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Grid flexibility and storage required to achieve very high penetration of variable renewable electricity

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ABSTRACT

We examine the changes to the electric power system required to incorporate high penetration of variable wind and solar electricity generation in a transmission constrained grid. Simulations were performed in the Texas, US (ERCOT) grid where different mixes of wind, solar photovoltaic and concentrating solar power meet up to 80% of the electric demand. The primary constraints on incorporation of these sources at large scale are the limited time coincidence of the resource with normal electricity demand, combined with the limited flexibility of thermal generators to reduce output. An additional constraint in the ERCOT system is the current inability to exchange power with neighboring grids.

By themselves, these constraints would result in unusable renewable generation and increased costs. But a highly flexible system – with must-run baseload generators virtually eliminated – allows for penetrations of up to about 50% variable generation with curtailment rates of less than 10%. For penetration levels up to 80% of the system's electricity demand, keeping curtailments to less than 10% requires a combination of load shifting and storage equal to about one day of average demand.

1. Introduction

There are three main technology pathways for supplying large amounts of low-carbon electricity—nuclear, fossil with carbon capture and sequestration (CCS), and renewables. Each option has challenges—CCS and nuclear have problems of scale-up, and waste disposal (plus limits in their ability to perform load-following). Renewables, particularly wind and solar are challenged by the variability of the resource. While the "cost-optimal" solution may require all three (including dispatchable renewables such as hydropower, biomass, and geothermal) it is informative to examine the "limiting case" of a variable renewable-dominated scenario. This will provide insights into the changes to the grid required if powered mostly by variable sources.

In the US, the limits of wind and solar are not resource based—the wind and solar resource are significantly greater than the total electric demand (US DOE, 2008; Denholm and Margolis, 2008a). The primary technical challenge is the variability of the resource (sometimes referred to as intermittency) or the fact that the supply of variable renewable generation does not equal the demand for electricity during all hours of the year. Recent growth of renewables has prompted many integration studies, which in the US have examined the costs and impacts of deploying increasing amounts of wind and solar penetrations on the grid. Examples include the Eastern Wind Integration and Transmission Study (EnerNex, 2010), which examined the impacts of meeting up to 30% of the eastern US electricity demand from wind, and the Western Wind and Solar Integration Study which examined the impact of up to 35% wind and solar on a part of the western US grid (GE Energy, 2010). A summary of wind integration practices and studies is provided by Ackermann et al. (2009), Corbus et al. (2009), and DeCesaro et al. (2009). These studies have found that these levels of variable generation (VG) can be accommodated by certain operational changes, such as greatly increasing the size of balancing areas and cooperation between utilities to maximize diversity of the wind resource and demand patterns. Technically, this requires substantial new transmission additions, but does not absolutely require large-scale deployment of certain enabling technologies such as energy storage to maintain reliability. These studies also demonstrate the increasing challenges to integration of wind energy that may result from the limited coincidence of wind energy supply and consumer demand patterns, combined with the inflexibility of conventional generators. At higher penetration of wind and solar, this combination results in potentially excess wind and solar generation, resulting in curtailed output and higher overall costs. However, the effects of variability at penetration beyond 30% in the US are not well studied, so the

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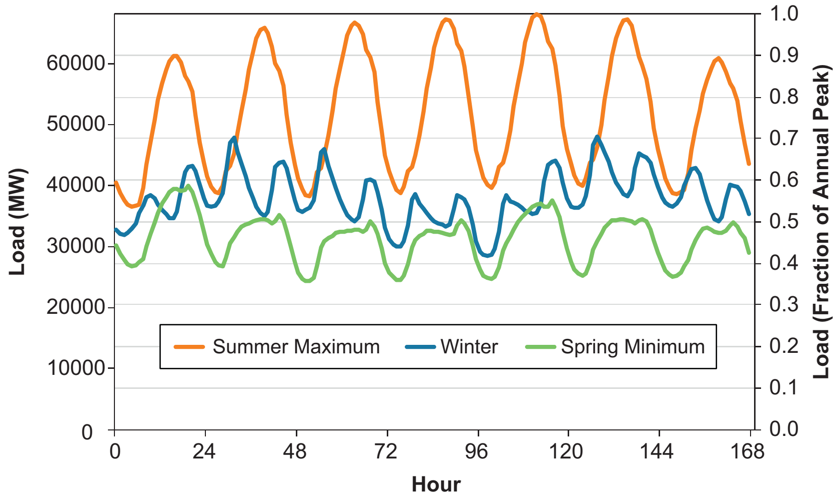

Fig. 1. Hourly loads from ERCOT in 2005.

need for flexibility and enabling technologies such as energy storage at extremely high penetration of VG are not well quantified.[1]

This analysis differs from wind integration studies that evaluate the technical feasibility, or operating costs of a small number of wind penetration scenarios, based on current or near future grid conditions and using detailed grid production simulations. Instead, it examines in general what changes to the grid would be necessary to accommodate extremely high penetration of variable renewables in terms of system flexibility, and the potential role of enabling technologies such as energy storage. This analysis is part of a much larger study by the US Department of Energy (Renewable Electricity Futures) to examine the system-level requirements of deriving the majority of the nation's electricity from renewable energy sources. The larger study examines the economic and technical impacts of various mixes of renewables across the entire US at a seasonal to hourly level.

The analysis in this study focuses on a single isolated region (the Texas grid in the US) and a mix of renewables dominated by solar and wind to examine a "limiting case" where the grid is dependent on variable renewables as opposed to dispatchable renewables such as biomass or geothermal. This report analyzes scenarios where VG provides up to 80% of the system's electricity, which is a somewhat arbitrary target, but also based on estimates that carbon reductions of about 80% will be required for climate stabilization, and corresponds to emissions reductions in recent proposed legislation (US EPA, 2010). This scenario will provide insight into the flexibility requirements, including energy storage, which may be needed in a grid dominated by variable renewable sources.

We begin by examining some general characteristics of electric power systems focusing on system flexibility, or the ability of conventional generators to vary output and respond the variability and uncertainty of the net load. We then provide a description of a tool (REFlex) that we developed to evaluate the interaction between variable generation and normal electricity demand patterns, considering the limitations of the flexibility of traditional electric generators. Next, we provide results of several simulations that estimate the amount of curtailed VG[2] in scenarios where VG provides up to 80% of the total electricity demand. Finally we examine the reduction in curtailment that results when enabling technologies such as energy storage are deployed.

2. Challenges of extremely high penetration of variable generation

2.1. Current operation

Reliable electric power system operation requires a mix of power plants that can respond to the constantly varying demand for electricity as well as provide operating reserves for contingencies. Fig. 1 illustrates an example demand pattern for three weeks for the Electric Reliability Council of Texas (ERCOT) grid during 2005 (see Section 3.1 for additional discussion of the ERCOT grid). This demand is met with three types of plants typically referred to as baseload (meeting the constant demand), intermediate load (meeting the daily variation in demand), and peaking (meeting the peak summertime demand).

In addition to meeting the predictable daily, weekly, and seasonal variation in demand, utilities must keep additional plants available to meet unforeseen increases in demand, losses of conventional plants and transmission lines, and other contingencies. This class of responsive reserves is often referred to as operating reserves and includes meeting frequency regulation (the ability to respond to small, random fluctuations around normal load), load-forecasting errors (the ability to respond to a greater or less than predicted change in demand), and contingencies (the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage) (NERC, 2009). Both frequency regulation and contingency reserves are among a larger class of services often referred to as ancillary services, which require units that can rapidly change output.

2.2. Impact of variable generation

Variable renewable generators (primarily wind, solar photovoltaics, and concentrating solar power when deployed without storage) are unlike conventional generators. They cannot be dispatched (except by curtailing output) and their output varies depending on local weather conditions, which are not completely predictable. Variable generators reduce the fuel (and associated

[1] Several European studies have examined higher penetrations, and found that the amount of wind curtailment, and need for technologies such as energy storage depend greatly on the mix of generators, access to spatially diverse resources and ability to share generation and load with a large interconnected network (Ackermann et al. 2009, Tuohy and O'Malley, 2009).

