Chapter 8 – Integration of Solar Generation in Wholesale Electricity Markets

This chapter explores the economic impact of large amounts of solar generation competing in free wholesale electricity markets with conventional thermal technologies. We do not seek to prescribe suitable regulatory and policy responses to the scenarios considered in this chapter, nor do we attempt to predict future prices and generation mixes. Furthermore, many detailed technical considerations — such as impacts on voltage stability, reserve capacity requirements, and the value of precise forecasting — are not included in this analysis.[1,2,3] Rather, the chapter aims to develop general insights concerning the primary effects of large-scale solar production on different generation mixes in the wholesale electricity market over a medium-to-long-term time frame.

Our discussion of market integration issues is divided into seven sections. Section 8.1 introduces the main questions considered in this chapter and the general approach followed. Section 8.2 summarizes the general characteristics of solar photovoltaic (PV) generation and its interaction with electricity demand. Though the focus is on PV generation, the conclusions reached in this section also generally hold for concentrated solar power (CSP) without storage. In Section 8.3, we analyze the major short-to-medium-term impacts of increased PV production, focusing on a time scale that is sufficiently short that the high rate of solar PV deployment does not allow the generation technology mix to adapt. In Section 8.4, we consider a longer time scale, allowing changes in the generation mix (i.e., new investments better adapted to a market with high levels of solar penetration). Additionally, we consider the impact of two key factors: (1) per-kilowatt-hour (kWh) support mechanisms for solar technologies and (2) the original composition of the technology mix (e.g., amount of hydropower generation). In Sections 8.5 and 8.6, we briefly analyze the potential role of energy storage, including both energy storage that is external to PV facilities and energy storage incorporated in CSP power plants. Section 8.7 highlights major conclusions. Throughout this chapter we take final demand as given to highlight the wholesale-level challenges posed by substantial PV generation. Thus we do not model the use of dynamic pricing or other demand response techniques to reduce those challenges, even though demand response techniques have considerable potential to aid the penetration of solar generation.

8.1 INTRODUCTION

This chapter attempts to shed light on a question of increasing concern to stakeholders and policymakers: what will electric power generation systems — and, more specifically, wholesale electricity markets — look like if solar generation eventually becomes a significant or even dominant player? In broad terms, we examine how a significant penetration of solar generation could affect operations, planning, and market prices in electric power systems at the wholesale market level.

A major concern is the impact of solar PV on wholesale electricity prices. For instance, it is often said that a marginal-cost-based market mechanism will not make sense in the context of very high solar penetration, since prices will frequently be zero (or even negative if solar output is subsidized on a per-kWh basis) and new investments in necessary conventional generation will not be financially viable.

A major concern is the impact of solar PV on wholesale electricity prices.

We approach this subject in four steps:

1. We begin by reviewing the main characteristics of typical solar PV production profiles over time and explore their interactions with different electricity demand profiles.

2. Next, we investigate how solar generation can affect the market when PV systems deploy so rapidly that the rest of the technology mix does not have time to adapt. Specifically, we examine potential changes in the daily dispatch of various existing conventional power plants and the implications of these changes for the determination of market prices. To analyze these impacts, we simulate different levels of solar PV penetration in a power system with an already installed generation mix (see Appendix F for details).

3. We then examine how a massive penetration of solar generation could come to condition the future configuration of the generation technology mix, and what could be expected — in terms of impact on wholesale prices — from this new, adapted mix. Again, we simulate different levels of PV penetration over the same system, but we also allow the mix to optimally re-adapt to the new conditions imposed by the amount of solar PV that is present in each case.

4. Finally, we provide some insights into the key role that energy storage could play in facilitating the penetration of solar PV and other intermittent generation technologies.

To estimate how the system operation and generation mix might evolve with greater PV penetration, we analyzed a range of scenarios using the Low Emissions Electricity Market Analysis (LEEMA) model.[i] All simulations use 2030 as the reference year.

8.2 INTERACTIONS BETWEEN ELECTRICITY DEMAND AND SOLAR PHOTOVOLTAIC PRODUCTION

Since solar is a zero-variable-cost energy source,[ii] solar plants that lack energy storage capability will most likely be dispatched whenever they are available. This is also true for wind or run-of-river hydro and, in practice, it is also the case for some existing nuclear power

[i] LEEMA is an optimization tool that solves for capacity expansion requirements and short-term operational needs in a fully integrated manner. The model was developed by researchers at Comillas University as part of the MITEI-Comillas collaboration (COMITES program) on the future of the electricity and gas sectors. A description of the basic structure of the model can be found in Batlle and Rodilla.[4]

[ii] Because the fuel to operate solar plants — i.e., sunlight — is free, the marginal cost of producing an additional kWh of electricity at an existing solar facility is zero. This is not generally true for conventional fossil fuel power plants.

plants, given their low variable cost and minimal operational flexibility. For low to medium penetrations of solar PV, the profile of the load that is left to be supplied by other technologies will be the direct result of subtracting solar production from total load (what is usually known as *net load*).[iii] The ability of solar generators to reduce system operating costs and capacity requirements depends on the correlation between solar electricity production and electricity consumption.

Peak Load Reduction

Figure 8.1 shows an example of net electricity demand, in gigawatts (GW), on a typical summer day in 2030 at different (and increasing) penetration levels of solar PV within the Electric Reliability Council of Texas (ERCOT)[iv] control area.

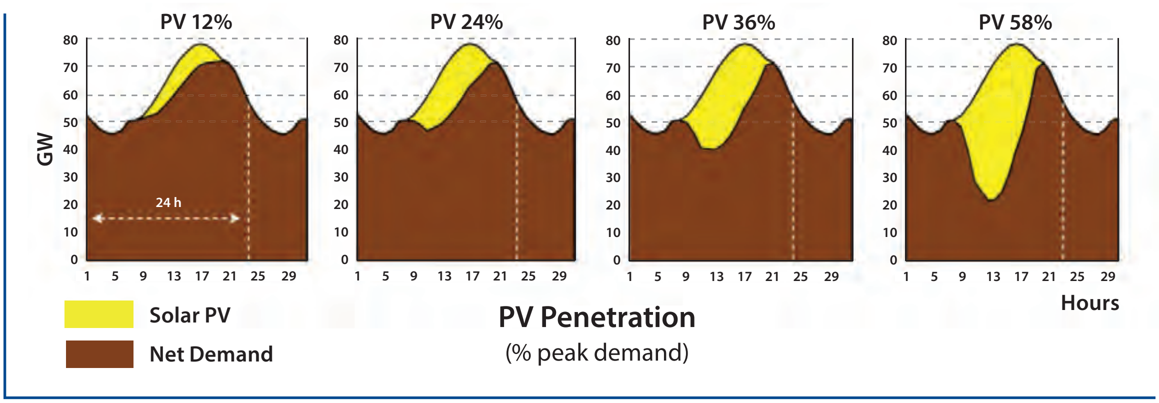
When annual peak loads are driven by summer daytime cooling demand (as is the case for ERCOT), higher levels of solar PV penetration reduce the annual net peak load. Specifically, Figure 8.1 shows that, as solar penetration grows, the net peak load progressively decreases, narrows, and shifts in time (toward a few hours after sunset). At a certain point in the evening, net load stabilizes and is unaffected by any further increase in solar penetration until the next day.

As solar penetration grows, the net load peak progressively decreases, narrows, and shifts in time.

The situation is different when peak demand is dominated by winter loads (primarily for heating). This effect is predominant in the European case, but is not so relevant in the United States. All North American Electric Reliability Corporation (NERC) regions in the contiguous United States peak during the heavy air-conditioning summer months, except for the winter-peaking Northwest NERC region.[5]

Figure 8.2 shows loads for one typical winter day and one typical summer day in the United Kingdom in 2012 at several levels of solar PV penetration. In this case, annual net peak load is not reduced by solar PV generation because the net peak occurs after sunset.

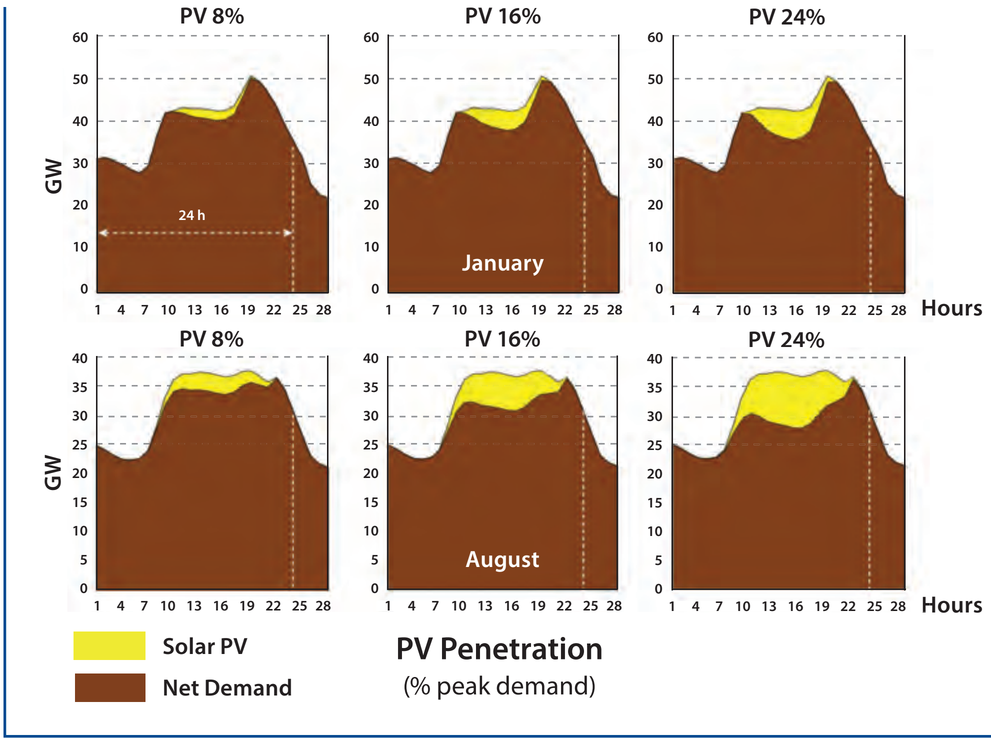
Figure 8.1 ERCOT Net Load for a Typical Summer Day at Different Levels of Solar PV Penetration



[iii] This simple subtraction is not strictly the case for large penetrations of solar PV, which frequently require the curtailment of solar production for reasons that are discussed in a later section.

[iv] ERCOT is one of several regional entities that are responsible for ensuring the reliability of the bulk power system across the United States; its control area covers most of the state of Texas.

Figure 8.2 Net Load for Different Penetration Levels of Solar PV in Winter and Summer in the United Kingdom



In sum, our analysis — described in more detail below — finds that solar generating facilities without energy storage reduce the power system's overall capacity requirements only for moderate levels of solar penetration and for systems with summer annual peak loads.

FINDING

With a large penetration of solar PV, incremental PV does not significantly reduce the annual net peak load of the power system. Indeed, in regions where electricity demand peaks after sunset, adding PV generation without storage does not reduce annual peak load at all.

