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Evaluating the limits of solar photovoltaics (PV) in traditional electric power systems

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Abstract

In this work, we examine some of the limits to large-scale deployment of solar photovoltaics (PV) in traditional electric power systems. Specifically, we evaluate the ability of PV to provide a large fraction (up to 50%) of a utility system's energy by comparing hourly output of a simulated large PV system to the amount of electricity actually usable. The simulations use hourly recorded solar insolation and load data for Texas in the year 2000 and consider the constraints of traditional electricity generation plants to reduce output and accommodate intermittent PV generation. We find that under high penetration levels and existing grid-operation procedures and rules, the system will have excess PV generation during certain periods of the year. Several metrics are developed to examine this excess PV generation and resulting costs as a function of PV penetration at different levels of system flexibility. The limited flexibility of base load generators produces increasingly large amounts of unusable PV generation when PV provides perhaps 10–20% of a system's energy. Measures to increase PV penetration beyond this range will be discussed and quantified in a follow-up analysis.

Keywords: Solar; Photovoltaics; Intermittency

1. Introduction

Solar photovoltaics (PV) currently represent a very small share of electricity capacity and production. For example, in the United States, about 500 MW of PV were installed cumulatively through 2005, representing less than 0.1% of the total national electricity generation capacity (PV News, 2006b). However, it is possible that this technology could eventually grow to be a major component of the electricity generation system. During the past decade (1995–2005), the PV industry has been growing rapidly, with an average annual growth rate of 37% worldwide (PV News, 2006a).

If the PV industry can achieve cost reductions in-line with industry and United States DOE targets (US DOE, 2006) during the next decade, then PV could become widely cost-competitive in the United States, i.e. at or below the current retail cost of electricity for many customers, particularly in places with high electricity prices and good solar resources such as California. If the cost of PV is substantially below the retail price of electricity, it can be expected that many consumers would choose to install PV to reduce use of higher cost utility electricity.

Rapid growth and transition has occurred previously for new, capital-intensive technologies in the electric power sector. In the 15-year period between 1972 and 1987, more than 85 GW of new nuclear generation was constructed in the United States, with more than 5 GW per year constructed during 9 of those 15 years (EIA, 2005a). During this time period, the fraction of United States generation provided by nuclear energy grew from about 3–18%. This growth rate indicates that a transition to an electric power system that is heavily reliant on new technologies—such as PV—could occur within the next couple of decades.

In the longer term, solar PV (and other solar energy technologies) is among the few sources of energy that are universally deployable and sustainable. The technical potential of the grid-connected solar PV market in the

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United States is enormous—more than 500 GW in rooftop applications (Chaudhari et al., 2004), or many TW including ground-based systems (Zweibel, 2005). Not only does PV have a larger technical potential than any other renewable energy technology, it also is not as geographically constrained as other renewables. In theory, PV has the technical potential to supply all of the electricity demand in the United States, and to virtually eliminate carbon emissions from the electric power sector.

The intermittency of solar energy, however, presents critical challenges in integrating large-scale PV into the electricity grid. This intermittency ultimately may limit the potential contribution of PV to the electricity sector. Current grid systems can reliably and economically use a single conventional generation source to produce the bulk of their electricity (EIA, 2005b). Many regions currently use fossil or nuclear plants to provide more than 50% of their electricity. Intermittent sources of electricity such as wind and solar are expected to have technical and economic limitations in reaching this level of penetration (Denholm et al., 2005). While there has been some analysis of the potential impacts of wind on large electric power systems at high penetration (Parsons et al., 2006; Buckley et al., 2005), we are not aware of a significant body of work analyzing solar PV at high penetration. Considering the vast solar resource, the desire for more sustainable electricity generation systems, and continued cost decreases of solar PV generation, it is worth examining some of the possible limits on grid penetration of this emerging generation source.

In this paper, we examine some of the challenges faced by extremely large-scale deployment of PV, using results of a case study to show potential impacts of PV in a specific conventional electric power system. We begin by examining some general characteristics of both electric power systems and solar PV systems including typical electric demand patterns at different times of the year, the typical mix of generator types and resulting limits on system flexibility, and the daily and seasonal variation of PV system output. We then provide a description of a tool (PVflex) that we developed to evaluate the interaction between solar PV and utility systems, considering the limitations of the flexibility of traditional electric generators. Finally, we provide results of a simulation of the Electric Reliability Council of Texas (ERCOT) electric system. The simulations demonstrate the potential usefulness and cost impacts on PV when attempting to provide up to 50% of the system's electricity from that resource.

Our emphasis here is on how large-scale deployment of PV would interact with the existing electricity infrastructure. In a subsequent paper, we examine the potential to increase PV penetration beyond the limits discussed here—in particular, by changing the system's operation or configuration, or deploying "enabling" technologies designed to more effectively utilize electricity generated from intermittent sources such as solar PV (Denholm and Margolis, Forthcoming).

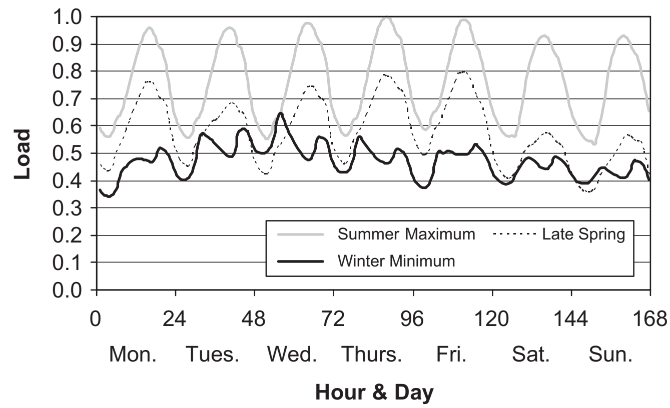

Fig. 1. Normalized seasonal load patterns for ERCOT (three weeks in 2000).