[2] From this point on, variable renewable generators will be referred to as variable generation (VG) following NERC (2009).

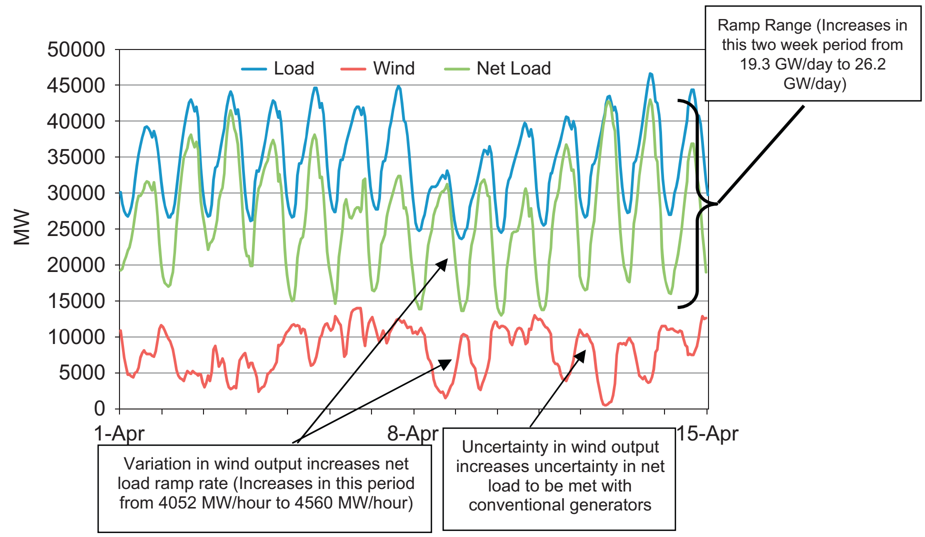

Fig. 2. Impact on net load from increased use of renewable energy.

emissions) from load-following and cycling units and in order to be of benefit, conventional generators used to meet the normal demand must be able to reduce output and accommodate wind and solar generation.

Fig. 2 illustrates a simplified framework for understanding the impacts of variable renewables, where VG reduces the net load met by conventional generators. In this figure, renewable generation is subtracted from the normal load, showing the "residual" or net load that the utility would need to meet with conventional sources.[3] There are four significant impacts that change how the system must be operated and affect costs. First is the increased need for frequency regulation, because wind can increase the short-term variability of the net load (not illustrated on the chart). Second is the increase in the ramping rate, or the speed at which load-following units must increase and decrease output. The third impact is the uncertainty in the wind resource and resulting net load. The final impact is the increase in overall ramping range – the difference between the daily minimum and maximum demand – and the associated reduction in minimum load which can force baseload generators to reduce output, and in some cases force the units to cycle off during periods of high VG output. Together, the increased variability and uncertainty of the net load requires a greater amount of flexibility and operating reserves in the system, with more ramping capability to meet both the predicted and unpredicted changes in net load.[4]

Previous wind integration studies in the US have focused primarily on the operational feasibility and integration costs due to the increased variability and uncertainty in net load where VG provides up to 30–35% of total demand. General approaches to address variability and uncertainty while maintaining reliability at these levels of penetrations are discussed by NERC (2009, 2010). At higher penetrations, a primary constraint becomes the simple coincidence of renewable energy supply and demand for electricity, combined with the operational limits on generators providing baseload power and operating reserves. This may present an economic upper limit on variable renewable penetration without the use of enabling technologies.

2.3. System flexibility

System flexibility can be described as the general characteristic of the ability of the aggregated set of generators to respond to the variation and uncertainty in net load. At extremely high penetration of VG, a key element of system flexibility is the ability of baseload generators, as well as generators providing operating reserves, to reduce output to very low levels while maintaining system reliability.

Fig. 3 illustrates this issue by providing the impacts of system flexibility and generator minimum load on accommodating VG. These two charts superimpose a spatially diverse set of simulated wind and solar data on load data from the same year (the data sets are discussed in detail in Section 3). In the first simulation (left chart), it is assumed that thermal generators are unable to cycle below 21 GW or 65% below the annual peak load of about 60 GW. In this case a mix of wind and solar provides 20% of the energy demand. However, 21% of the VG generation must be curtailed due to the minimum generation constraints caused by baseload units that are unable to cycle, or thermal units that cannot be turned off because they are providing operating reserves to accommodate the increased ramp rates and uncertainty of the net load. The right graph shows the result of increasing flexibility, allowing for a minimum load point of 13 GW. Curtailment has been reduced to less than 3%, and the same amount of variable renewables now provides about 25% of the system's annual energy.

Minimum generation constraints (and resulting wind curtailment) are already a real occurrence in the Danish power system, which has a large installed base of wind generation (Ackermann et al., 2009). 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 generation, which forces curtailment of wind energy production. It should be noted

[3] This figure uses ERCOT load data from 2005 along with 15 GW of spatially diverse simulated wind data from the same year. See Section 3 for more details about the data used.

[4] There are additional technical challenges associated with VG integration such as the potential decrease in mechanical inertia that helps maintain system frequency. This challenge is not well understood and could be mitigated by a variety of technologies including improved controls on wind generators, or other sources of real or virtual inertia that could include energy storage (Doherty et al., 2010).

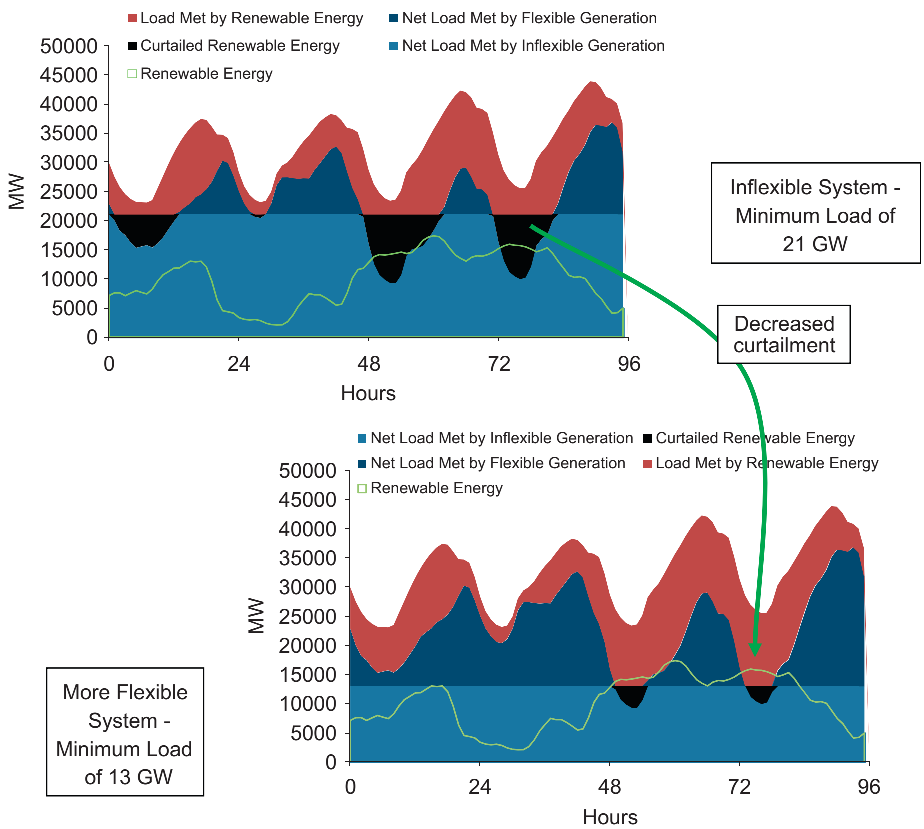

Fig. 3. Impact of system flexibility on curtailed energy.

that wind curtailment also occurs in the US grid, primarily due to transmission constraints (Fink et al., 2009). The best example is in Texas, where insufficient transmission from West Texas to load centers in East Texas resulted in curtailment of 17% of wind generation in 2009 (Wiser and Bolinger, 2010). This is fundamentally different from minimum generation related curtailment, which is the focus of this analysis and we assume that sufficient transmission capacity is added to avoid transmission related curtailment.