Valley Load Reduction

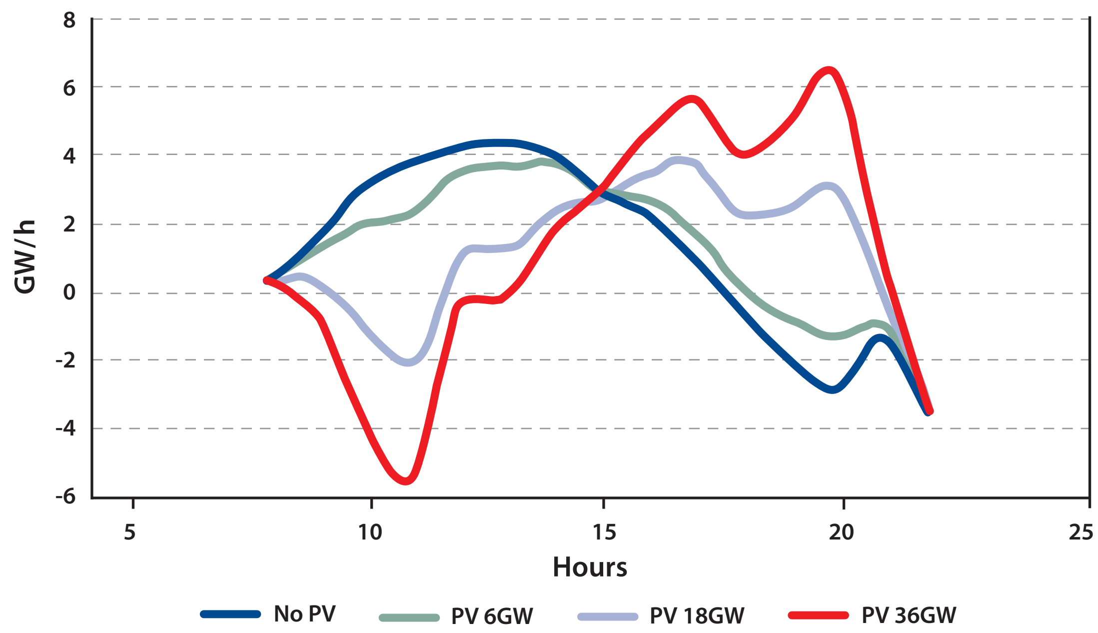
Figure 8.1 also shows that high levels of solar PV penetration can substantially reduce minimum daily net load. This minimum value, which appears as a load "valley" in the graph of net load, is relevant because it may limit the system operator's ability to keep thermal plants operating. As is well known, keeping a number of units operating is not only economical, but is also essential to ensure that the system has enough spare capacity to respond in real time to deviations from expected levels of generation and demand.

Impact on Ramping Requirements

Different levels of solar PV penetration also affect the incremental change in net load variation between two consecutive hours (known as the hourly ramping value). Figure 8.3 shows how these hourly incremental changes would evolve in ERCOT's net hourly load for different increments of solar PV generating capacity. At low solar penetration levels, net load ramps are reduced. However, at higher penetration levels, the ramps become steeper and the daily pattern of ramps changes significantly. It is also worth noting that in some hourly periods, solar generation reverses the direction of the required ramp. Where an upward ramp was required, now a downward ramp is needed, and vice versa.[v]

In purely thermal systems, increased ramping may increase operation costs for some generating units (e.g., non-flexible coal plants). At very high levels of solar PV penetration, the largest ramping needs usually occur just after net load falls to a minimum. The problem is that when net load is low (as a result of high solar PV production) many thermal units may be forced to shut down. Those units may not be available to immediately ramp up again. These two effects call for thermal flexibility: in other words, thermal generators must be able to start and stop frequently, to withstand large and rapid load variations from nominal value to minimum operating load (and vice versa), and to operate at lower minimum loads.

Figure 8.3 Hourly Net Load Ramps for Different Levels of Solar PV Penetration



[v]Similar observations about ramping requirements apply regardless of the season of the year. The consequences of short-term variability and the uncertainty of PV production are discussed in Mills et al.[6]

A large and rapid increase in solar PV capacity will initially affect just the operation and profitability of existing thermal generating facilities.

8.3 SHORT-TO-MEDIUM-TERM IMPACTS OF SOLAR PV ON SYSTEM OPERATION, COSTS AND PRICES

Electricity output from plants that utilize variable energy resources (VERs) like wind and solar is more variable, less dispatchable, and less predictable than the output from conventional fossil- and nuclear-powered generation plants. Typically, VER capacity (particularly solar PV) can be deployed much faster than thermal technologies. Therefore, when considering only relatively short timescales, a large and rapid increase in solar PV capacity will initially affect just the operation and profitability of existing thermal generating facilities.[7,8,9] Operational limits and the costs of cycling these facilities on and off are particularly relevant considerations in a near-term time frame, since some currently installed conventional thermal technologies (mainly coal plants but also some combined cycle gas turbine (CCGT) plants) were not expected to operate at the cycling regimes that are required by a strong presence of VERs in the resource mix generally, and a large PV presence in particular.

Two major short-to-medium-term effects on generation operation can be expected as a consequence of increasing VER penetration (ignoring the impact of potential transmission network constraints):

1. VERs, which have zero variable cost, tend to displace the most expensive variable cost units in the short term (such as fossil-fuel electricity generators).
2. At significant penetration, PV increases the cycling requirements imposed on conventional thermal plants. These plants are forced to change their output more frequently to meet load ramps associated with large changes in net demand. They have to decrease production to the minimum stable load for a higher number of hours, and they also have to start up and shut down more frequently.[10,11]

FINDING

A large penetration of solar PV displaces the plants with the most expensive variable costs and increases thermal plants' cycling requirements.

Note that the cost impacts of these two operational changes act in opposite directions. While the displacement of high-variable-cost units tends to reduce costs (particularly fuel-related costs), the greater cycling demands on conventional thermal plants generally augments fixed operation costs (particularly costs related to starts, operations, and maintenance).

In a market context, these two operational changes also affect short-term price dynamics:

- Replacing fossil-fuel plants with VER plants at zero variable cost can change the marginal technology and thereby modify marginal prices. This is the so-called *merit order effect*, which tends to reduce wholesale electricity prices.[vi]

[vi] The "merit order effect" on prices has been qualitatively and quantitatively analyzed. See for example Sensfuß et al.[12] or Morthorst and Awerbuch.[13]

- On the other hand, as cycling intensifies, the operation of the system becomes more expensive. For example, the individual cost involved with each additional plant start-up usually rises as the total number of starts grows (due to wear and tear on plant equipment). The need to recover these increased costs will tend to result in higher prices.

The importance of these effects depends heavily on the generation mix. For example, if a particular technology dominates the generation mix, merit order effects can be less significant. This is the case for some European and U.S. systems (for example, in Spain and California), where CCGT technology accounts for a very large share of the generation mix.

FINDING

The impact of increased solar PV penetration on market prices and plant revenues depends on the pre-existing generation mix.

Changes in the Operating Regime

This section begins by examining the impact of different levels of solar PV penetration on the operating regime of conventional thermal plants. Specifically, our analysis considers two representative power systems, which are based on the actual systems in place in Texas and California.

This discussion focuses on results obtained by simulating the Texas ERCOT system; we present results from simulations of the California system only insofar as they provide additional insights. It is worth noting that our selection of these two cases is not meant to predict the future behavior of these specific systems, but rather to provide a realistic basis for analyzing two different generation mixes.[vii] (The detailed data used in the simulations can be found in Appendix F).

In Texas, as in many other U.S. systems,[viii] electricity demand exhibits a strong seasonal pattern, with far higher peak loads in summer than in winter. Using the forecast demand profile for 2030, Figure 8.4 shows the optimal (lowest cost) generation schedule for different levels of solar PV penetration in two representative summer and winter weeks. Here, solar penetration is measured as the ratio of installed PV capacity to system peak demand.[ix] Although the figures show the operational implications of solar penetration levels from zero to, typically, around 40%, we do not mean to suggest that the highest levels of PV penetration shown represent an upper limit in any technical sense, particularly in a scenario where the generation mix has time to adapt.

Nuclear plants have the lowest variable cost of all thermal generation technologies and are often assumed to be totally inflexible from an operational standpoint.[x] Therefore, they are run as purely base-load plants. In the baseline scenario (i.e., no solar PV), coal plants run at

[vii] The modeling representation leaves aside many relevant details characterizing these systems (e.g., network, imports/exports, actual definition of ancillary services, etc.).

[viii] See, for example, Corcoran et al.[5]

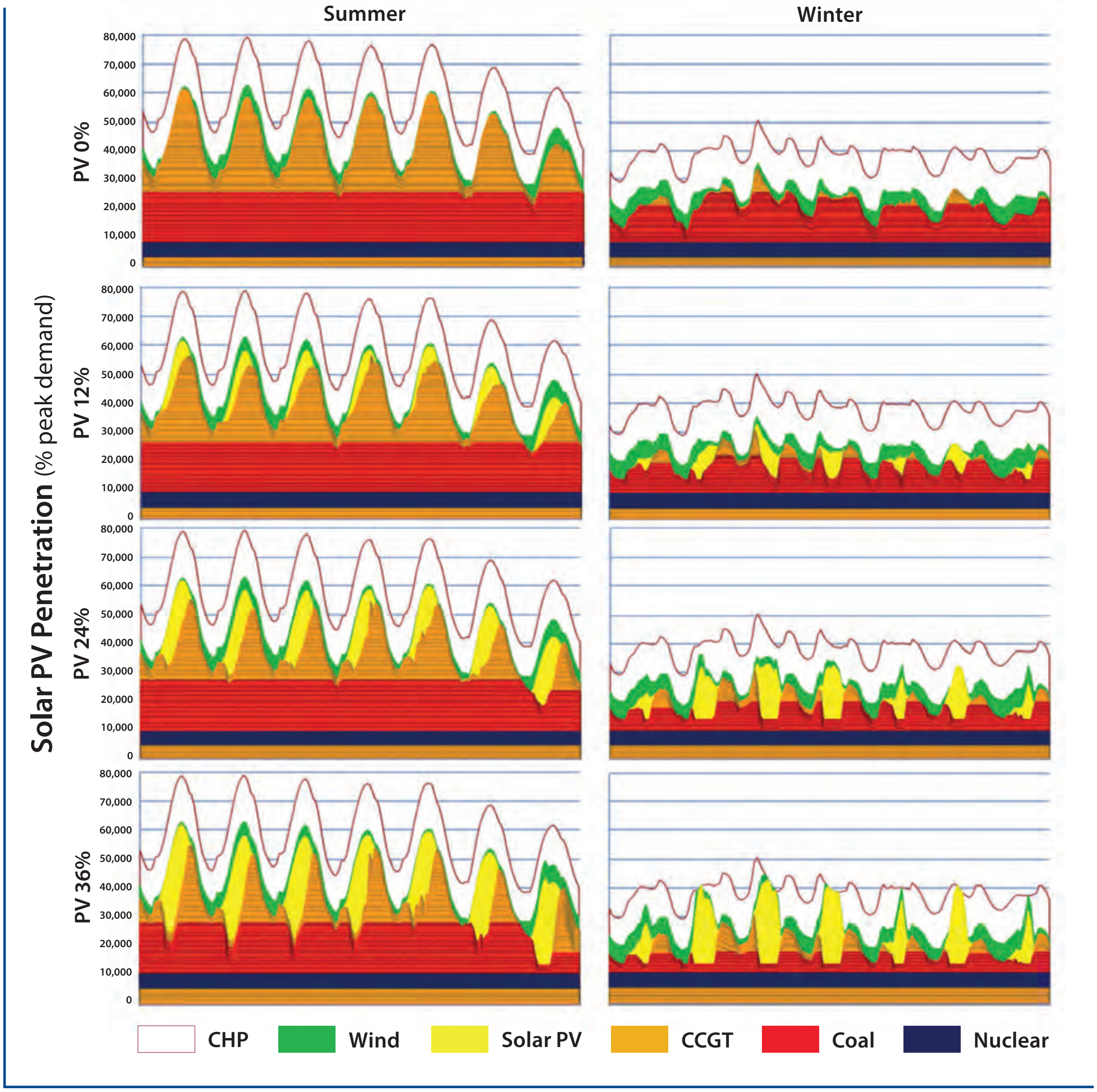
[ix] The penetration level can also be measured as the ratio of solar production to total energy demand. To convert the capacity-based value used in the figures and tables to an energy-based value, a factor of 0.42 (ERCOT) or 0.40 (California) has to be applied. For instance, in ERCOT a penetration of 36% in capacity corresponds to 15% penetration in energy.