2. Possible impacts of PV on the electric power system

Electric power systems are designed to respond to the aggregated instantaneous electricity demand of a large number of diverse consumers. Electricity demand is a function of time of day, weather, season, business cycles, etc., and there is considerable variation in both the amount of electricity used, and the "shape" of electricity loads over time. Fig. 1 includes a set of weekly load patterns for the Electric Reliability Council of Texas (ERCOT) system at three different times of the year as recorded in 2000 (Electric Reliability Council of Texas (ERCOT), 2005).[1] For the discussion here, the relative variation in loads throughout the day and over seasons is more important than the actual amount of load so we have normalized the load to the annual peak. As shown in the figure, a load value of 1 is equal to the annual peak load, or the load during the hour with the highest demand.

While the demand patterns in Fig. 1 are for a specific region of the United States, many of the general trends shown in the demand patterns are common throughout the country (Federal Energy Regulatory Commission, 2005). Annual peak demand is typically driven by summertime air conditioning loads, with a peak around 3–4 p.m. local time. Winters typically show a double peak from morning activities and an evening lighting load. Demand is also noticeably reduced during weekend days. The yearly minimum typically occurs in the early morning (about 3–4 a.m.), during the season with the mildest temperature, i.e. during the spring or fall for much of the United States. In this particular location and year, the minimum occurred during the winter.

Additional insight into electricity use and power system operation can be gained by reordering the annual demand data into a load duration curve (LDC). A LDC indicates the total number of hours a system is required to provide a

[1]Hourly load from the ERCOT system in 2000 (used for this and all subsequent figures) was derived from FERC. The data was adjusted to account for daylight savings time.

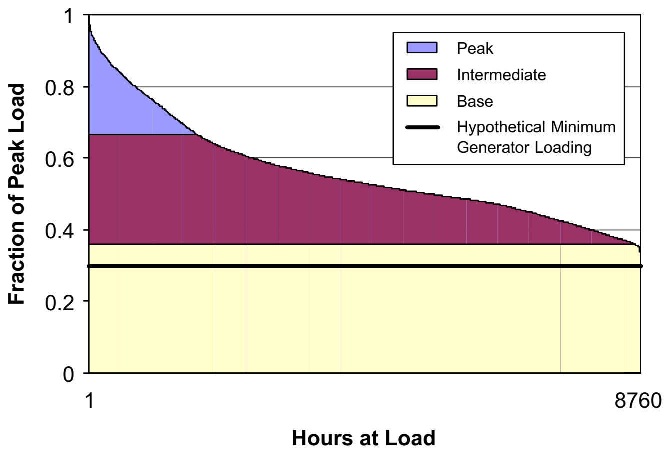

Fig. 2. Normalized load duration curve for ERCOT (2000).

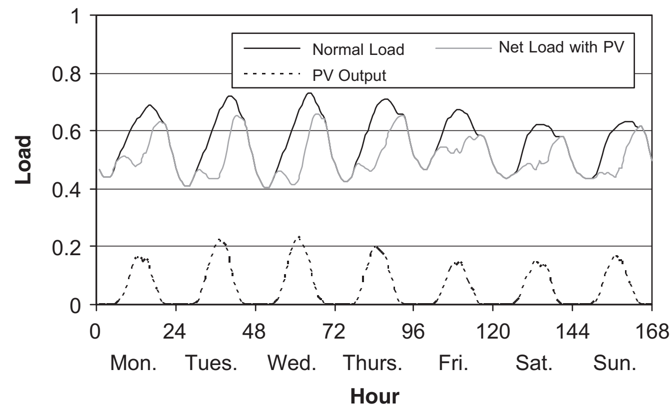

Fig. 3. Coincidence of PV generation and demand in ERCOT during a week in June 2000.

given amount of load. Fig. 2 provides a LDC for ERCOT during 2000. As before, the total power is normalized to the peak load.

While Fig. 2 is for Texas in 2000, the shape of load duration curves for the United States are quite similar from region to region (Federal Energy Regulatory Commission, 2006). For planning purposes, there are three loosely defined regions on this curve. As shown in Fig. 2, these regions include: base load, intermediate load, and peaking load.

Base load plants are used to "fill" most of the bottom half of the load duration curve. They are designed for continuous operation with low operating costs, making them well suited for this role. In much of the United States, base load plants are steam plants fired by coal or nuclear energy (EIA, 2005a). Many of these large base load plants have limited ability to "cycle" or vary output. In the typical configuration and operation modes of existing electricity generation systems, this is not a problem since the majority of the energy under the LDC curve can be provided by plants that either do not cycle, or cycle very little.

Included in Fig. 2 is a line indicating a hypothetical minimum generator loading condition. This line represents the minimum level to which conventional generators can be "turned down" with minimal economic penalty. If the load drops below this level, one or more base load plants would likely be required to completely shut down for a short period of time, which would incur significant economic penalties. Nuclear plants are particularly limited by long ramp rates and limited ability to reduce output for short periods of time. Coal plants are more flexible, but still have minimum loading constraints, due to flame stability and lower limits of power plant ancillary equipment (pulverizers, pumps, etc.). The large daily swings in demand depicted in Fig. 1 are met through the limited economic cycling range of base load plants, plus a large amount of more flexible generators designed for load following duty. These plants include smaller thermal steam plants fired by coal, oil or gas, single or combined cycle gas turbines, and hydroelectric plants. This combination of generators is optimally dispatched to meet the daily load patterns, taking into account the marginal cost of each individual plant, while considering constraints of plant minimum loading, ramp rates, and start-up costs.