The minimum loading constraint and overall system flexibility largely depends 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. The flexibility of current systems can be difficult to assess, and is an area of active research (Denholm et al., 2010). In reality, the minimum load is not a hard constraint, but an economic issue based largely on the costs of thermal unit cycling, as well as the amount of operating reserves required, and the type of units providing those reserves. Instead of focusing on constraints in the current system, the focus of this analysis is to determine how flexible a system must be to accommodate up to 80% VG.

3. Simulation of high penetration cases using the REFlex model

To better understand the need for system flexibility, grid simulations were performed with the Renewable Energy Flexibility (REFlex) model (a modified version of the PVFlex model described in Denholm and Margolis, 2007a,b). REFlex is a reduced form dispatch model that compares VG supply with demand and calculates the fraction of load potentially met by VG considering flexibility constraints and curtailment. REFlex also can dispatch a variety of system flexibility options to determine the basic feasibility of matching RE supply with demand.

REFlex performs an hourly simulation and includes the electricity demand and the output from a variety of VG resources. The data are read into a series of Visual Basic for Applications (VBA) tools that compares VG output during each hour to the load that can be met by VG (equal to the load minus the minimum generation levels from conventional generators). If VG output exceeds this net system demand during any hour, then the excess VG output during this hour is curtailed (or may be placed into storage if available). As a reduced form dispatch model, REFlex does not commit individual thermal units based on generator operating constraints. Instead it evaluates the ability of an entire system to accommodate VG based on its aggregated system minimum generation level. This allows for a general understanding of the system flexibility needs of many different combination of VG, as opposed to a detailed technical and economic evaluation of any particular scenario.[5] The system minimum is an input to the model based on a fraction of system peak, representing the limits of both baseload generators and generators that must remain online to reliably meet the variability and uncertainty of the net load. This minimum load constraint can also be expressed more generally as the system's "flexibility factor," which is defined as the fraction below the annual peak to which conventional generators can cycle (Denholm and Margolis, 2007a,b). 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. In these simulations, the amount of must-run generation was based on fixed levels to examine sensitivity to different levels of system flexibility.

[5] Operational simulations (including stability and transmission analysis) and would be required to determine the actual feasibility of any individual scenario (Milligan et al., 2010). An evaluation of the substantial changes in electricity supply markets would also be needed to ensure the system flexibility required by these scenarios.

3.1. Load and utility system assumptions

This analysis simulated the Electric Reliability Council of Texas (ERCOT) system. Currently, 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, virtually all electric demand in ERCOT must be met with generators located within the ERCOT territory. ERCOT is the smallest of the three US grids, 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). For comparison, ERCOT's total electric demand in 2005 was between the demand of Spain (245 TWh) and the United Kingdom (350 TWh) (EIA, 2010). ERCOT makes for an interesting case study, because of its isolation, and significant potential use of variable renewables. It has good solar and wind resources, with technical potential that exceeds current electricity demand, including sufficient direct normal irradiance to deploy concentrating solar power. However, ERCOT has limited access to baseload or dispatchable renewables such as hydro or geothermal. This combination may require ERCOT to depend more on variable renewables than other parts of the US, and acts as a "limiting case" to evaluate the impacts of VG on an isolated grid.

In framing 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 VG 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 VG interacts with the system. ERCOT, like most of the US, is a summer peaking system, with seasonal demand patterns characterized in Fig. 1, and unlike many European systems which are winter peaking (ENTSO-E, 2008). While the load profile may change over decadal time scales due to changes in weather patterns, building technology, equipment, appliances, etc., these changes are hard to predict, so we assume the relationship between weather and electric demand remains constant in the base case. However we also evaluate the effect of load shifting as a sensitivity case.

We do not consider transmission constraints, and assume sufficient transmission capacity is constructed to access remote wind and concentrating solar power (CSP) resources in West Texas. We also did not consider the possible impacts of changes in T&D losses. Utility loads are measured at central locations so T&D losses then are considered part of the net load. Since wind and CSP generators may be further from loads than normal generators, it is likely that transmission losses for wind may be somewhat higher than average. Alternatively, much of the distributed solar PV generation will be deployed on rooftops or at load centers, reducing T&D losses. The net impact is difficult to assess so we assume that T&D loss rates for a VG dominated system are the same as for a conventional system.

Finally, we assume that ERCOT remains a single balancing authority, centrally dispatched to maximize the use of renewable energy, and electrically isolated. This is an overly restrictive assumption that in many ways presents a limiting case, as ERCOT already has some small interconnections with the other grids, and there are proposals to substantially increase these interconnections (TresAmigas, 2010). It is likely that a "cost-optimal" system would use transmission to exchange renewables with the Eastern and Western interconnects to share resources, reserves, and load.

3.2. RE data sources

Simulated wind data for 2005 and 2006 was obtained from AWS Truewinds (GE Energy, 2008). The data set includes a total of 76.8 GW of capacity, with an overall average capacity factor of 34.3%. A map of the wind resource areas, along with capacity and average capacity factor in each area is provided in Appendix A. Substantial new transmission capacity would be needed since much of Texas's best wind resources are in lightly populated areas in the west. Furthermore, several of the zones are actually outside the ERCOT territory. For additional discussion of the wind data, see GE Energy (2008).

For hourly PV production, solar data for 2005 and 2006 was derived from the updated National Solar Radiation Database (NSRDB) (NREL, 2007a,b; Wilcox and Marion, 2008). A total of 49 sites in ERCOT were used for the simulation, with a map and performance associated with each site provided in Appendix A. Solar insolation and temperature data was converted into hourly PV output using the Solar Advisor Model (SAM) (Gilman et al., 2008). We assume that PV will be distributed in a mix of rooftop and central systems (both fixed and 1-axis tracking) distributed in proportion to population. The distribution of orientation was based on an assumed mix of 50% central and 50% rooftop. Of the central PV, it was assumed that 25% is fixed (south facing , tilted at 25°), with the remainder 1-axis tracking. The rooftop systems are assumed to be a mix of flat and fixed tilt systems with a variety of orientations based on Denholm and Margolis (2008b). It is not designed to be the optimal mix and should be viewed as being illustrative rather than prescriptive.

For CSP, SAM uses the direct normal irradiance (DNI) to calculate the hourly electrical output of a wet-cooled trough plant (Turchi, 2010). In the base case we assume no storage. A total of 145 sites in west Texas (where DNI exceeds 6.1 kWh/m^2/day and capacity factor exceeds 22%) were used. These sites, along with the solar resource are provided in Appendix A. As with wind, some of the best resources are outside of ERCOT, and we assume that dedicated transmission is constructed to access these resources.

4. Result—high VG scenarios without energy storage

4.1. Impacts of system flexibility

We first evaluate scenarios that examine the impact of system flexibility, or the ability of conventional generators to accommodate the variable nature of wind and solar generation. This initial scenario does not consider the role of load or supply shifting (via energy storage or other technologies), but does consider high levels of flexibility that will require supplying reserves with non-thermal generation such as demand response. The metrics evaluated include fraction of load met by VG, curtailment, and the corresponding increase in VG costs due to excessive VG curtailment.

Figs. 4–6 provide a framework for evaluating the feasibility and potential costs of these high-penetration scenarios. This initial simulation is a wind-only scenario, using the complete wind data set, and based on the system assumptions described in Section 3.1. Fig. 4 shows the total VG curtailment as a function of the fraction of the system's energy derived from usable (non-curtailed) VG. Three curves are shown for various flexibility factors – 80%, 90%, and 100%, which correspond to minimum generation points of 12, 6, and 0 GW.