[x] Properly designed or refurbished nuclear plants can be operated as flexible generators. However, with a few exceptions (e.g., in France and Germany), nuclear plants are usually operated in a pure base-load mode.

full capacity in both summer and winter during peak-load hours, but they follow different production regimes in summer and winter. While coal plants run at full capacity during most summer hours, they have to operate in a moderate load-following mode in winter. On the other hand, most CCGT production occurs in the summer. All CCGT plants operate at full capacity only during the summer peak-load hours. In winter, when electricity demand is lower, only a small fraction of installed CCGT capacity is producing at peak hours.

In Figure 8.4, production from generators that provide operating reserves (CCGTs in this case) is shown below nuclear production. This reflects the fact that a certain amount of capacity always needs to be operating at partial

Figure 8.4 Impact on System Operation Regimes as Solar PV Penetration Increases (Summer and Winter)



load so as to be able to provide upward and downward capacity reserves as needed to keep supply and demand on the system continuously balanced in real time. The contribution from combined heat and power (CHP) units in Figure 8.4 corresponds to actual CHP production profiles in ERCOT in 2012.

Several significant changes can be observed in Figure 8.4 as solar PV penetration increases:

- Solar PV production affects the already installed thermal generation mix to a different extent in summer and winter. In summer, solar production progressively reduces CCGT production, while in winter it affects coal production more significantly. As a result, coal units have to follow a much more seasonal operating regime, with some units not being dispatched at all during the winter.

- In a purely thermal system (as regards conventional generation), such as the one being analyzed here, the narrowing of demand peaks implies that an increasing number of units will need to produce during a small and decreasing number of hours. This could mean starting up a peak unit to produce for less than one hour. The costs of operating some units in this manner could be very high, resulting in electricity prices that are correspondingly high — e.g., above \$300 per megawatt-hour (MWh), as shown later in this discussion.

FINDING

In general, the higher the penetration of solar, the less production there will be from less flexible generation technologies. This effect is more acute in the season with the lowest levels of net demand.

Solar PV production affects the already installed thermal generation mix to a different extent in summer and winter.

- In general, coal production is more seriously affected than CCGT production at very high solar penetration levels. This is due to the lower cycling capability of coal plants, which generally are not designed to start up once a day. For systems with a large coal contribution (e.g., ERCOT), this effect can be relevant. On the other hand, it would be less of an issue in California or New England, just to mention two systems with only a small amount of coal production. Furthermore, when demand follows a strong seasonal pattern, as in the case of ERCOT, increasing solar penetration leads to a much more active cycling regime for thermal power plants in the low demand season (winter in this case), thus leaving less room for coal production in that part of the year.

In general, coal production is more seriously affected than CCGT production at very high solar penetration levels.

- The larger the solar PV presence, the larger the system's operating reserve requirements, leaving less flexible plants to meet system demand.[xi] This reduces overall system flexibility.[9]

- At high levels of solar penetration, the system must accommodate a large supply of non-dispatchable, zero-variable-cost production during several hours (with solar production adding to wind and CHP production in the simulation). This can significantly increase cycling needs and costs, thus making it economically efficient to "spill" some portion

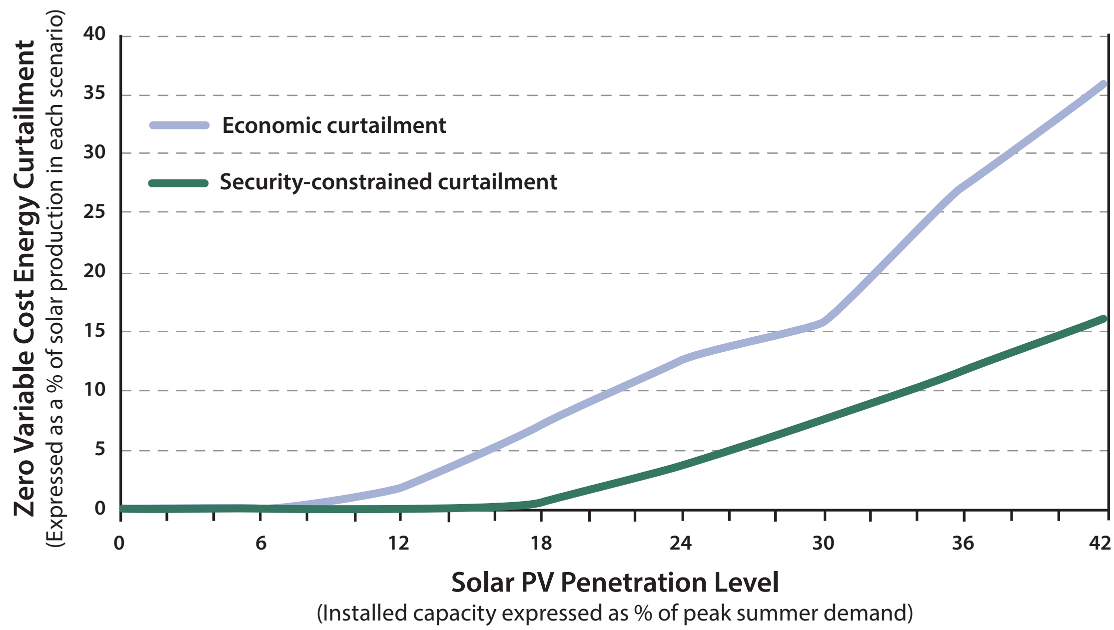
[xi] Operating reserves are calculated as the sum of the capacity of the largest thermal plant in the system, 0.5% of peak load and 0.2% of the installed capacity of intermittent generation. For the sake of simplicity, we assume that a constant amount of upward and downward reserves is required in all hours.

of the zero-variable-cost resource (in the simulation, this situation occurs mainly in winter, though it also occurs, to a lesser extent, in the summer). Roughly speaking, it is more cost efficient to not use all available zero-variable-cost production rather than force a coal plant to stop operating, only to start the coal plant up again a couple of hours later. Figure 8.5 shows the optimal level of curtailment as solar penetration increases for two scenarios: in one scenario VER generators do not receive any per-kWh incentive (so curtailment is exclusively driven by economic considerations);[xii] in the other scenario, the per-kWh incentive is so high that all VER production is used as long as doing so does not threaten the overall security of supply (threats to supply security could come from low operating reserve margins, for instance, or from the need to shut down a nuclear power plant). The figure shows the total amount of zero-variable-cost energy to be spilled, without entering into any discussion of the preferred merit order for curtailment (i.e., which types of generators — CHP, wind, or solar — should be curtailed first).

FINDING

At high levels of solar PV penetration, it will be increasingly necessary to curtail production from solar facilities (and/or from other zero-variable-cost generators) to avoid costly cycling of thermal power plants.

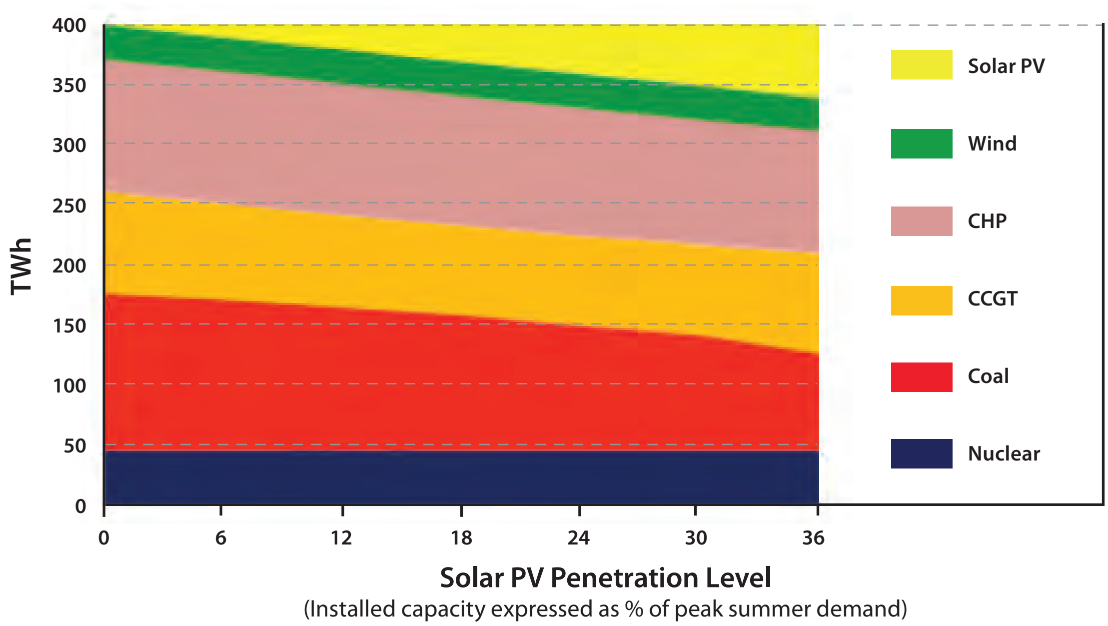
Figure 8.5 Economic Curtailment of Zero-Variable-Cost Energy



[xii] In a market context, this sort of curtailment entails prices that are zero or, in the extreme, negative, which would involve spilling all zero-variable-cost energy.

- Figure 8.6 shows total annual electricity production by technology as installed solar PV capacity increases. At low penetration levels, solar production affects both CCGT and coal production. At higher penetration levels, solar affects coal more seriously. Indeed, for very high penetration levels, we can observe a substitution effect between CCGT and coal.

Figure 8.6 Annual Electricity Production as a Function of Installed Solar PV Capacity



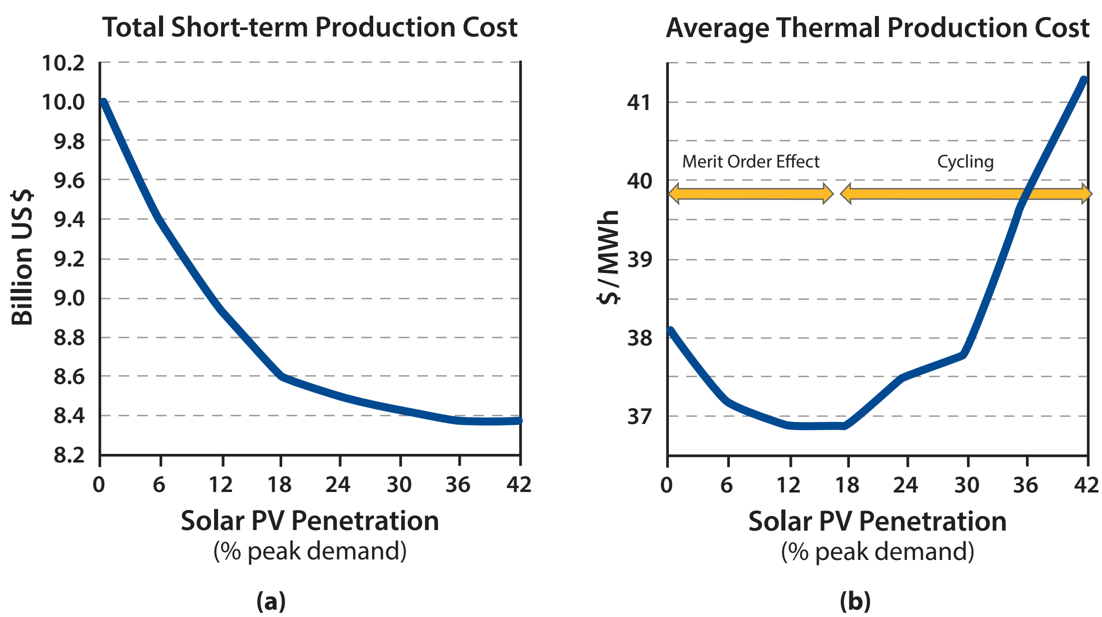
Changes in Production Costs

Absent energy storage capability, high levels of solar penetration result in the curtailment of a growing fraction of zero-variable-cost energy and a significant increase in the average operating costs of the conventional thermal plants that are subject to frequent cycling.[xiii] The evolution of total short-term thermal production costs (i.e., not including investment costs) as solar PV penetration increases is shown in Figure 8.7a. Notably, the rate of reduction of production costs with solar PV penetration diminishes smoothly.