It can be expected that Solar PV, particularly at low penetration levels, should fit well into the summertime demand patterns illustrated in Fig. 1. Highest demand periods occur during the day, with the seasonal demand cycle peaking during the summer, which should be correlated with PV output. However, it is not immediately obvious how PV interacts with the overall demand profile as PV achieves increasing levels of penetration, especially during the non-summertime periods when electricity demand is not driven by air conditioning.

Fig. 3 provides an example of the coincidence of PV supply with electricity demand in the ERCOT system. In this example, a simulated PV system has been built to provide 10% of the region's energy demand on an annual energy basis.[2] In this and subsequent figures "net load" refers to the normal electric load minus the solar PV output. During this particular week (June 2000), PV generation provides significant benefits by reducing demand during peak periods.

During other times of the year, however, PV output may be less coincident with demand. Fig. 4 shows the same system and simulated PV output for a week in early March. During this week, we see that the midday demand on the electricity system on the two weekend days is relatively low, while PV output is relatively high.

As shown in Fig. 4, the combination of low system demand and high PV output results in the net system load dropping below 20% of peak load on two days (Tuesday and Wednesday) during the week shown in the figure. In this simulation, it is possible that the system in question will run into significant "minimum loading" conditions on

[2]PV output is the simulated performance of a large spatially diverse PV system using recorded solar insolation data at 9 sites in Texas in 2000. The simulations are discussed in more detail in Section 3.

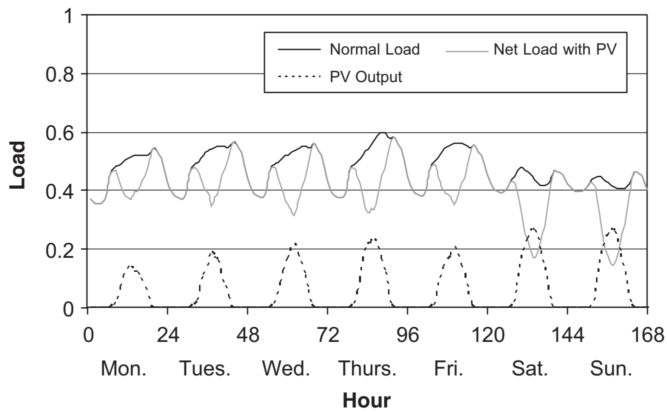

Fig. 4. Coincidence of PV generation and demand in ERCOT during a week in March 2000.

base load coal or nuclear plants during these days. This minimum loading condition is determined by the overall flexibility of the system—the ability of conventional generators to reduce their output without incurring significant economic penalties.

In this paper, we define "system flexibility" as the fraction of peak load below which conventional generators can cycle. A 0% flexible system would be unable to cycle below annual peak load at all, while a 100% flexible system could cycle down to zero load without significant penalties. It should be noted that system flexibility in this work only considers the minimum loading constraint on conventional generation—it does not consider the ramp rates of plants while operating over their normal cycling range. In fact, it may be possible that the conventional plant fleet cannot respond to the potentially rapid ramping of PV output during the morning and evening, as well as fluctuations due to atmospheric conditions such as passing clouds. In this analysis, however, we assume that these types of potential negative effects will be counterbalanced over time by spatial diversity of PV generation, improved forecasting, learning, and load controls. As a result, this study represents an evaluation of the upper bound of solar PV, limited only by the minimum loading constraint.

The minimum loading constraint in a conventional system depends largely on the mix of generation technologies in the system. A system dominated by gas or hydro units will likely have a higher level of flexibility than a system dominated by coal or nuclear generators. In addition, system flexibility may change somewhat on a seasonal basis, as different generation mixes are made available.

Some insight into the overall flexibility of systems can be determined by examining real-time wholesale electricity prices in regions where such data is available. When the local wholesale price of electricity drops below the actual cost of generating electricity, it can be assumed that the utility is highly motivated to increase local demand and keep units operating either for local reliability, or to avoid units falling below minimum loading conditions. Historical wholesale price data is available in several parts of the United States, including PJM, New York, New England, and ERCOT. For example, data from the PJM system for 2003 indicates that the wholesale price of electricity fell to levels well below the cost of fuel on a number of occasions, with the price even going negative during several hours of the year (PJM 2005). These events occurred near the normal minimum load of roughly 36% of peak load for that year, but appear to happen at levels of demand as high as 40% of peak load. This would imply a flexibility factor of about 60–65% for the PJM system.

Even if all conventional electricity-generating plants can cycle to zero output (representing a system flexibility of 100%), at extremely high levels of PV penetration, some curtailment of PV output would still be required. For example, if the PV system shown in Fig. 4 was doubled in size (in an attempt to provide 20% of the system's energy from PV), the net load on Tuesday and Wednesday would be less than zero, clearly forcing curtailment of PV output. It is apparent that many combinations of system flexibility, PV system size, daily load, and PV generation will produce surplus PV generation.