The results in Fig. 4 follows many previous wind integration studies indicating fairly low levels of wind curtailment at penetrations up to 30%, assuming sufficient generator flexibility. Beyond these levels, the curtailment rate increases sharply, especially considering that a 100% flexible system is well beyond what is currently achievable given the dependence of the existing system on relatively inflexible baseload generators. Achieving 80% of the simulated system's electricity from wind generation only (and without storage) requires a system flexibility of close to 100%, and results in a curtailment rate of more than 43%. Due to

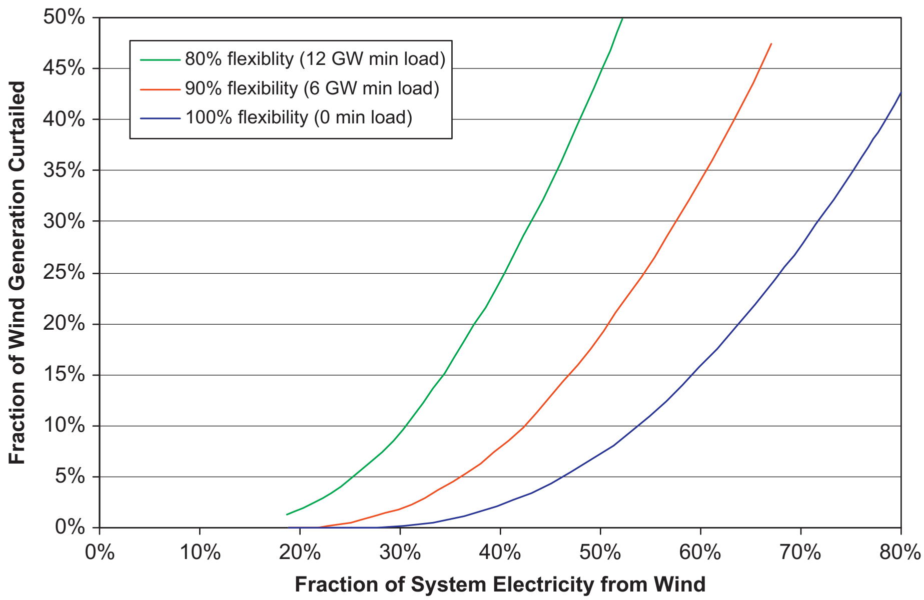

Fig. 4. Total curtailment as a function of usable wind energy penetration for different system flexibilities.

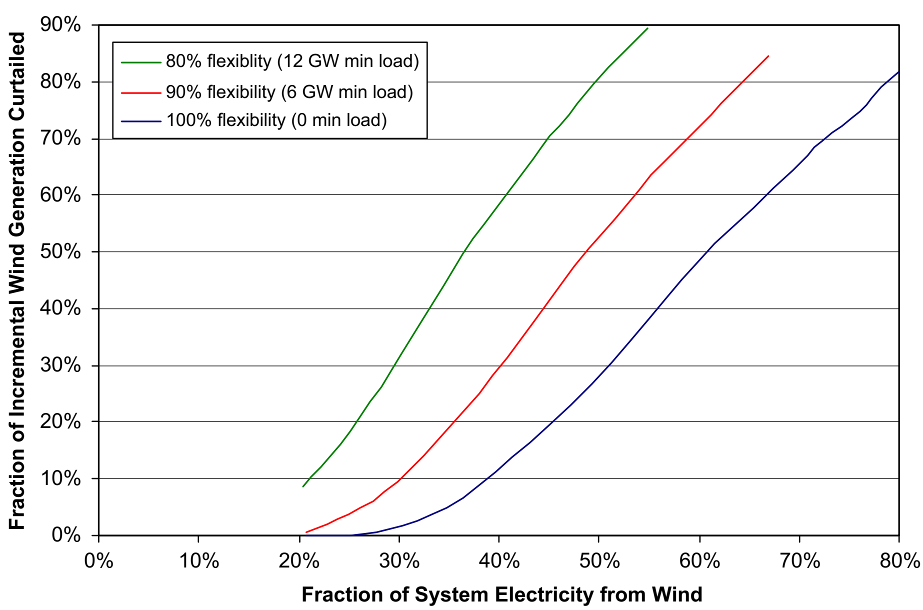

Fig. 5. Marginal curtailment as a function of usable wind energy penetration for different system flexibilities.

this high level of curtailment, the installed capacity of wind required to achieve 80% is about 140 GW, which exceeds the 77 GW of modeled wind output data. The actual wind resource in Texas is well over 1000 GW (NREL, 2007a), and this analysis assumes that the additional wind resource in ERCOT has the same temporal patterns as the modeled wind data set.

The curtailment rate at 80% penetration is probably beyond what is acceptable or cost-optimal. This concern can be emphasized by providing the marginal curtailment curves for the same data (and same flexibilities) in Fig. 5. In this curve, the curtailment rate is associated with each incremental unit of wind installed in the system. (As before, the energy penetration is defined as usable energy, subtracting out curtailed VG.) At 80% penetration, the incremental curtailment rate is over 80%, meaning that any additional wind will provide very little usable energy into the system.

At such high curtailment rates, this system is likely to be cost-prohibitive. As the curtailment rates increase, the effective capacity factor drops, resulting in substantially increased costs.[6] Fig. 6 illustrates how the marginal and average relative cost of electricity from wind changes as the level of wind penetration increases. The same data from Figs. 4 and 5 is translated into a relative cost of wind generation, measured as relative to a "base" cost of 1, i.e. the cost of electricity from wind without curtailment. The relative cost, equal to the inverse of (1-curtailment rate) is due only to curtailment and does not incorporate the cost of uncertainty or reserves typically classified as integration costs (Milligan and Kirby, 2009). There is a considerable difference between average and marginal costs, particularly at high penetration levels. For example, to achieve a 50% penetration level of wind in a 90% flexible system, the average cost of wind generation would be about 1.2 times the

[6] The levelized cost of an energy system is proportional to the inverse of the capacity factor.

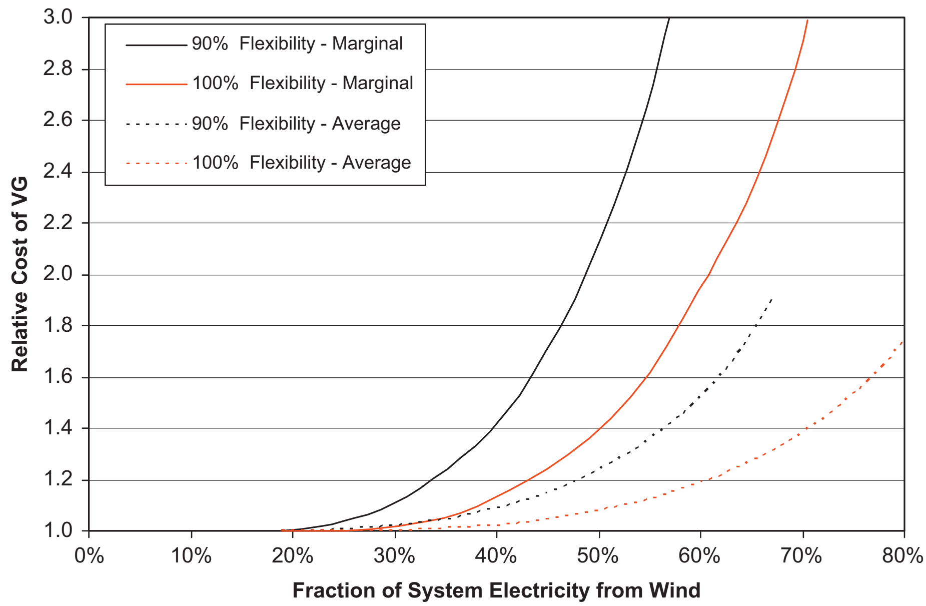

Fig. 6. Average and marginal relative cost of wind as a function of wind energy penetration due to increasing amounts of curtailment.