After solar reaches a certain penetration level, the average cost of each MWh produced with conventional technologies increases because of higher cycling costs.

Figure 8.7b shows average short-term production costs for thermal generators only (in $/MWh) as solar penetration increases. At low levels of solar penetration this average cost decreases, as output from solar generators replaces output from the thermal plants with the highest variable costs via the merit order effect. After solar reaches a certain penetration level, however, this trend reverts and the average cost of each MWh produced with conventional technologies increases because of higher cycling costs.

Figure 8.7 Changes in Total Short-Term Thermal Costs as a Consequence of Solar PV Penetration



xiii Sections 8.5 and 8.6 show how the addition of energy storage could modify this picture.

Changes in Market Prices

Figure 8.8 shows the evolution of average market prices with increased PV penetration when no new generation capacity is installed. The graph shows a generally declining trend, indicating that the merit order effect prevails. However, this trend starts to revert slightly at very high levels of solar penetration, when there is an increase in the number of hours during which CCGT plants set the market price — to the detriment of coal generators, which start to disappear entirely because of their limited operational flexibility. A secondary effect that pushes prices up at high levels of solar PV penetration is the effect of cycling on production costs (particularly as a result of high costs related to unit start-up).

Note that these changes in market prices will generally affect the profitability of existing generators. This is particularly the case when capacity investments were made based on price expectations that assumed a low or non-existent solar contribution.

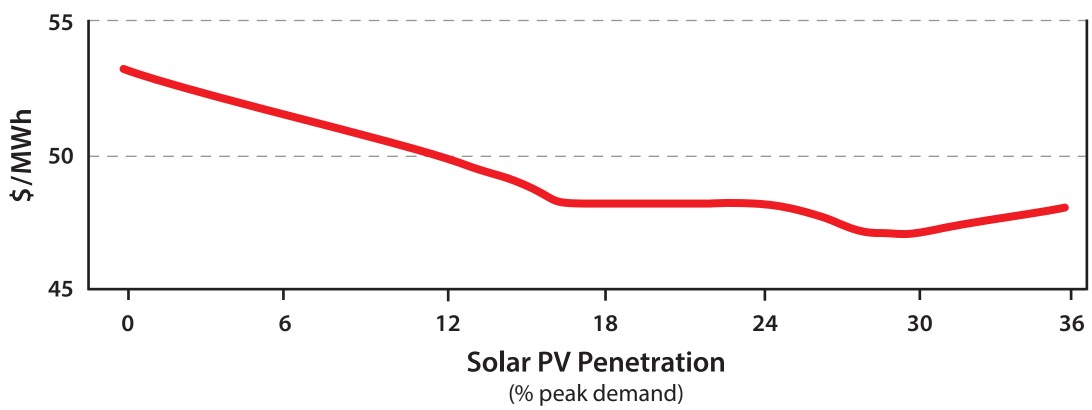
Figure 8.9 shows how a strong solar presence in the overall generation mix significantly changes the location and magnitude of peak prices for a particular day (corresponding to a Friday in summer, as demarcated by the dotted-line rectangular shape in the figure). In particular, high prices would be expected to coincide with

Peak price increases with higher levels of solar PV penetration.

net peak demand hours. Since solar shifts the time of net peak demand, it also shifts the timing of peak prices. The figure further shows that peak price increases with higher levels of solar PV penetration. This is because of higher costs for the operation of thermal generating units and narrower peak periods. On the other hand, prices fall in the two hours when the marginal technology changes from CCGT to coal.

Figure 8.10 portrays the annual price-duration curve.[xiv] While prices tend to decrease with higher levels of solar PV penetration during valley and shoulder demand hours, this is not the case during peak hours when a strong solar presence slightly raises prices. No price limits

Figure 8.8 Evolution of Average Market Prices



[xiv] In the price-duration curve, annual hourly prices are sorted in descending order, so that the curve starts from higher values and is monotonically decreasing. The price-duration curve is useful for finding the number of hours that a certain price was exceeded in the simulation.

Figure 8.9 Evolution of Peak Prices Due to Increasing Solar Penetration

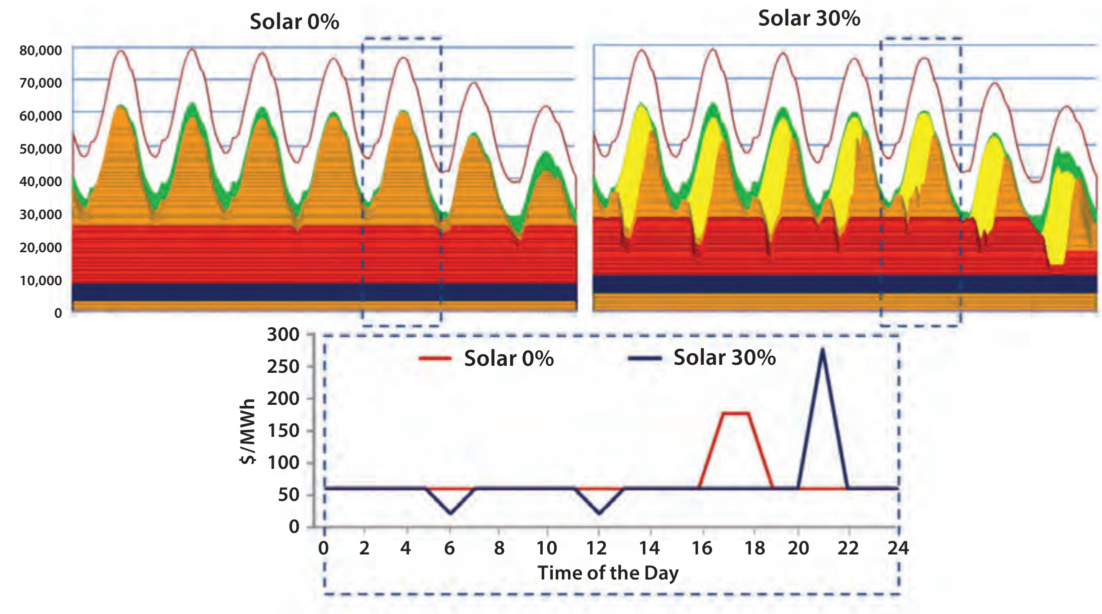
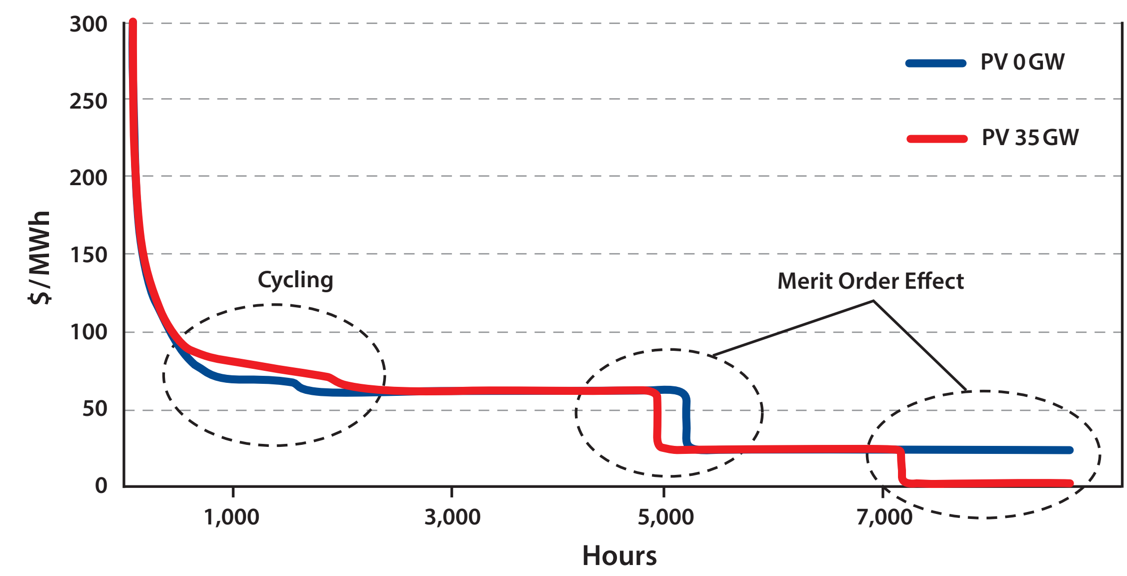


Figure 8.10 Price-Duration Curves for Two Scenarios of Solar Penetration



were imposed in these simulations, but it is worth noting that most actual electricity markets have price caps. In the particular case of ERCOT, the price cap can barely be considered a limit since it was set at $7,000 per MWh at the time of this writing (the ERCOT price cap is expected to increase to $9,000/MWh in 2015). In the European electricity market, there are plans to implement a homogenous EU-wide €3,000/MWh price cap.

Revenues of Solar PV Generators under Competitive Market Conditions

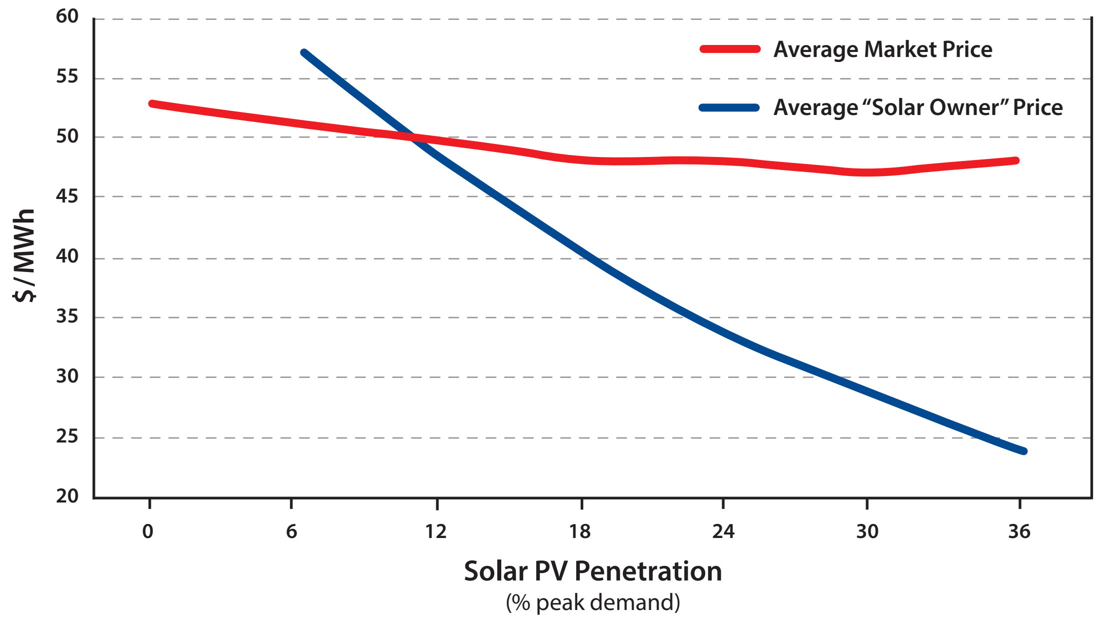
One of the major concerns presently being expressed by stakeholders is whether, in a system with a competitive wholesale electricity market, a cost-competitive solar PV technology would, by itself, either stop further capacity investments at a certain penetration level, or end up completely flooding the electric power system with uncontrolled amounts of zero-variable-cost energy.