There are a number of possible solutions to dealing with surplus PV output. One possibility is simply rejecting the excess PV generation—a strategy occasionally employed to deal with excess wind generation. The best example of this is perhaps the Danish power system, which currently has a large installed base of wind generation (Lund, 2005). Due to its reliance on combined heat and power electricity plants for district heating, the Danish system needs to keep many of its power plants running for heat. Large demand for heat sometimes occurs during cold, windy evenings, when electricity demand is low and wind generation is high. This combination sometimes results in an oversupply of wind, forcing curtailment of wind turbine generation. This scenario is somewhat analogous to our hypothetical scenario of large PV supply and low electric demand on a sunny day with moderate temperatures. Under these conditions, excess PV energy could be rejected by a utility operator by turning off some fraction of the installed PV capacity. This strategy would increase the average cost of PV-generated electricity.[3] It might, however, be an acceptable strategy if the level of surplus PV represents a relatively small fraction of total PV output, and PV output can be more fully utilized during other times. In this paper, we focus on understanding the implications of pursuing this type of strategy and provide a boundary analysis of the limitations of existing generators to accept the variation in PV generator output under high PV penetration scenarios. In a follow-up work, we examine strategies to overcome the limitations of existing utility system flexibility.

[3]The levelized cost of energy (LCOE) for a PV system is based to the levelized system costs divided by energy production. If the production decreases due to surplus output, the LCOE of the system will increase.

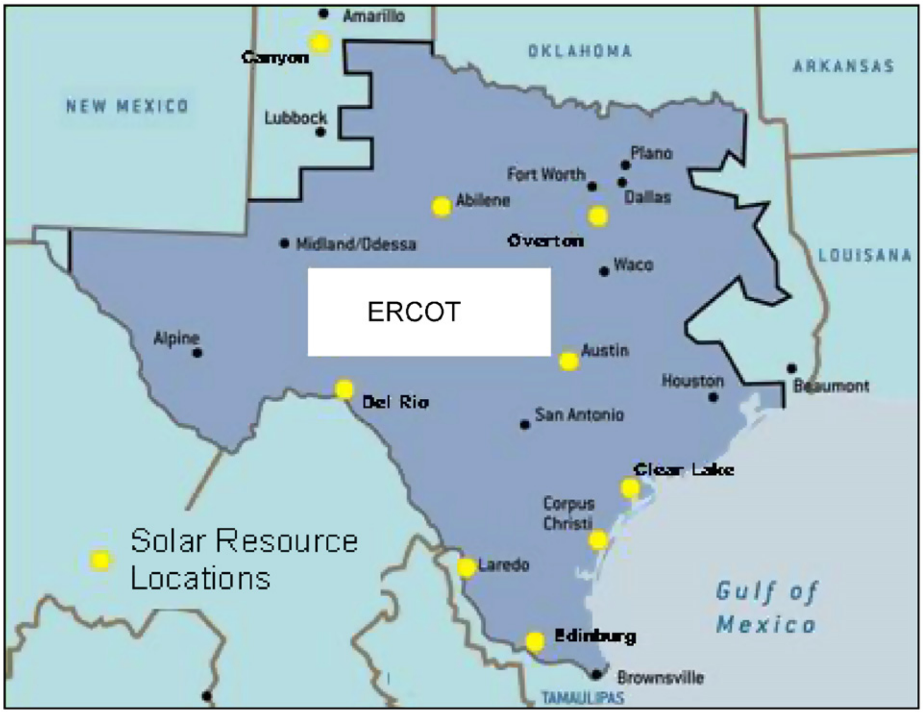

Fig. 5. Map of ERCOT territory and solar resource sites used in the analysis.

3. Analysis methods

The basic analysis used in this study involves a comparison of solar PV output with normal electricity demand on an hourly basis throughout an entire year. To analyze possible impacts of PV at high penetration, a PV load model (PVflex) was constructed to allow examination of possible impacts of large PV utilization. The model superimposes scalable PV output on load data at an hourly level. The model allows PV energy to be utilized or rejected, based on a system's flexibility. An accurate simulation requires a number of datasets and assumptions related to solar resource, system load, and utility system operation.

3.1. Solar generation

To provide a large fraction of a system's energy, PV systems would likely be spread over a large area to maximize regional benefits and provide a spatially diverse resource. To accurately match actual load conditions with actual solar resource data, a spatially diverse set of hourly solar resource data was obtained for Texas (Wilcox, 2005). Characteristics of an "ideal" dataset include a large number of sites with good spatial diversity with insolation recorded for each hour of the year. In addition, the dataset should be from a location and year where load data is available. We were able to obtain detailed hourly resource data from 2000 for the 9 Texas locations shown in Fig. 5. The data is average hourly global horizontal radiation taken at 1-h intervals. About 3% of the individual hourly site measurements were corrupted or missing. On these hours, we used data from the closest adjacent site, or the average of the two nearest sites. To provide more spatial diversity, especially considering limited coverage in eastern Texas, we included one site (Canyon) that is not actually in the ERCOT territory. This set of 8760 hourly solar insolation values was then used to simulate a large PV system distributed over the ERCOT territory.

At high PV penetration levels, it is assumed there will be a variety of PV orientations to accommodate different roof styles, building orientations, and utility-deployed solar-tracking arrays. In this study, we assume the following "mix" of array orientations: 15% flat, 10% south facing at 10° tilt, 15% south facing at latitude tilt, 10% southwest facing at 10° tilt, 10% southwest facing at latitude tilt, 20% single-axis tracking, 20% two-axis tracking. This mix of orientations is meant to capture the potential benefits of diversity. It is not designed to be the optimal mix and should be viewed as being illustrative rather than prescriptive.