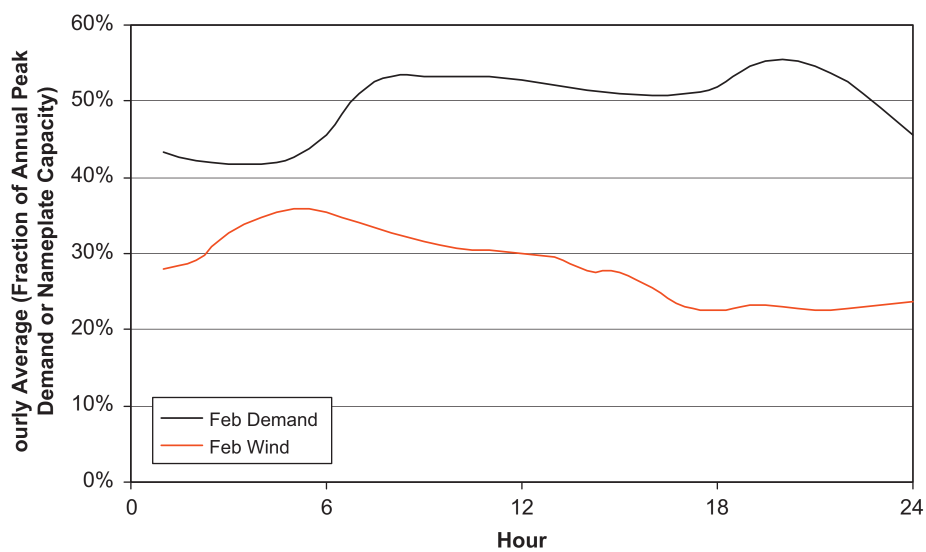

Fig. 7. Average daily wind output and electricity demand during February.

base cost. In other words, if the "base" cost of wind-generated electricity were 10 cents/kWh, the actual cost of *every* kWh of wind used in this system would be 12 cents/kWh in the 50% penetration/ 90% flexibility case. However, at the margin, the "last" unit of wind generation installed to meet the 50% penetration level would cost about two times the base cost, or 20 cents/kWh. At the 80% penetration level, the higher flexibility is required, and results in an average cost of wind at about 1.8 times the base cost, and the marginal cost for the last unit of wind installed to get to 80% would be over five times the base cost due to its high level of curtailment. (The effective capacity factor of this last unit of wind would be about 6%.) 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 VG penetration—especially considering market evaluation and rules for "allocation" of curtailment.

The sharply increasing curtailment rates (and corresponding costs) are due to the limited correlation of wind and load. Once the threshold of curtailment is met, an increasing fraction of additional wind occurs during those periods of curtailment. This is illustrated in Figs. 7 and 8 which show the seasonal and daily patterns of both wind and load. The figures show the average wind output (as a fraction of nameplate capacity) and the average demand (as a fraction of peak demand). The figures indicate that wind and demand tend to be anti-correlated, with wind peaking in the morning and demand peaking in the afternoon. These patterns of load/wind correlation are similar to those in much of the US, but not necessarily similar to those in Europe or locations (GE Energy, 2010; Holttinen et al., 2009). As a result, it is unclear how the results of this study can be more generally applied. These patterns also suggest a mix of wind and solar resources could improve the coincidence of VG and load due to solar's greater production during the middle of the day.

4.2. Impacts of wind/solar resource mix

Fig. 9 shows how the curtailment rates change with the addition of solar in a 100% flexibility (0 minimum load) scenario. The mix is shown based on relative fraction of solar and wind generation. As a

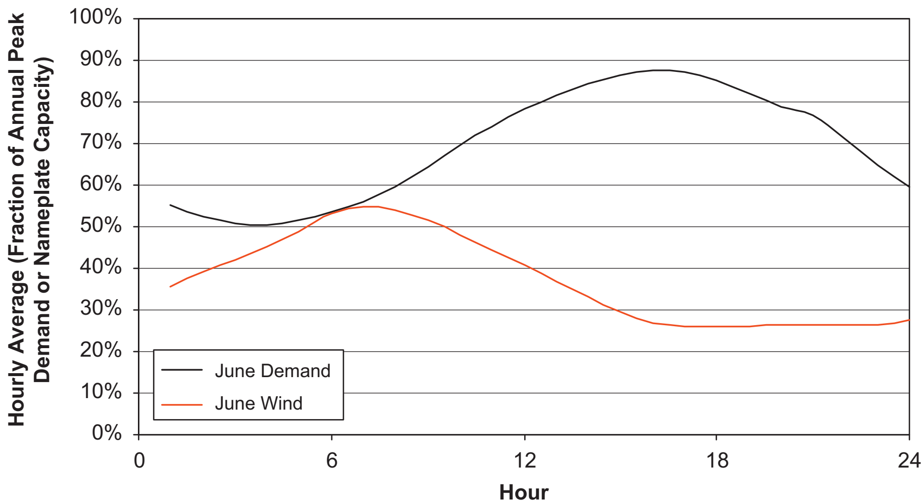

Fig. 8. Average daily wind output and electricity demand during June.

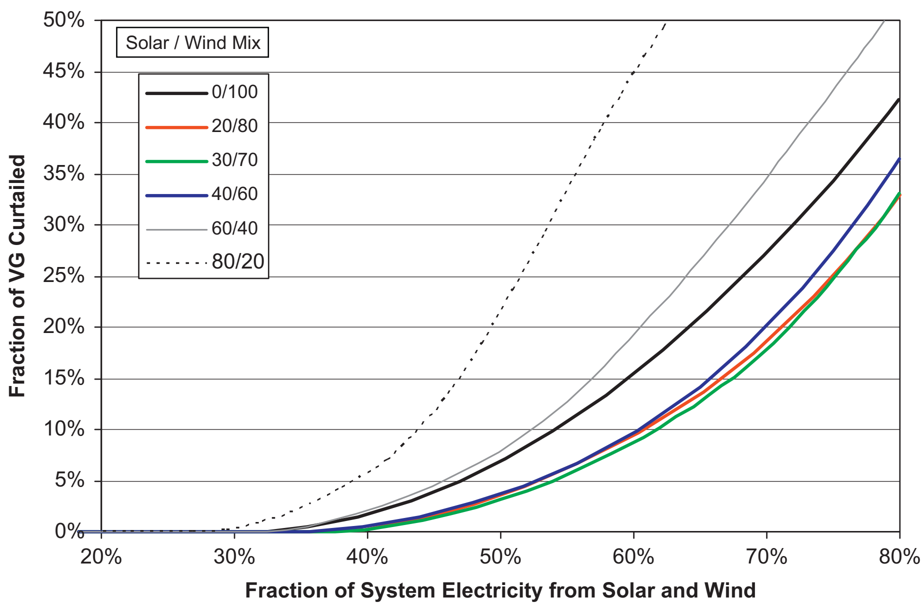

Fig. 9. Total curtailment as a function of VG energy penetration for different solar/wind mixes (assuming a 100% flexible system).

result, the point on the curve labeled "40/60" where VG is providing 50% means solar is providing 20% of the total demand (40% of 50%) and wind is providing 30% of demand (60% of 50%). As with wind, the regional mix of solar remains the same (as more solar is introduced, the distribution of solar locations remain the same, but there is just more of it at each location). For reference, the curve labeled "0/100" (meaning only wind and no solar) is the same as the 100% flexibility curve in Fig. 4. As solar is added curtailment rates drop, since the wind/solar mix is better correlated with normal demand, and less generation from this new mix occurs during periods of low demand. The minimum level of curtailment occurs in the 30% solar case (in which solar is supplying 30% of the RE generation with wind supplying the other 70%). Beyond 30%, the curtailment rate then increases rapidly, since solar exhibits far less spatial diversity than wind (particularly over hourly time scales and within the geographical constraints of this analysis), with output concentrated in less than half of the hours. This issue is discussed in length in Denholm and Margolis, 2007a,b). As noted before, this mix is designed to minimize curtailment, as opposed to minimize system costs, since it is difficult to predict potential cost reductions in PV and CSP over the time scales needed to achieve this level of penetration. While the total curtailment rate has dropped, at 80% penetration the marginal curtailment rate remains very high, exceeding 80%, meaning the last unit of VG put into the system will cost more than five times the base cost.

