the nominal CapEx of the battery per unit of storage capacity. For instance, a battery capable of storing 10 kWh of electrical energy that costs \$5000 has a nominal CapEx of \$500/kWh.

[4] A peak hour worth of storage is defined as the required storage reserve capacity (kWh) divided by the peak rating of the considered PV plant – e.g., for a 10 kW PV plant, a 25 kWh storage system represents 2.5 peak hours.

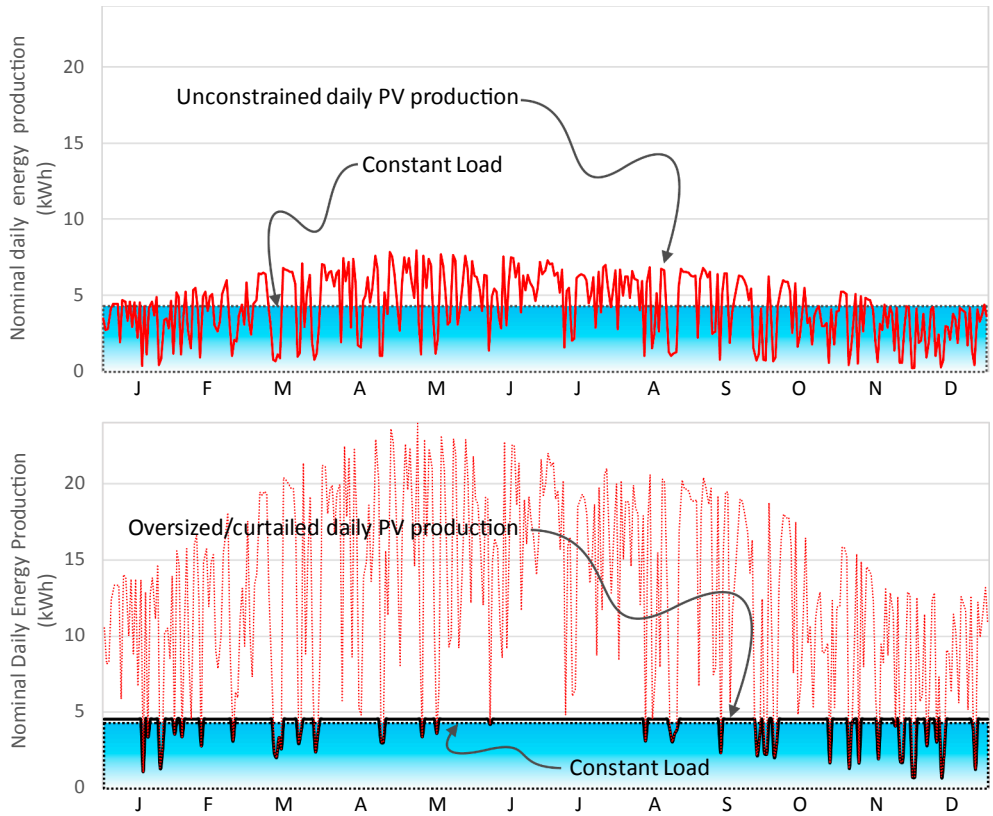

Fig. A1. Comparing unconstrained and 3X oversized/curtailed daily PV output relative to baseload requirements for a period of one year.

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