The solar resource data was converted into AC solar PV output for each of the 63 location-orientation combinations (9 sites $\times$ 7 orientations) using HOMER (National Renewable Energy Laboratory, 2005).[4] For each site, the set of orientation-specific hourly PV outputs (i.e. from the seven different PV orientations) were combined into a site-specific composite output, based on the distribution of orientations described above. These composite outputs

[4]HOMER is a publicly available tool that contains an algorithm to convert global horizontal radiation measurements into PV electrical output using the HDKR model (Duffie and Beckman, 1991).

were then combined into a statewide composite PV output, assuming a uniform geographical distribution.

3.2. Load and utility system assumptions

The availability of solar resource data largely dictated our choice of the ERCOT system. However, the ERCOT system has several characteristics that make it a good system to simulate. ERCOT is a large system, serving about 20 million retail customers (85% of the state's load), with a peak demand in 2005 of about 60 GW, and a total annual demand in 2005 of 300 TWh (Saathoff et al., 2005).[5] In addition, the ERCOT system is electrically isolated from the rest of the United States, with a small import/export capacity of <1 GW. As a result, electricity generated in ERCOT must be used in ERCOT and vise versa.

In setting up our analysis, we made a number of assumptions about the utility system related to projected load growth, load profiles, transmission capacity, and transmission and distribution (T&D) losses. Below, we briefly discuss each of these assumptions.

Because this analysis focuses on the penetration of solar PV as a fraction of total energy, load growth on an energy basis will not impact our results, so it is not considered in this analysis. However, the shape of the daily and seasonal load profiles is critical for understanding how PV interacts with the system. While the load profile may change over decadal timescales due to changes in weather patterns, building technology, equipment, appliances, etc., these changes are hard to predict, so we assume the relationship between solar insolation and electric demand remains constant. The results of our follow-up analysis, however, do provide insight into the impacts of different-shaped load profiles on the usability of PV.

In our analysis, we assume that most of the PV generation is used at or close to the generation point, and do not consider possible transmission constraints. We do, however, include the possible impacts of T&D losses. Utility loads are measured at central locations so T&D losses then are considered part of the net load. A PV system generating at the load site would offset not only the actual load, but also the losses associated with delivering electricity to the load site.

Precisely quantifying the T&D loss offsets from PV would require a detailed load flow analysis to determine how much PV is being used at each load center during each hour of the year.[6] To capture some of the T&D loss reduction that would occur from the use of distributed PV, but without performing a detailed load flow and marginal loss analysis, the following simplifying assumptions were used:

(1) Fifty percent of all PV generation is assumed to be used on-site and does not incur T&D losses.
(2) ERCOT's average T&D loss rate in the year 2000 (6.5%) (EIA, 2000) is applied to this on-site generation, resulting in a generation offset of 1.07 kW for each kW of on-site PV generation.
(3) The remaining 50% of PV generation is assumed to be either "remote" utility PV generation or PV generation that must be transmitted in a traditional manner, incurring normal losses. This generation offsets traditional generation on a 1:1 basis.

These assumptions are generally conservative, especially considering that higher than average loss rates occur during high-demand peak PV output periods. At high penetration, it will be important to perform detailed load flow analysis, considering T&D constraints and the ability of T&D systems to handle the aggregated power flows from thousands of individual small generators.

3.3. Model methodology

The PVflex model is designed primarily to analyze the average and marginal effects of PV on an electricity generation system at high penetration levels. The model is based on an Excel spreadsheet that contains the 8760 hourly load profile and simulated composite PV output data for the analyzed region, (in this case, ERCOT in 2000). The load profile and PV output data are read into a series of Visual Basic for Applications (VBA) tools that scale the PV output data to different sizes, and analyze the resulting system impacts. First, the regional composite PV output for each hour is multiplied by a scaling factor to achieve a PV system of any desired size. To analyze the marginal effects at different levels of penetration, the model must first build enough PV to achieve an overall goal of meeting the desired fraction of system load. This is accomplished by iteratively increasing the PV scaling factor until the total *usable* annual PV production divided by the annual system energy demand equals the desired fraction of system load.

Once the desired PV system is "built," usable PV production is determined at each hour by comparing the PV system output to total system demand. If the PV output exceeds system demand during any hour, then the excess PV output during this hour is deemed "unusable." Excess PV is only the amount of PV generation that reduces the net load to below system minimum. The system minimum is an input to the model based on a fraction of system peak, representing the inherent limits of "must-run" generators.

Figs. 6 and 7 illustrate the basic process for determining the amount of surplus PV generation. Fig. 6 illustrates the normal load for 1 January, with a minimum generator loading of 30% of peak. In this example, enough solar PV

[5]For comparison, ERCOT's total electric demand in 2005 was between the demand of Spain (253 TWh) and the United Kingdom (372 TWh) (EIA, 2005c).

[6]Loss rates depend on the instantaneous loading of the system. In particular, resistive losses, which are a high percentage of total T&D losses, are proportional to the square of the load, and therefore vary from hour to hour.