Even with the "optimum" mix of wind and solar and the completely flexible system assumed in Fig. 9, there are still fundamental limits to the correlation of supply and demand, primarily due to the limited production of wind and PV in the late afternoon and early evening when demand peaks. Further reduction in VG curtailment at high VG requires an additional source of flexibility is required, namely the ability to increase the coincidence of VG supply with demand.

5. High VG scenarios with energy storage and load shifting

The previous section shows that high levels of generation flexibility are necessary to achieve extremely high levels of VG,

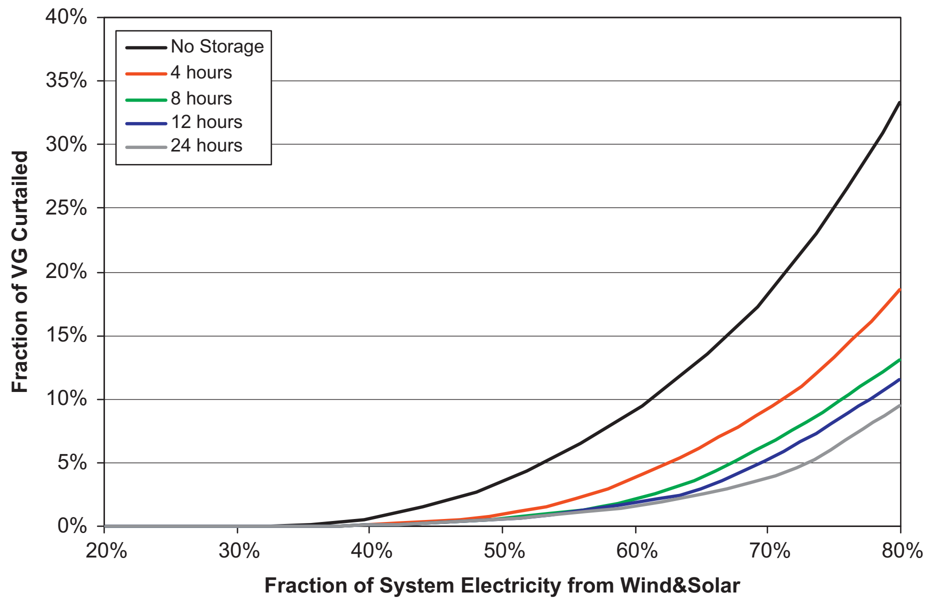

Fig. 10. Total curtailment as a function of VG energy penetration for different amounts of energy storage. (Assumes 30/70 solar/wind mix and a 100% flexible system. Each hour of storage represents one of average system demand.)

but not sufficient due to limited supply/demand coincidence and resulting curtailment.[7]

While there are a number of approaches to increasing supply/demand coincidence, our focus was estimating the amount of energy that must be shifted to increase use of VG and decrease curtailment. Because it will be some time until very high penetrations of VG are achieved, and there are many storage and load shifting technologies available or under development, we did not prescribe the specific type of load shifting or storage technology used. As a result, we assumed load can be shifted with devices with round-trip efficiencies of 60%, 80% and 100%. The 60% and 80% efficiencies represent the range of many commercially available storage technologies such as batteries and pumped hydro storage (EPRI, 2003). The 100% efficient case represents end-use load shifting, or approximates the extremely high round-trip efficiencies of thermal storage in buildings or in CSP plants. There are important caveats about the use of both load shifting and thermal storage. Thermal storage is coupled to a single application, whether on the supply side in CSP plants, or on the demand side, such as with cold storage. There are also obviously limits to how much load can be shifted. However, it is very important to consider thermal storage approaches due to both their higher round-trip efficiencies and potentially lower capital cost. More comprehensive analysis as to the technical and economic potential of load shifting must be performed, as well as detailed simulations of the load shifting possibilities of thermal storage. However, this analysis provides some insight into the amount of load shifting and storage required.

Fig. 10 shows the impact of adding energy storage with an 80% round-trip efficiency. The mix of solar and wind is 30%/70% and the system flexibility is 100%. The no storage curve then is identical to the 30/70 curve in Fig. 9, or the mix with the lowest curtailment rate. In this figure the amount of storage in the system is characterized by hours of average system demand. In this case, the average hourly demand is 34.4 GW, so 1 h of storage represents 34.4 GWh. Storage devices are characterized by both the energy capacity and power capacity, with the relationship given by the energy to power ratio, or the number of hours of storage capacity at full discharge. For example a pumped hydro plant may be rated at 1000 MW, with 12 h of storage capacity, corresponding to an energy capacity of 12 GWh. We assumed that the typical device used for bulk storage would have an energy to power ratio of 12, so each hour of system capacity (34.4 GWh) actually corresponds to a 2.9 GW device with 12 h of storage capacity.

Fig. 10 shows that the use of storage dramatically reduces the curtailment needed to achieve very high penetrations of VG. Note that curtailment includes losses in the storage device (a unit of energy placed into storage will have a curtailment rate of 20% due to the 80% round-trip efficiency).

Fig. 10 shows that a relatively small amount of storage can be used to shift the daily lack of coincidence, as illustrated previously. However there are substantial diminishing returns for greater amount of storage. The first 4 h of storage decreases curtailment by 43% from about 33% to about 19% at 80% penetration, while moving from 8 to 12 h of storage only decreases curtailment from about 13% to 12%. This amount of storage (12 h of average demand) corresponds to about 34 GW of power capacity and 414 GWh of energy capacity, and exceeds the total capacity of electricity storage currently installed in the US of about 21 GW, nearly all of which is pumped hydro (Denholm et al., 2010). There is currently no large-scale storage (electricity or CSP/thermal) deployed in ERCOT, although there are proposals for new pumped hydro and compressed air projects in Texas (FERC, 2010; Succar and Williams, 2008). Reducing the curtailment rate to less than 10% would require storage capacity of nearly 1 day of average demand, and the marginal curtailment rate with this amount of storage still exceeds 40%. Given the high costs of many current storage technologies, this emphasizes the need to explore all options for increasing flexibility including increasing system interconnections, demand response, load shifting, electrified transportation, thermal storage, and advanced, lower-cost electricity storage technologies.

[7] An additional challenge is the significant ramping requirements of the system in a high VG scenario. For example in the base scenario (no VG) the maximum ramp rate requirement of the conventional generation fleet is 4.8 GW/h. In the case where wind and solar provide 50% of the system's energy, the net load ramp rate (load minus contribution from wind and solar) exceeds 10 GW/h during 49 occasions during the year. This provides another motivation for sharing wind and load resources over large areas, which act to reduce the ramp rates of the net load (NERC, 2010)).

The limitations of larger amounts of storage are due to two factors. First, reduction in curtailment is fundamentally limited by losses in the storage process. Fig. 11 shows the effect on total curtailment as a function of the three storage efficiencies. The no storage case is the same as the no storage case in Fig. 10, with the three storage cases assuming 12 h of storage (34 GW/414 GWh). Moving from an 80% to a 100% efficient device decreases curtailment at 80% penetration from 11% to 10% with 12 h of storage/load shifting. This high efficiency represents the potential use of thermal storage, or load shifting and demand response, which could be cost-effective alternatives (or complements) to electricity storage technologies.