Increased solar PV penetration has a variety of impacts on wholesale market prices, as we have just seen. It is noteworthy, however, that as a result of basic supply-and-demand dynamics, solar capacity systematically reduces electricity prices during the very hours when solar generators produce the most electricity.[xv] Beyond low levels of penetration, an increasing solar contribution results in lower average revenues per kW of installed solar capacity. For this reason, even if solar generation becomes profitable without subsidies at low levels of penetration, there is a system-dependent threshold of installed PV capacity beyond which adding further solar generators would no longer be profitable.

Beyond low levels of penetration, an increasing solar contribution results in lower average revenues per kW of installed solar capacity.

Figure 8.11 depicts the effect of increasing solar PV penetration on average revenues per unit of solar energy produced. Since solar energy is produced in periods of relatively high demand, the prices perceived by owners of solar generation are initially high in comparison to the average system price. However, as net load

Figure 8.11 Average Market Prices and Average Prices as Perceived by Owners of Solar Generation



[xv] We have seen how prices may increase as a consequence of incremental cycling-related costs. Note that these prices occur during hours when solar resources are not available. Therefore, solar PV cannot benefit from this effect on prices.

diminishes with increasing solar production, market prices can fall rapidly during these hours.[xvi] At high levels of penetration, solar plants will produce during many zero-price hours. The figure can also be seen from a different perspective. By comparing annual average solar production costs (in $/MWh, where these production costs include investment plus operating costs) to annual per-MWh plant revenues, it is possible to estimate the amount of solar capacity (in GW) that would be naturally installed in an open, competitive market.

At high levels of penetration, solar plants will produce during many zero-price hours.

Role of Hydro Resources in Short-Term Operation

As we show next, there are valuable synergies in the joint availability of dispatchable hydro resources along with the non-dispatchable solar PV resources. For instance, the limited but dispatchable energy from flexible hydro resources (as from any other type of stored energy) generally makes it possible to reduce the net peak load that would otherwise occur around sunset. However, these synergies are obviously conditioned by the maximum output available from hydro generators and by the amount of energy that can be stored in reservoirs.

FINDING

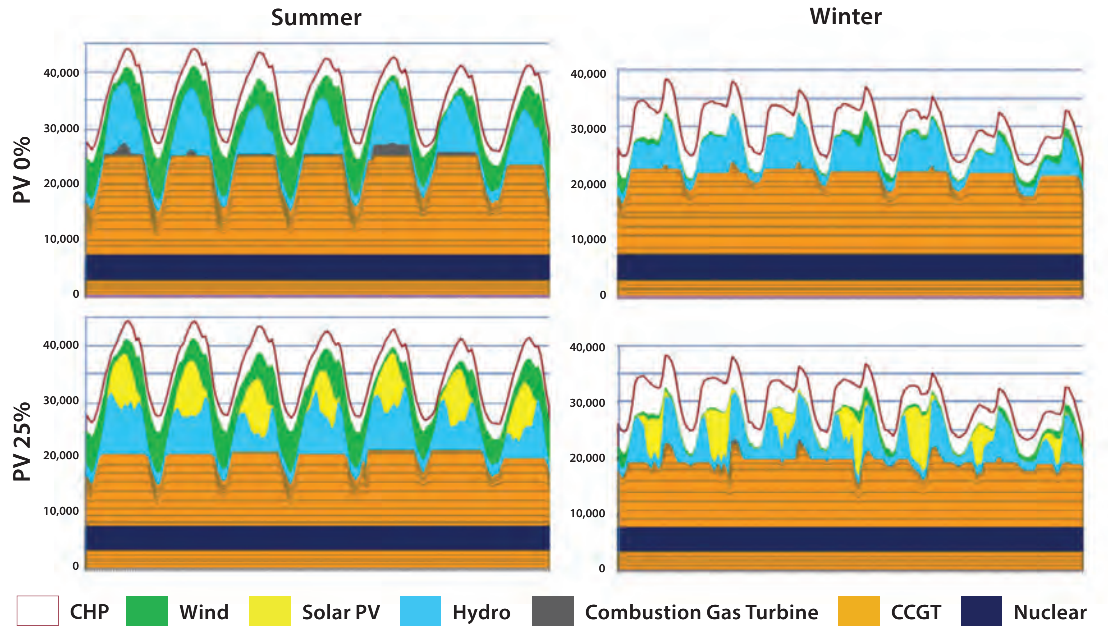
Even if solar PV generation becomes cost competitive at low levels of penetration, revenues per kW of installed capacity will decline as solar penetration increases until a breakeven point is reached, beyond which further investment in solar PV would be unprofitable.

In our simulation of a California-like system, the baseline scenario (with no PV contribution) shown in Figure 8.12 clearly illustrates the characteristic peak shaving dispatch of hydro plants. Net peak loads are not always completely covered by hydro generation because these plants have maximum outputs. Absent these output limits, access to hydro resources would make it possible to completely flatten net peak loads.

Hydro dispatch during the summer and winter weeks in the 25% PV scenario shown in Figure 8.12 helps illustrate what the joint availability of non-dispatchable solar and dispatchable hydro can and cannot achieve. We begin by focusing on the summer week, when the positive synergy between both technologies is easily observed.

[xvi]See Hirth[14] for further evidence supporting this argument.

Figure 8.12 Operational Impact of Hydro Resources in the California-Like System



Hydro units can be dispatched in such a way that the resulting net peak load is reduced by the combination of hydro and solar generation. That is, during this week, solar seems to "add" energy and maximum output to the hydro dispatch. This enhanced peak shaving further displaces the most expensive variable cost units (merit order effect) while also reducing cycling requirements for conventional generators.[xvii]

FINDING

Positive synergies can be achieved by jointly coordinating hydro and solar production in ways that help reduce net peak loads and cycling requirements for thermal generators.

However, optimal peak shaving is only possible when dispatch is not constrained by limits on the maximum output of hydro plants. This constraint can be illustrated using simulation results for some winter weeks. In the baseline scenario, we see that limits on hydro output leave the system with a net demand peak in the daily peak period. In this case, adding production from solar generators outside the peak period cannot be used to reduce net demand peaks. Coordinating solar and hydro resources in the winter, while still possible, is therefore less effective than coordinating these resources in the summer.

Although not shown in the figure, maximum power production from hydro facilities in the scenarios with installed PV capacity above 15 GW no longer allows for complete peak shaving in the summer. This results in a net load situation analogous to that described for winter.

[xvii] The higher the share of high-variable-cost units, such as diesel generators or gas turbines, the larger the savings that can be derived from this improved peak shaving capability.

8.4 LONG-TERM IMPACTS OF SOLAR PV ON TECHNOLOGY MIX, OPERATION, COSTS, AND PRICES

Analyzing the long-term impacts of a larger solar presence in the electricity generation mix requires adding a further dimension to the previous analysis: potential changes in the technology mix in response to the growing role of intermittent generators. As above, each simulation treats the level of PV capacity as given, regardless of whether revenues to PV generators would cover their costs. However, we do show (in Figure 8.23) the break-even level of solar PV costs per watt installed, given the revenues that PV facilities could expect to generate based on wholesale market energy prices.

A large-scale expansion of VER capacity will condition to a large extent the expansion of other generation technologies because of the effects of a large VER presence on conventional plants' operating regimes and therefore on system-wide production costs and prices.

A large-scale expansion of VER capacity will condition to a large extent the expansion of other generation technologies.

The goal of the simulation discussed in this section is to assess how changes in the generation mix in response to the increased penetration of solar and other VER technologies can affect the economics of electricity systems and the way they function. In contrast to the simulations described in the previous section, we recalculated the optimal non-solar generation mix for each scenario modeled in this portion of the analysis. Thus, the impacts calculated for different levels of solar penetration are driven not only by changes in system operation, but also — and more importantly — by changes in the generation mix.

Specifically, we find that three different but interrelated effects account for the long-term impact of increased solar PV penetration on electric power systems: (1) the merit order effect, (2) changes in cycling requirements for thermal plants, and (3) changes in the mix of generation technologies.

To examine long-term impacts, we assume that, consistent with current plant retirement plans, a significant portion of today's installed capacity will be decommissioned by 2030. Appendix F identifies the power plants that are assumed to still be operating in 2030 in our analysis.

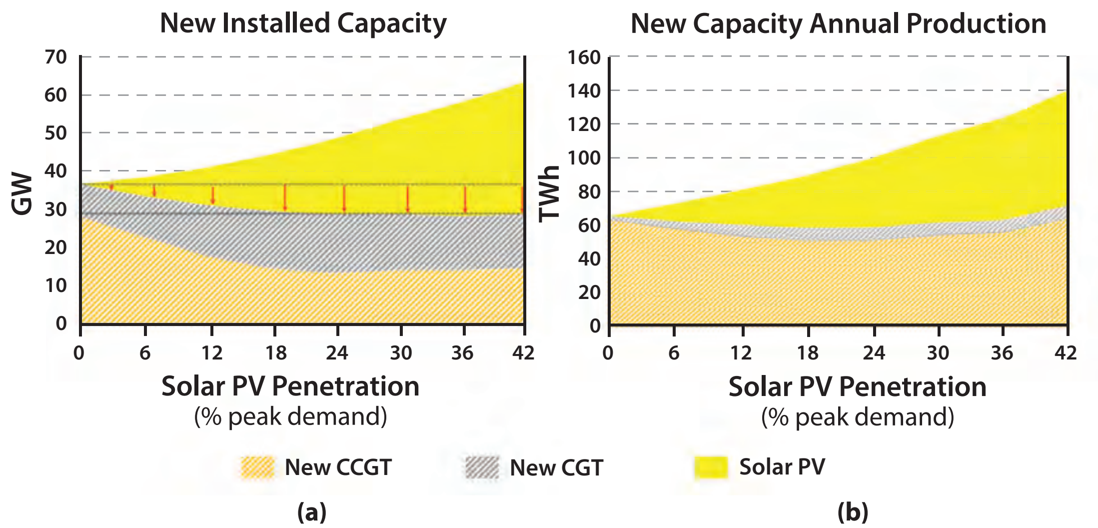
Plant decommissioning creates a deficit in generating capacity that needs to be covered by new investments. Therefore, we first analyze the technologies that can be expected to cover that gap. Afterwards, we examine the resulting market outcomes.

Impacts on Capacity Expansion and Operation

Figure 8.13a shows how the optimal mix of capacity investments in the ERCOT-like system changes at higher levels of solar penetration. CCGT and combustion gas turbine (CGT) technologies constitute the only new capacity installments.[xviii] Figure 8.13b charts annual production from these new investments. It is clear that CGT plants have low utilization factors (these units are mainly used to serve peak demand in the summer).

[xviii] No new coal plants are added in any scenario because the installed capacity of this technology is already higher than optimal.

Figure 8.13 Evolution of Installed Capacity and Annual Production by Technology (ERCOT-Like System)



A noteworthy finding from the figure is that total requirements for new thermal generating capacity decline when low levels of solar capacity are introduced. This reduction (marked with red arrows in Figure 8.13a) reflects the capacity value of solar PV; beyond a certain point it clearly reaches a saturation level due to solar PV's limited ability to reduce the system's net peak load.

FINDING

Hydro production increases the capacity value of solar generators at low levels of PV penetration.

The Role of Existing Hydro Resources in the Long-Term Expansion Problem (California-like System)

We also examined the evolution of the generation mix assuming a much larger role for solar PV[xix] in the more flexible California-like system (Figure 8.14). Several relevant differences from the ERCOT case are worth highlighting:

- In the California context, the capacity value of solar PV is enhanced at low levels of penetration because of the flexible hydro resources available in the system. Figure 8.15 shows the contribution of solar PV in terms of reducing new thermal capacity requirements in both systems in a magnified form for quick comparison.
- The flexibility of hydro plants dramatically reduces the need for CGT peaking units, which have higher operation costs than CCGT plants.

[xix]Only new thermal investments are evaluated; hydro capacity is assumed to remain constant.