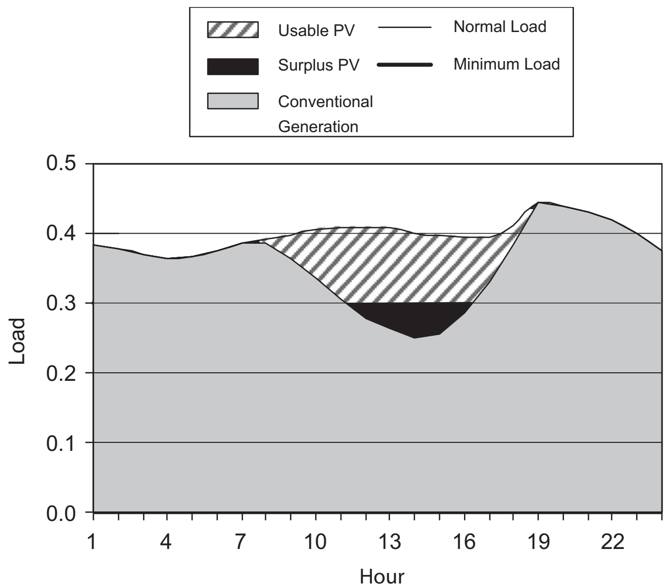

Fig. 6. Usable and surplus PV on 1 January, with PV meeting 9% of annual load and 70% system flexibility.

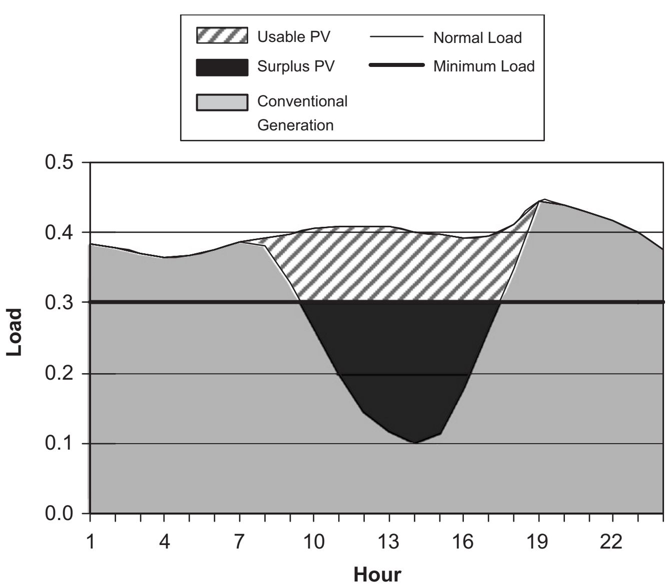

Fig. 7. Usable and surplus PV on 1 January doubling the PV capacity illustrated in Fig. 6.

has been built to provide approximately 9% of the system's load on an annual basis. The bulk of the day's demand (about 92%) is met with conventional generation. The majority of the day's PV production is usable by the system; however, about 16% of the day's PV generation exceeds what can be used by the system due to minimum loading constraints.

Fig. 7 illustrates the impact of doubling the installed PV capacity. Because PV output is highly concentrated in the middle of the day, the bulk of the additional PV energy on this day is surplus generation. As shown in the figure, additional usable solar generation occurs only during the "shoulder" periods, i.e. during the beginning and end of the day. The total amount of surplus solar on this day has increased from 16% to slightly more than 50%. However, the marginal surplus rate of this incremental amount of PV is much higher—about 86% of this additional solar generation is surplus generation on this day. As a result of this unusable generation, the increase in PV's contribution to the system is minimal—the daily fraction of energy met by PV on this day has increased from 8% to only 9%.

In carrying out the full analysis, PVflex repeats this calculation of average and marginal surplus solar rates for each hour of the year. It compares usable net load with solar to the usable load determined by the system flexibility factor.

4. Results: impacts of high PV penetration in conventional electric power systems

The general impacts of PV on net system loads can be observed by generating a revised load duration curve for increasing PV penetration. Fig. 8 illustrates the ERCOT 2000 LDC for systems where PV provides up to 22% of the system's energy. In this figure, the system flexibility factor was set to 65%, meaning that PV generation is useful only when the net load is greater than 35% of the annual peak load. At low penetration rates, a large fraction of PV output is coincident with high periods of demand. Thus, at low penetration rates, a significant fraction of PV generation offsets high fuel cost, low efficiency, and often high emissions peaking generation. As PV penetration increases, the amount of net load below system minimum increases, and falls below zero for many hours of the year. The "knee" of the curve in Fig. 8 becomes more prominent at increasing penetration, largely due to the fact that PV is strongly concentrated in a relatively small fraction of daytime hours, as illustrated in Figs. 6 and 7.

Fig. 8 indicates that to achieve very high penetration of PV generation on an energy basis, a significant amount of the electricity generated by PV will need to be either rejected or used in some other manner than meeting

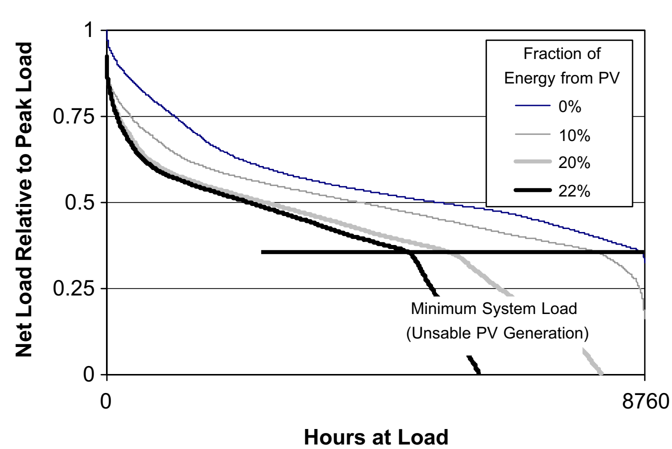

Fig. 8. Modified load duration curves for various levels of PV penetration.

traditional electricity loads. If PV-generated electricity is relatively inexpensive, it is possible that a desired penetration level of PV can be achieved simply by "turning off" PV generators to avoid electricity oversupply. The amount of surplus PV energy, however, is strongly dependent on overall electric system flexibility. If the system flexibility is high, more PV generation can be accepted as the net load drops closer to zero. For a utility system reliant on base load plants, whose output cannot be significantly reduced, a greater fraction of PV output will be unusable.