The second and more important factor decreasing the benefit of increasing amounts of storage is limited seasonal correlation of the combined VG mix and demand. Neither wind nor solar are perfectly correlated with load on an hourly or daily basis, but this can be addressed with short-term (a few hours) storage or load shifting. However, seasonal mis-matches are more difficult to address. Fig. 12 shows the average monthly output (normalized to peak output) for the load, wind and solar in ERCOT. Wind has the greatest non-correlation with load – it peaks in March and April, and again in November – three of the lowest demand months. Fig. 12 shows that even if all of the short-term coincidence issues are addressed, it is difficult to meet a very large fraction of the demand without the ability to move energy over longer time scales. Solar is better correlated but also tends to produce large amounts of energy in the spring during times of relatively low demand. It should be noted that as the amount of storage increases the "optimal" mix of wind and solar (based solely on curtailment rate) changes—at 12 h of storage the optimal mix moves from 30%/70% solar/wind closer to

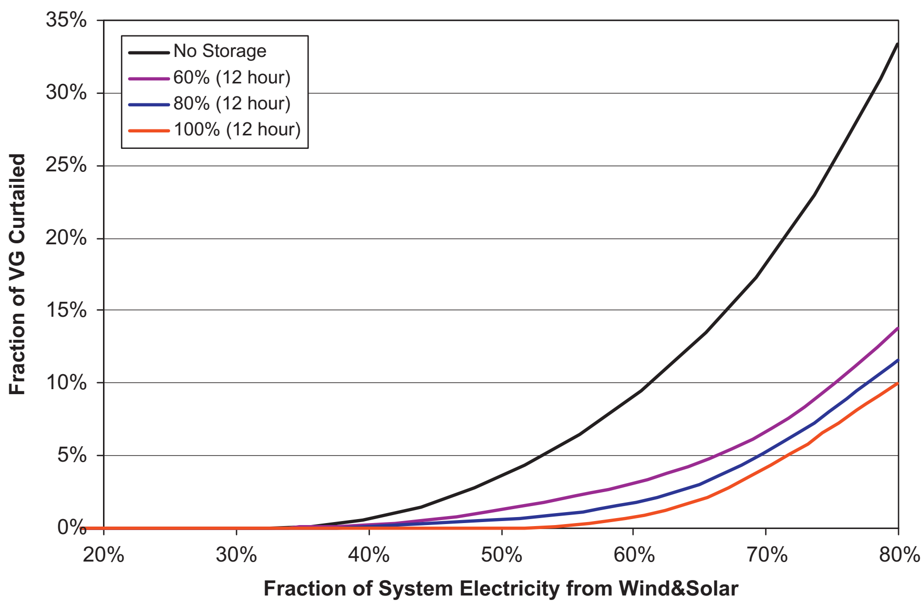

Fig. 11. Total curtailment as a function of VG energy penetration for different amounts of storage efficiencies. (Assumes 30/70 solar/wind mix, 12 hours of storage and a 100% flexible system.)

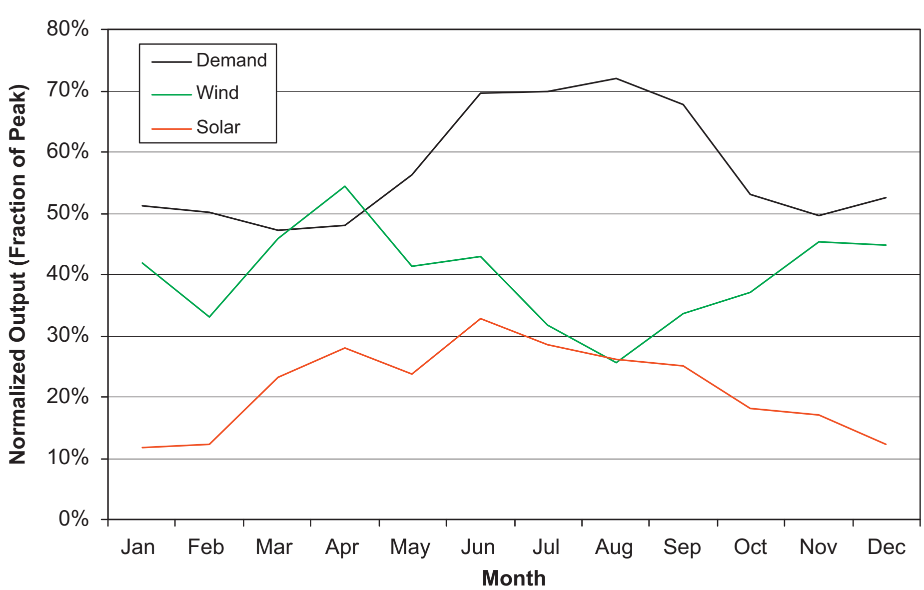

Fig. 12. Average monthly wind and solar output and electricity demand.

50%/50%. However, the total curtailment rate drops only by a few percentage points. Regardless of the mix of solar and wind, the supply of VG saturates the demand for electricity in the spring.

This seasonal mismatch would need to be addressed by either extremely long-term storage, such as air compression in very large reservoirs (Cavallo and Keck, 1995) or through new electrification applications that are flexible over various time scales, perhaps including fuel production. However, as with conventional storage, these approaches need to be placed in the context of the assumptions of this analysis. It may be much cheaper to connect the ERCOT grid to its neighbors to take advantage of a more diverse set of both VG and dispatchable renewables.

6. Conclusions

Our evaluation of ERCOT evaluates a limiting case including an isolated grid depending largely on variable renewables. This ignores dispatchable renewables such as hydro, geothermal, and biomass which would reduce the dependence on VG to achieve high levels of renewable electricity generation. This also ignores the opportunities for transmission interconnection between ERCOT and the remaining US to share resources and load, a key source of low-cost system flexibility.

Given these caveats, in an isolated system such as ERCOT achieving 80% electricity from VG is greatly dependent on increased generation flexibility, virtually eliminating minimum generation constraints imposed both by "must-run" baseload generators, and other thermal units kept on line to provide operating reserves. This also means replacing conventional spinning reserves and regulation reserves with a combination of demand response, use of curtailed VG, and other enabling technologies such as energy storage. At 80% generation from variable renewables, the remaining 20% of generation would need to be able to start and ramp extremely rapidly to respond to the highly variable and uncertain residual load.

Even with a completely flexible system, achieving 80% from VG sources in the evaluated system requires enabling technologies to address the fundamental mismatch of supply and demand. Avoiding excessive curtailment will likely require a variety of enabling technologies including load shifting, thermal storage, or electricity storage. A system capable of storing or moving 4 h of average system load can reduce curtailment to below 20% with the analyzed mix of wind and solar at 80% penetration. However the seasonal mismatch of VG resources and demand makes reduced curtailment more difficult to address using "conventional" storage technologies without very long duration (well over 24 h) storage capacities.

While the lack of power exchanges between ERCOT and the other interconnects limits definitive conclusions, this analysis reinforces and extends conclusions of previous wind and solar integration studies both in the US and worldwide. These include the critical role of deploying flexible generation on multiple time scales. A variable generation-based grid of the future must include generation that can start, stop, and ramp rapidly. It must also be able to quickly deploy reserves that may be better served by responsive load. Methods of shifting demand will become increasingly valuable, whether by markets and price responsiveness, or via new end use technologies such as thermal storage in buildings. Finally, this analysis suggests that energy storage of all types including both electricity storage and thermal storage can provide a critical role in VG integration particularly at penetrations beyond 50%. Ultimately, additional analysis will be needed to understand the grid-level changes required for the many combinations of VG, dispatchable renewables, and non-renewable sources of low-carbon electricity that may be deployed both in the US and worldwide.

Appendix A. Wind and solar resource data

For a map of the wind resource areas, along with capacity and average capacity factor in each area, see Figs. A1–A3 and Tables A1 and A2.

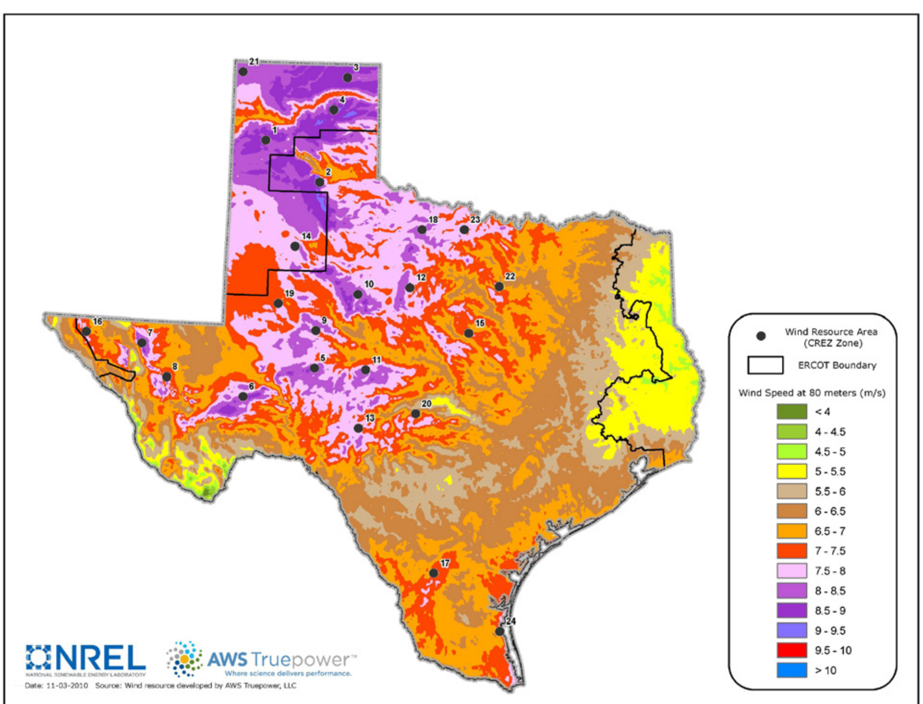

Fig. A1. Map of ERCOT territory and wind resource sites used in the analysis.