Figure 8.14 Evolution of Installed Capacity and Corresponding Annual Energy Production (California-Like System)

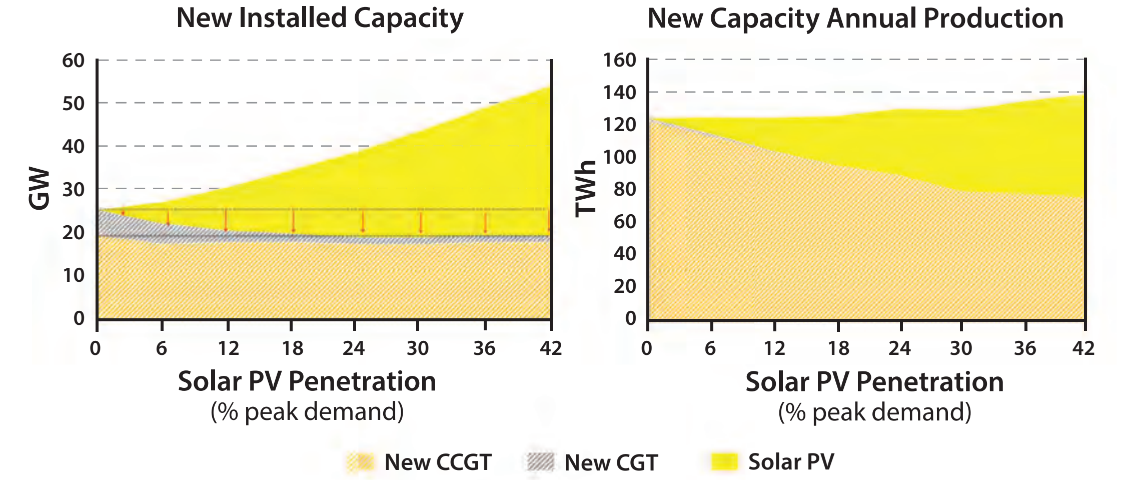
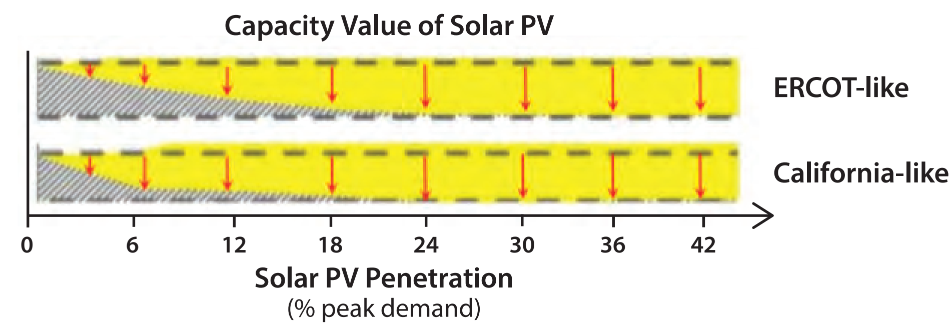


Figure 8.15 Capacity Value of Solar PV in the ERCOT and California Systems



Impacts on Long-Term Production Costs

Figure 8.16 shows the evolution of total long-term production costs (including annualized capital costs) for thermal generators as solar PV penetration increases in the ERCOT-like system. Again, although production costs decrease at higher levels of solar penetration, the rate at which they decrease also slows down.

Impacts on Prices

Figure 8.17 presents average wholesale prices in the ERCOT-like system. It is clear that these results are quite different from those obtained in the previous section, when we did not consider that the generation mix could be adapted in response to increased solar penetration. Solar penetration increases the need for low-capital-cost CGT plants. These CGT plants

Figure 8.16 Changes in Long-Term (Thermal) Production Costs as a Consequence of Solar PV Penetration (ERCOT-Like System)

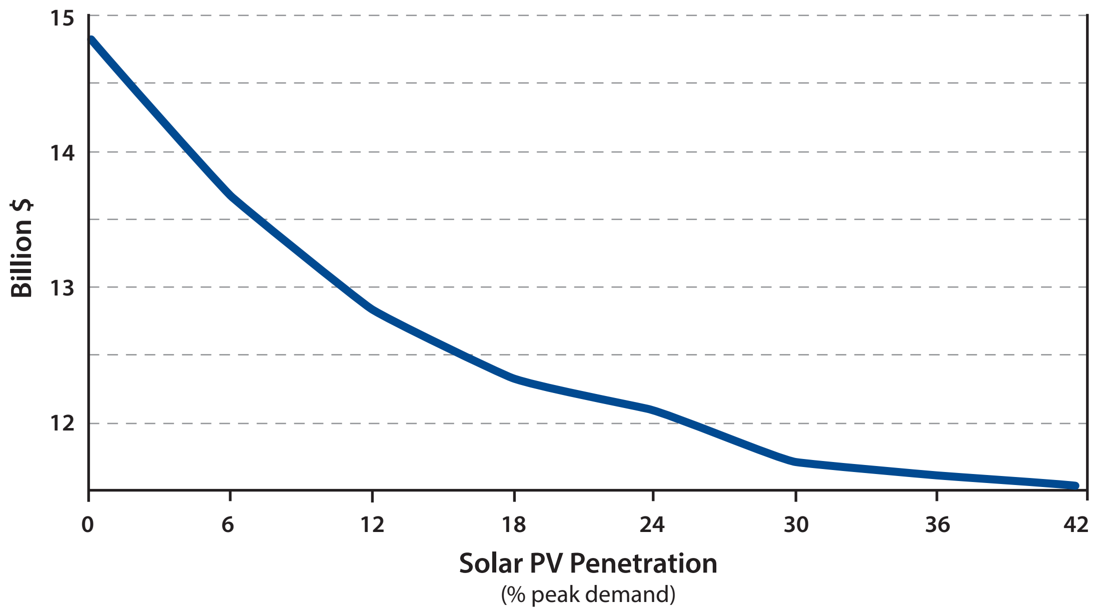
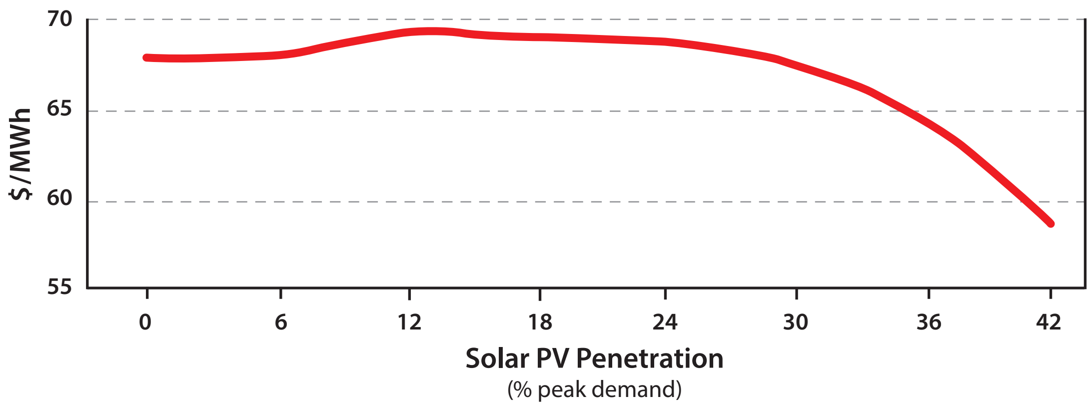


Figure 8.17 Evolution of Average Wholesale Market Prices



produce mainly during peak hours, where they obtain a higher price than that found in the baseline scenario with no PV.[xx] This effect, coupled with an increase in cycling requirements, tends to compensate for the merit order effect. At very high levels of penetration, the merit order effect weighs more heavily in the final results, and average prices decrease.

Despite a predicted decline in average prices as solar penetration increases, the model calls for some investment in CCGT and CGT plants, meaning that even in the high solar penetration scenarios these technologies are still financially viable. One of the reasons is that these plants, because they operate as peaking units, receive above-average prices for their output.

[xx]A larger amount of CGT installed capacity (even in the 0% solar scenario) leads to average prices that are significantly above those presented in the short-term analysis, where no CGT was installed.

FINDING

Despite a decline in average wholesale prices due to high solar PV penetration, it remains profitable over the long term to invest in thermal plants (mainly CCGT and CGT).

Impacts on Hourly Spot Market Prices

In the ERCOT-like system, prices are lower during shoulder and valley demand hours as a consequence of the merit order effect (see Figure 8.18). However, in high demand hours, prices tend to increase due to two effects: changes in the generation mix (higher CGT utilization, which has higher variable costs) and increased cycling of thermal plants.

Price-duration curves corresponding to 3,500 hours of higher demand in the California-like system are shown in Figure 8.19. There is no systematic increase in prices during these higher demand periods because, as previously discussed, the presence of hydro capacity in this system prevents the installation of CGT. An increase in prices during the 250 hours of highest net demand reflects the effect of increased thermal plant cycling.

Additionally, although this result is not shown in the figure, it is worth noting that solar PV depresses prices in the lower demand hours. This leads to a total of 2,927 hours with zero prices when installed solar capacity reaches 35 GW (prices are never zero in the case without solar PV).

Figure 8.18 Price-Duration Curves for Two Scenarios of Solar Penetration (ERCOT-Like System)

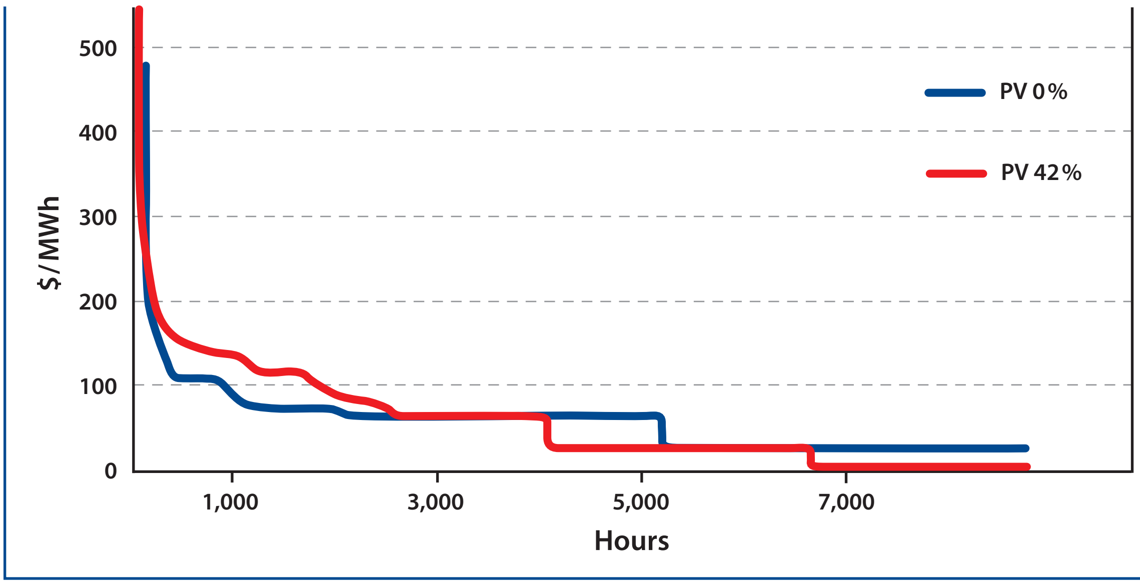
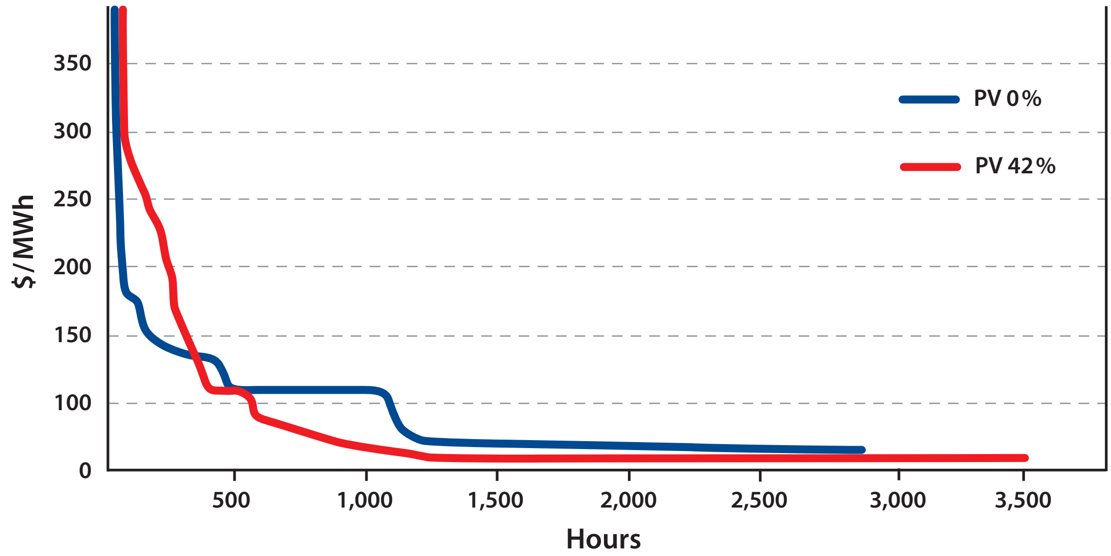


Figure 8.19 Price-Duration Curves for Two Levels of PV Penetration (California-Like System)



Effect of Production-Based Regulatory Support Schemes for VERs

The impact of subsidies mainly affects inflexible technologies (coal), and also requires new investments (mainly in CCGT capacity) to cover the gap left by coal.