Fig. 9 illustrates how the fraction of surplus PV energy changes as a function of the share of energy provided by PV for three flexibility factors: 60%, 80%, and 100%. Both marginal and average surplus rates are shown, with the marginal surplus rate representing the unusable share of the incremental or next unit of PV installed at a particular point. The marginal surplus rate can reach 100% if all incremental PV energy is unusable. The average surplus rate represents the fraction of unusable PV for all units of PV installed up to a particular point. The average surplus rate will asymptotically approach 100% at high levels of PV penetration. The graph contains three sets of curves, representing different system flexibility factors. While a 100% flexibility factor curve is provided to illustrate the boundary condition, this is unrealistic. As discussed above, a flexibility factor closer to 60% is probably more realistic, considering limitations of existing power systems.

Fig. 9 illustrates that providing 50% of the systems energy from PV appears to be close to the technical limit (without storage, load shifting, etc.) even with a completely flexible power system. The marginal spill rate at this point is very close to 100%, meaning that any additional PV will provide very little usable energy into the system. This implies that roughly half of the electricity consumed in this region during this year (Texas in 2000) occurred when the sun was not shining.

If surplus PV energy goes unused, i.e. no alternative use for this surplus PV output can be found, then the effective PV capacity factor drops as PV system penetration increases. Fig. 10 illustrates how the average and marginal PV system capacity factor drops as the PV penetration level increases. The figure includes curves for the same system flexibility factors as shown in Fig. 9. In Fig. 10, both the relative and absolute system capacity factors are shown. The "absolute" system capacity factor is defined as the annual usable kWh produced per peak AC kW installed/8760. The "base" capacity factor (based on the system's AC rating) of the entire simulated PV system is 20.5%

As the PV system capacity factor drops, the resulting cost of PV-generated electricity increases, because the levelized cost of electricity from PV is proportional to 1/Capacity Factor. Fig. 11 illustrates how the marginal and average relative cost of electricity from PV changes as the level of PV penetration increases. The cost of energy in this figure is measured as relative to a "base" cost of 1, i.e. the cost of electricity from a PV system with fully utilized output. There is a considerable difference between average and marginal costs, particularly at high penetration levels. For example, to achieve a 30% penetration level of PV in an 80% flexible system, the average cost of PV would be 1.5 times the base cost. In other words, if the "base" cost of

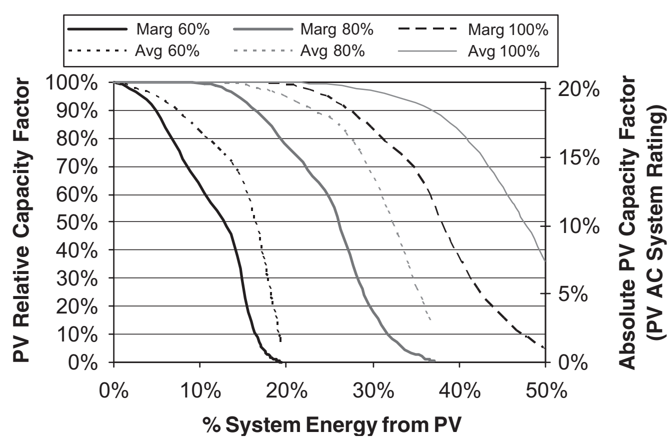

Fig. 10. PV capacity factors as a function of PV penetration at three system flexibilities.

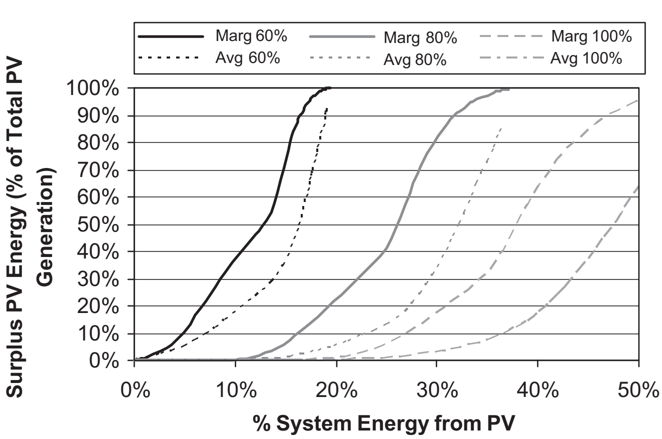

Fig. 9. Surplus PV energy as a function of PV penetration at three system flexibilities.

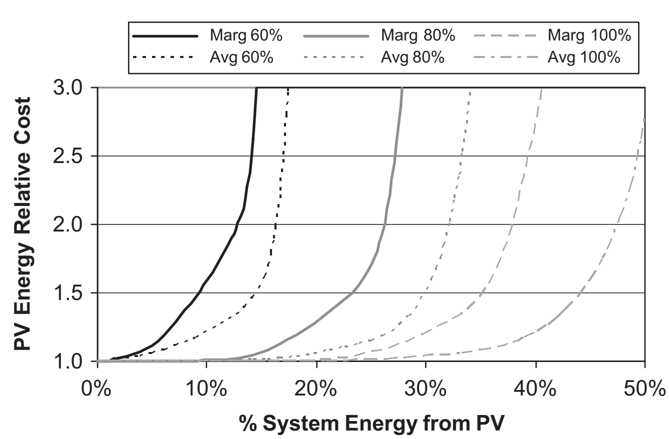

Fig. 11. Relative cost of PV electricity as a function of PV penetration at three system flexibilities.

PV-generated electricity were 10 cents/kWh, the average cost of *every* kWh of PV used in this system would be 15 cents/kWh in the 30% penetration/80% flexibility case. However, at the margin, the "last" unit of PV installed to meet the 30% penetration level would cost around four times the base cost, or 40 cents/kWh. It is unclear whether the average or marginal costs will be the limiting factor, but this issue may be of some importance when evaluating the likelihood of high PV penetration—especially considering that, at high penetration levels, PV likely will be installed by a mix of utilities and individuals.

It is important to note that considerable PV capacity is needed before minimum loading conditions occur, even on a relatively inflexible system. Fig. 12 illustrates the capacity required to achieve high levels of PV penetration on an energy basis. In an ideal case, where no energy is spilled, both usable PV energy and the percent of system energy from PV would vary linearly with PV capacity. In other words, doubling the size of the installed PV capacity would double its contribution to the grid. The relationship between PV capacity and fractional PV system energy is determined by the PV capacity factor and system load factor expressed as

$$\begin{aligned}\%\ \text{system energy from PV}\textit{Break} &= \text{PV capacity} \\ &\quad \times \text{PV capacity factor}/\text{system load factor},\end{aligned}$$

where PV capacity is measured as a fraction of peak load, and the load factor is the average system load expressed as a fraction of peak load. It should be noted that because the PV capacity is measured relative to load, and therefore its peak AC output, the actual installed total DC PV capacity would be higher, reflecting inverter inefficiencies, etc.

Fig. 12 demonstrates that the departure from the linear relationship occurs only after a sizable amount of PV has been installed. Even at a 60% flexibility factor, increased PV costs (due to minimum loading constraints) occur after an installation of PV capacity that is equal to about 20% peak load. For comparative purposes, the peak load in the ERCOT system was about 60 GW in 2005, meaning that this system could incorporate about 12 GW of PV before issues of minimum loading would occur at a 60% flexibility factor. This amount of PV is equal to about 120 times the amount of PV installed in the entire United States in 2005 (PV News 2006b). If we assume the same general relationship in the entire United States, with a 700 GW peak load in 2004 (EIA, 2005d), then this intermittency impact would occur only after the installation of about 140 GW of PV. This value is about 1400 times the United States and 80 times the global annual PV installations in 2005 (PV News 2006a). Clearly there is a lot of room for the PV industry to grow in the United States and worldwide before these sorts of intermittency impacts become critical. As the industry matures, however, it does make sense to begin thinking about ways to overcome system-level limitations for very high PV penetration levels.

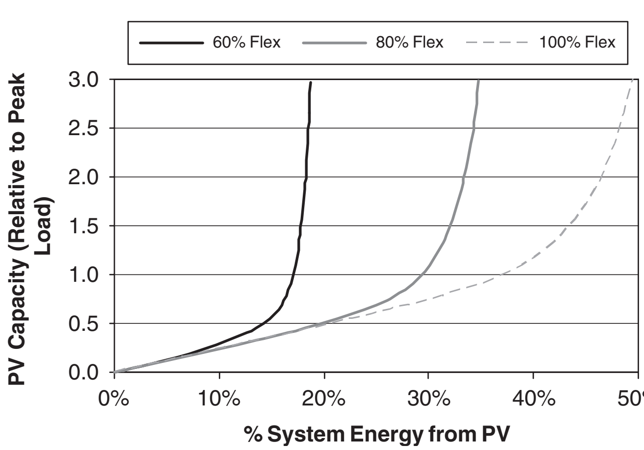

Fig. 12. PV size as a function of energy penetration at three system flexibilities.

5. Conclusions

Unlike conventional generators, intermittent sources of electricity cannot respond to the variation in normal consumer demand patterns. Rapid fluctuations in output can impose burdens on generators and limit their use. The ability to integrate fluctuating sources is improving, and it is unclear to what extent these short-term fluctuations limit the fraction of a system's energy that can be provided by intermittent renewables. There is, however, a somewhat absolute limit to the economic integration of renewable energy sources such as solar PV, based on the fundamental mismatch of supply and demand. Only so much solar PV can be integrated into an electric power system before the supply of energy exceeds the demand. This problem is exacerbated by conventional power systems, which have limited ability to reduce output of "must-run" base load generators.

This fundamental imbalance of supply and demand likely represents the ultimate limit on system penetration of intermittent renewables in conventional electric power systems. The concentration of solar PV output in a relatively narrow daily window produces unusable energy, and hence unusable PV capacity, which will increase costs beyond a point that is determined by a system's flexibility. This increase in cost will inhibit the ability to achieve very high PV penetration under a "spilled energy" scenario.

Given the long lifetimes of many electricity generation technologies, it may be useful to think creatively about ways to begin moving toward a more flexible and PV-friendly electric power system. To move beyond the limits of PV in traditional electric power systems, limited by the flexibility of thermal steam generators, we evaluate alternatives that might increase economic penetration of intermittent solar generation in follow-up work. The PV "enabling" technologies evaluated include increased system flexibility, dispatchable load, and energy storage. We examine the amount of enabling technologies needed to allow increased use of solar PV, to the point where this technology may provide 50% or more of a system's total generation requirement.

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