In the short term, the distorting market effects of a fixed $/kWh production-based support mechanism for solar generators and other VERs will obviously depend on the level of the incentive itself. If the incentive is large enough, all renewable energy production will be put on the market. This therefore reduces the amount of renewable output that would be otherwise curtailed for economic reasons (i.e., to minimize total operation plus investment costs at a given level of solar PV penetration) and leads to more inefficient (and costly) operation of the system in the short term.[xxi]

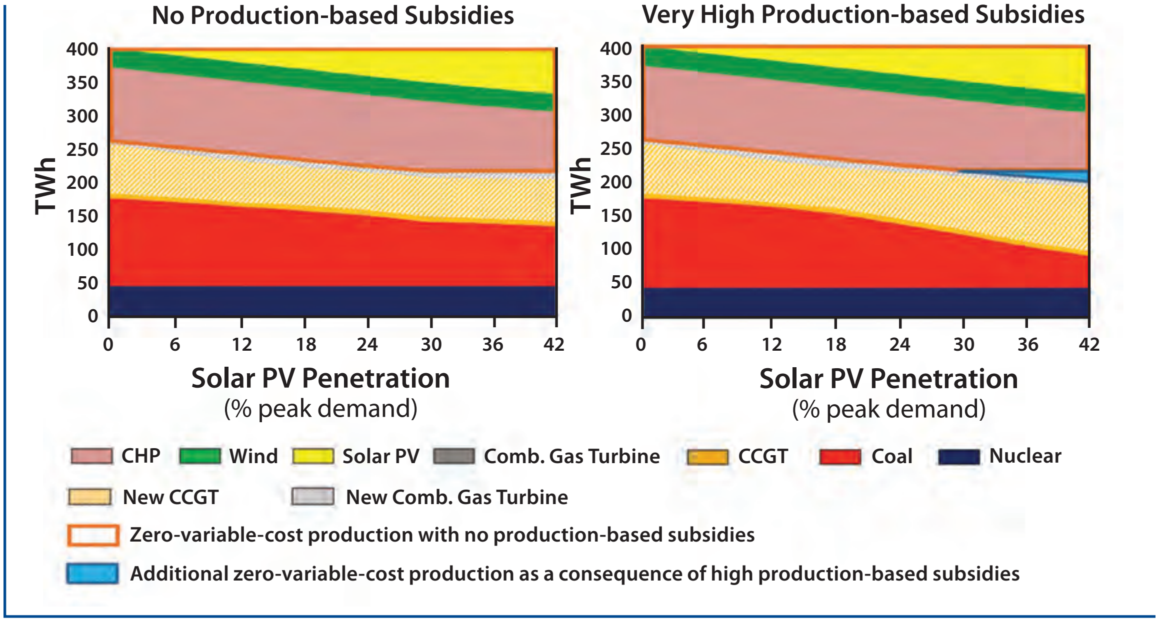
Figure 8.20 shows annual production in the ERCOT-like system for both extreme cases: the case with no support mechanism (Figure 8.20a) and the case with a very high per-kWh production subsidy (Figure 8.20b). The impact of subsidies mainly affects inflexible technologies (coal), and also requires new investments (mainly in CCGT capacity) to cover the gap left by coal. It is noteworthy that forcing a small amount of production that should have been economically curtailed (the area in solid blue), affects a much larger quantity of coal production.

FINDING

At high levels of solar PV penetration, production subsidies lead to short-term inefficiencies in system operation and changes in the generation mix.

[xxi]As discussed in Chapter 9, a $/kWh subsidy can be designed in ways that avoid such distortions. One alternative is to give an incentive that is proportional to market price, which would yield zero returns whenever the price is zero. Another approach would be to prohibit solar generators from bidding negative prices.

Figure 8.20 Annual Production by Technology Type with and without Solar Production Subsidies



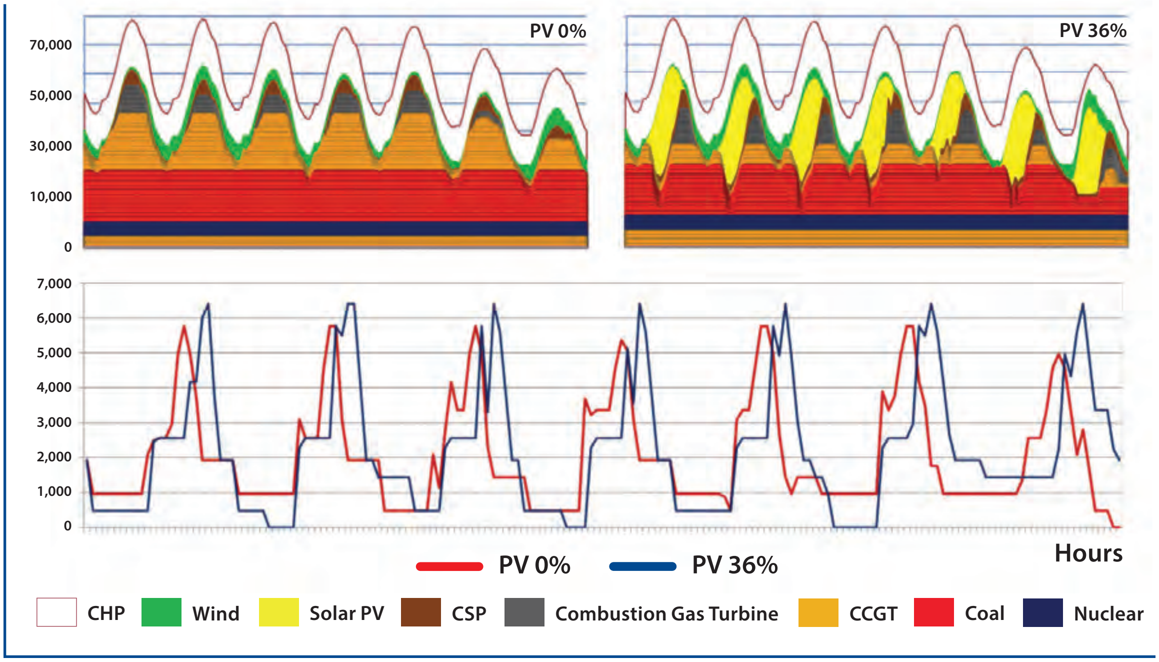
8.5 CONCENTRATED SOLAR POWER WITH STORAGE CAPABILITY

As discussed in Chapters 3 and 5, concentrated solar power (CSP) thermal plants can easily add (thermal) energy storage. Indeed, designing CSP plants to allow for energy storage typically lowers short-term generation costs by permitting more efficient operations and by enabling continued power output after sunset. Adding CSP facilities with thermal storage or other grid-level storage could aid the integration of solar PV. Roughly speaking, the addition of energy storage serves two potential uses:

- Energy storage can be used to increase the solar contribution during net peak load periods. Qualitatively, this use of stored energy is analogous to the use of hydro plants. The only difference is that, because of technical limitations, it may be more difficult to use thermal energy storage in CSP plants to produce electricity during net peak loads that occur before sunrise (Figure 8.21 shows a net load profile for high and low levels of PV penetration). To use stored energy to supply those peaks, CSP plants would need to be capable of retaining energy for the following day.

- The other alternative is to use stored thermal energy in CSP plants to produce throughout the night and during the early morning. Though prices are not usually high during the night and early morning, this approach has advantages both in terms of preventing the thermal storage fluid from solidifying (in the case of molten salts, for instance) and in terms of avoiding the need to stop and then re-start the turbine a few hours later.

Figure 8.21 Dispatch of CSP with Storage Capability in Two PV Penetration Scenarios



Depending on prices and technical conditions, stored energy from CSP plants could be used either way.

Figure 8.21 shows the simulated dispatch of CSP with thermal energy storage (TES) for two extreme scenarios: a scenario with no solar PV and a scenario with 30 GW of installed solar PV. The lower section of the chart compares the behavior of the CSP plant in both scenarios. In particular, the figure shows how larger amounts of stored CSP energy are available to supply peak loads in the scenario with high levels of PV penetration. Note that these model results are based on a predefined solar profile and on a set of assumptions concerning the most relevant technical characteristics of the CSP plant, including solar field thermal power, TES capacity (4 hours of storage), steam turbine minimum and maximum generation levels (we assume the minimum is one-third of the maximum), start-up energy requirements, and other start-up related costs. See Denholm[15] for a detailed description of the meaning of these parameters.

8.6 THE ROLE OF ENERGY STORAGE

At a wholesale level, the large-scale deployment of solar PV poses two major challenges: it results in lower net load valleys and produces narrower and steeper peak periods. As discussed in previous sections, these changes in the traditional load profile lead to an increase in cycling requirements for existing thermal plants and also to higher peak capacity requirements (because peak capacity is usually provided by units with high variable operating costs, this results in higher prices during peak periods when these units are producing).

Hydro resources can help deal with new net peak load periods in high PV penetration scenarios, but they do not help solve the problem created by lower load valleys. Technologies that offer energy storage capability can help to deal with both issues. Indeed, storage can aid the integration of larger amounts of solar PV in a free competitive market context by increasing the market remuneration for solar generation in low net load periods (when solar PV production is usually at a maximum).

We do not discuss the economics of different energy storage alternatives. Rather we focus on the benefits that storage provides, first from the perspective of the whole system, and second from the point of view of solar generators. These benefits can be achieved by introducing any technology that is capable of shifting net load from peak periods to valley periods (for example, load shifting can also be accomplished with demand side management).

Storage technologies take advantage of low prices during valley hours to store energy that can later be used to produce electricity during peak load hours. Figure 8.22 shows simulation results for a scenario in which some daily energy storage facilities (e.g. pumped hydro stations) are added to the ERCOT-like model system. The roundtrip efficiency for producing electricity from these storage facilities is assumed to be 0.7.[xxii] The figure shows results for four cases corresponding to different levels of maximum daily energy storage; specifically, 20, 40, 60, and 80 GWh.[xxiii] Figure 8.22 shows the resulting dispatch of different generation resources, including stored energy, during a typical summer week. The figure shows how valley demands increase, helping some units produce at higher output levels and also reducing cycling requirements. At the same time, some CGT production is avoided during peak net load periods.

Energy storage thus has two major effects on prices. It increases prices during demand valleys (because valley demand increases) and it reduces prices during peak demand periods. In light of our earlier observation that as, solar penetration increases, solar PV does not produce during peak net load hours, the most significant price effect of energy storage from the point of view of solar PV generators is an increase in prices during valley periods.

FINDING

At high levels of solar PV penetration, the addition of energy storage facilities benefits solar PV owners by increasing wholesale prices during load valleys and thereby increasing the market remuneration PV owners receive for electricity delivered during these periods.

[xxii] Roundtrip efficiency represents the relationship between the electricity generated divided by the electricity consumed by the storage facility.

[xxiii] Given that average daily electricity consumption in ERCOT totals 1,100 GWh, 20, 40, 60, and 80 GWh of production using stored energy corresponds to about 1.8% , 3.6% , 5.4%, and 7.2% of overall system requirements.

Figure 8.22 Impact of Energy Storage on the Hourly Dispatch of Different Generation Resources

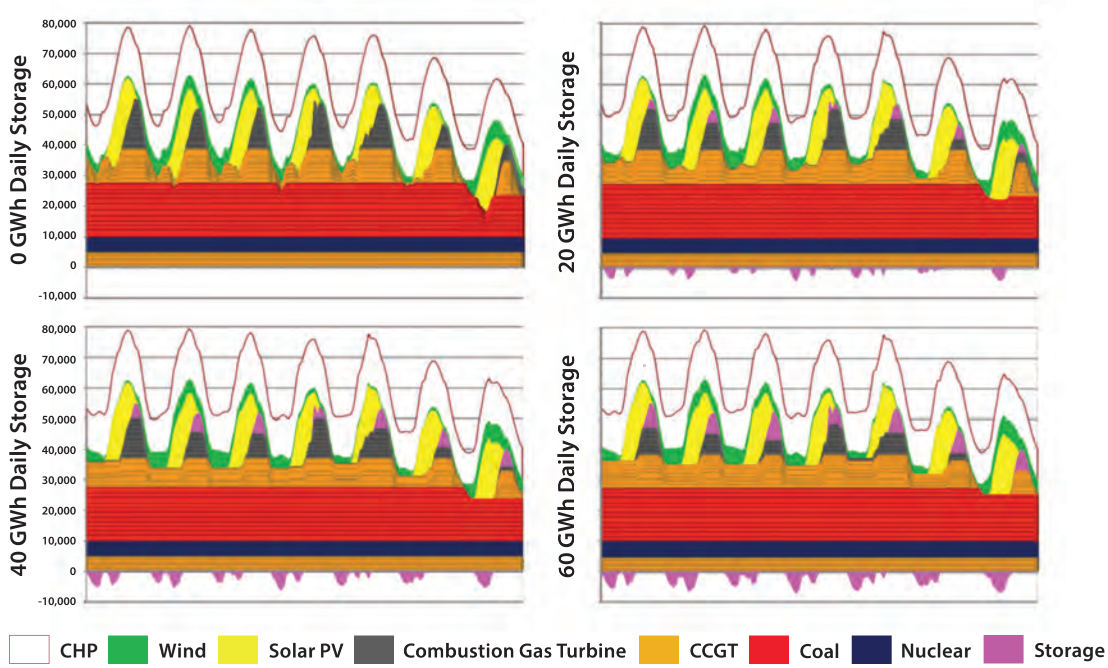
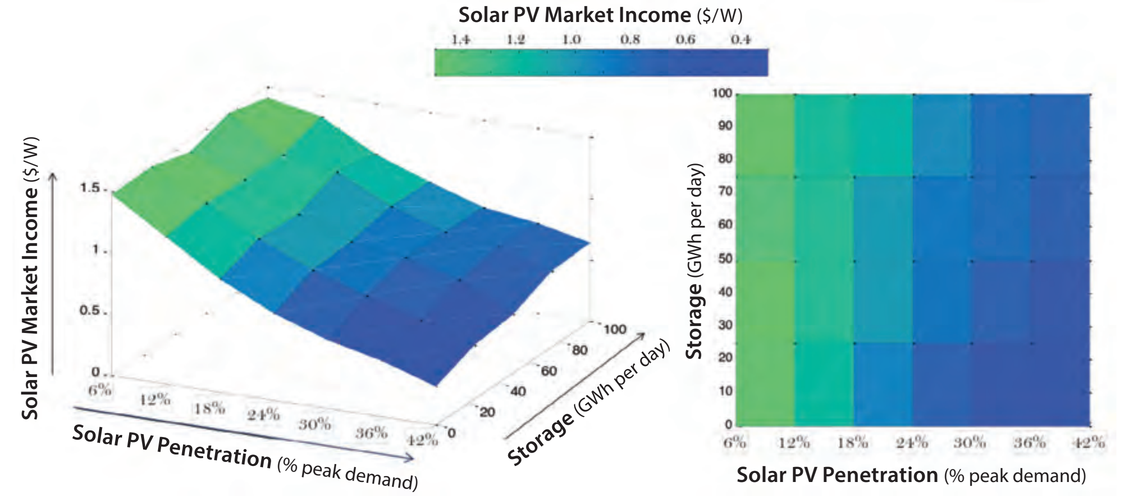


Figure 8.23 shows total revenues from solar PV production (per installed watt) at wholesale energy market prices, for each combination of solar PV penetration level and daily energy storage capability. This result can also be interpreted as the break-even cost of solar PV, at wholesale market prices, for each combination. Except for very low levels of PV penetration, the larger the quantity of added energy storage capability, the higher the revenues generated by PV plants and therefore the higher the profitability of PV investments at any level.

Except for very low levels of PV penetration, the larger the quantity of added energy storage capability, the higher the revenues generated by PV plants and therefore the higher the profitability of PV investments at any level.

Figure 8.23 Market Remuneration for Solar PV Production (in $/W) as a Function of PV Penetration and Energy Storage Capability



8.7 SUMMARY AND CONCLUSIONS

Our analysis of the expected economic impacts — at the wholesale market level — of having large amounts of solar generation fully integrated and competing in electricity markets points to several major findings. We conclude the chapter by summarizing these findings.

Interactions between Electricity Demand and Solar PV Production

Absent the ability to store energy for later use, solar PV generators — because they have zero variable operating costs — will most likely be dispatched whenever the sun is shining. Therefore, the load profile that is left to be supplied by other technologies can be determined by simply subtracting solar production (assuming this production is not subject to curtailment) from total load to yield a quantity that is usually referred to as *net load*. Analyzing net load helps to anticipate some of the major system impacts that would be expected to emerge at higher levels of solar PV deployment:

- The absolute net peak load, which is usually taken as a good proxy of the additional capacity needed on top of solar PV to supply system demand, can only be reduced when annual peak loads occur during the day.[xxiv] Even if this is the case, the reduction in absolute net peak load is very limited and does not continue to grow at higher levels of solar PV penetration.

- The daily minimum net valley load value can decrease for high levels of solar penetration. This can be a problem for thermal plants that try to avoid shutting down by producing at the minimum level of output technically required to maintain stable operation during valley periods.

[xxiv]This is the usual case in most regions of the United States, where annual peak loads are driven by summer air-conditioning loads. However, in regions where system demand is dominated by winter loads, solar PV will not reduce annual demand peaks because these peaks tend to occur after sunset, when no solar production is available.

- Low levels of solar PV penetration reduce net load ramps (the hourly increment or decrement of net energy demanded). At higher levels of penetration, however, ramping loads usually increase.

Main Short-Term Impacts of Solar PV on System Operation

In the short run, a large increase in solar PV production will reduce generation from plants with the highest variable costs, while also increasing cycling requirements for thermal plants. In terms of cost (and price) impacts, these two changes act in opposite directions: reduced generation from high-variable-cost units tends to reduce costs and prices, while greater cycling requirements tend to increase cost and prices. Which effect is more pronounced depends strongly on the existing generation mix. If the existing mix is relatively flexible, cycling effects will be less relevant. In particular, these effects can be significantly alleviated when the system has access to significant hydro resources or energy storage facilities. Although not analyzed in this chapter, demand response and strong interconnections with neighboring power systems are also known to have similarly mitigating effects on cycling requirements.

It is also worth noting that in purely thermal systems, the narrowing of net demand peaks implies that a number of units will need to start up to produce for a very small number of hours. This will have a material impact on prices, which will increase in these periods. Higher levels of solar PV deployment will generally reduce the profitability of pre-existing generation investments.

Main Long-Term Impacts of Solar PV on System Operation

In the long term, a growing solar PV presence will force the overall generation mix to adapt so as to better cope with increased cycling requirements. As a general rule, and in the absence of highly flexible generation options (e.g., hydro or storage), increased cycling needs coupled with a reduction in the utilization of thermal plants will prompt investment in more flexible peaking units with lower capital costs. The availability of flexible hydro resources can soften these short-term impacts, reducing the need for peaking units (in favor of more installed capacity of CCGTs rather than CGTs, for example).

Higher levels of solar PV deployment will generally reduce the profitability of pre-existing generation investments.

Solar PV's contribution to reducing system-wide capacity needs (as reflected in so-called capacity value or capacity credit) is strongly related to its ability to reduce annual net peak load. Our analysis finds that solar PV does not significantly reduce annual net peak load in otherwise purely thermal systems. In addition, we find that once PV is deployed on a large scale, further additions of installed PV capacity have very little effect on thermal capacity requirements. In this respect, the presence of hydro resources can slightly enhance the capacity value of solar resources.

Main Impacts of Solar PV on Market Prices

In purely thermal systems, the presence of large-scale solar PV — besides increasing short-term price volatility — tends first and foremost to reduce average market prices in general. At the same time, solar PV tends to increase peak prices in peak net load periods, which tend to occur around sunset in systems with a high penetration of PV resources. In systems with substantial hydro capacity, impacts on price volatility and the latter effect on peak net load prices are less relevant.

In purely thermal systems, the presence of large-scale solar PV — besides increasing short-term price volatility — tends first and foremost to reduce average market prices in general.

It is worth noting that price reductions from solar PV production are systematically most significant during the same hours when solar generators deliver maximum output. As a consequence, higher levels of solar penetration lead to lower revenues per kW of installed solar capacity. For this reason, at any given per kW installation cost of solar PV, there is a system-dependent threshold or limit beyond which adding further increments of PV capacity will not break even from a cost perspective.

At any given per kW installation cost of solar PV, there is a system-dependent threshold or limit beyond which adding further increments of PV capacity will not break even from a cost perspective.

If, in the long term, the generation mix adapts to higher levels of solar PV by installing more peaking capacity (this would be the expected trend in thermal systems), prices could increase during peak load periods as a consequence of higher variable costs to operate the new marginal technology. In any case, assuming the market is not affected by distorting regulatory intervention (e.g., price caps), our modeling exercise shows that no matter the level of PV penetration: (a) new capacity will be added to the system as needed to readjust the overall generation mix and (b) investors in new units will fully recover their investment costs.[xxv]

Production-based incentives lead to more inefficient (and costly) operation decisions in the short term and to a more inefficient generation mix in the long term.

Potential Inefficiencies Stemming from Production-Based Support Mechanisms

Production-based support mechanisms — such as per-kWh incentives — can reduce the (economic) curtailment of output from solar and other renewable generators and lead to inefficiently high levels of solar energy production in systems with large amounts of PV capacity. The distorting effect of such production-based support mechanisms on the short-term market obviously depends on the size of the incentive. If the incentive is large enough, all renewable energy production will be matched and scheduled in the market. Production-based incentives lead to more inefficient (and costly) operation decisions in the short term and to a more inefficient generation mix in the long term.

[xxv] In a properly functioning market, any unit that is needed to minimize long-term system costs should ideally represent a profitable investment — in other words, marginal prices should provide adequate incentives for needed capacity investments.

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