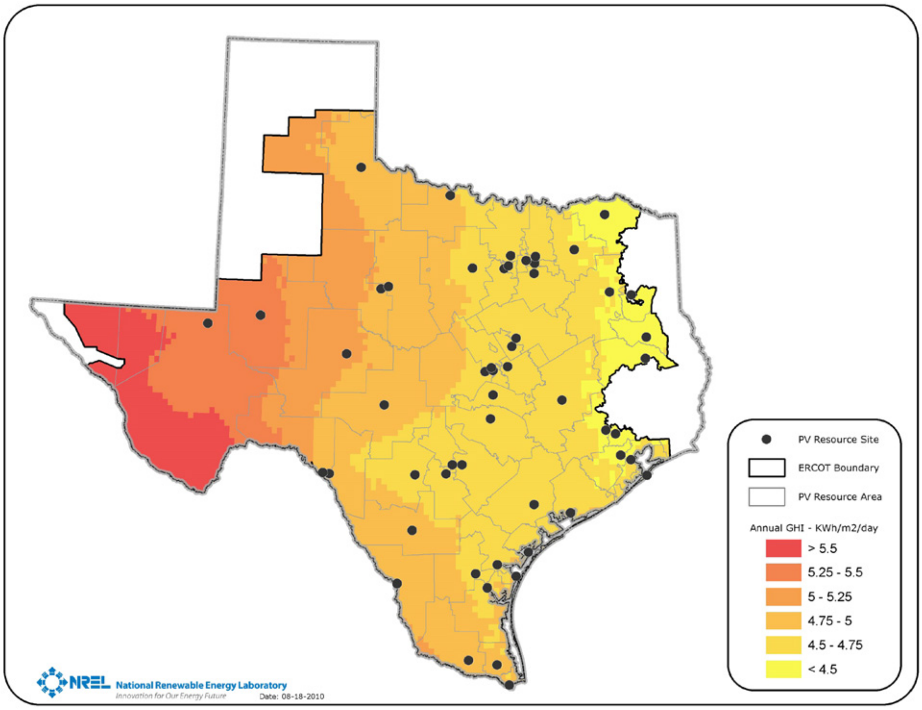

Fig. A2. Map of ERCOT territory and solar PV resource sites used in the analysis. Areas were assigned to each resource site based on proximity of census block groups.

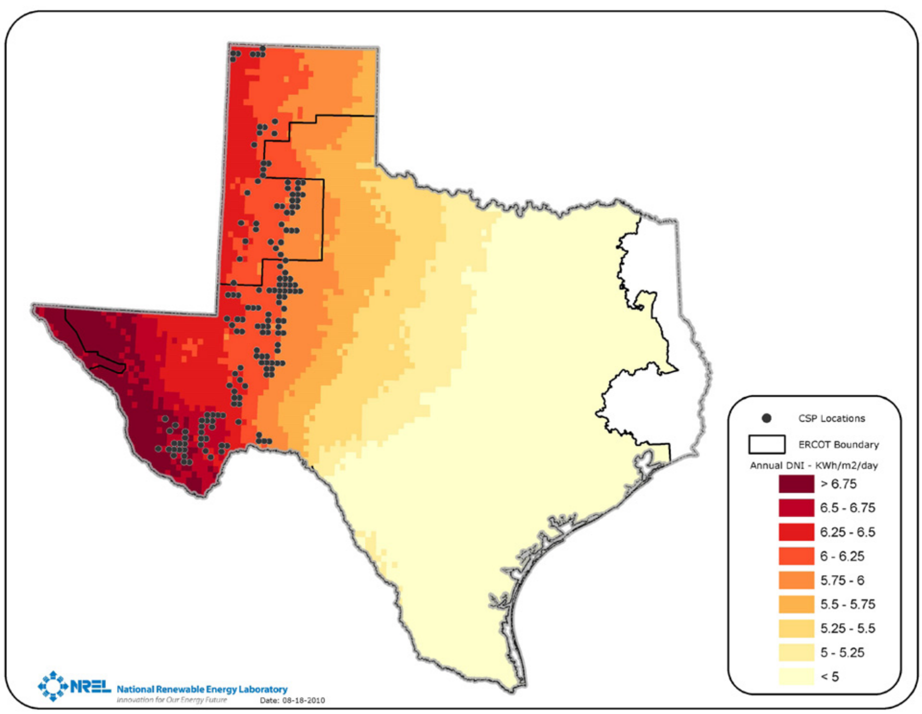

Fig. A3. Map of ERCOT territory and CSP resource sites used in the analysis.

Table A1
Wind resource areas and characteristics (see GE 2008 for additional information).

Crez zone	Total modeled capacity	Average capacity factor
1	3927	40.5
2	3971.4	41.3
3	3997.6	43.5
4	3947.4	41.8
5	3966.2	39.5
6	3962.9	40.5
7	1728.5	36.6
8	1741.6	35.7
9	3928.3	37.7
10	3970.1	38.2
11	3978.3	34.0
12	3865.3	32.9
13	2861	30.6
14	3974.5	36.0
15	2712.9	31.1
16	303.4	31.2
17	3965.1	32.0
18	3895.5	31.5
19	3749	30.1
20	2196.7	30.3
21	1279.4	38.3
22	401.7	30.0
23	3540.1	30.2
24	2254.1	34.7
25	2707.6	33.8

Table A2
Solar PV sites and capacity factor. Note capacity factor calculation uses the Solar Advisor Model (SAM) which includes a temperature-based parameterization of PV efficiency and estimates of DC–AC conversion losses.

USAF	Name	Annual production (kWh/kW)		Capacity factor	
		Fixed 25°S	1-Axis tracking	Fixed 25°S (%)	1-Axis tracking (%)
690190	ABILENE DYESS AFB	1572	2032	17.9	23.2
722410	PORT ARTHUR JEFFERSON COUNTY	1437	1824	16.4	20.8
722420	GALVESTON/SCHOLES	1489	1874	17.0	21.4
722429	HOUSTON/D.W. HOOKS	1427	1810	16.3	20.7
722430	HOUSTON BUSH INTERCONTINENTAL	1419	1797	16.2	20.5
722435	HOUSTON WILLIAM P HOBBY AP	1433	1817	16.4	20.7
722436	HOUSTON ELLINGTON AFB [CLEAR LAKE – UT]	1470	1887	16.8	21.5
722445	COLLEGE STATION EASTERWOOD FL	1439	1820	16.4	20.8
722446	LUFKIN ANGELINA CO	1415	1805	16.2	20.6
722448	TYLER/POUNDS FLD	1448	1849	16.5	21.1
722470	LONGVIEW GREGG COUNTY AP [OVERTON – UT]	1471	1914	16.8	21.8
722499	NACOGDOCHES (AWOS)	1421	1807	16.2	20.6
722500	BROWNSVILLE S PADRE ISL INTL	1397	1761	15.9	20.1
722505	HARLINGEN RIO GRANDE VALLEY I	1411	1788	16.1	20.4
722506	MCALLEN MILLER INTL AP [EDINBURG – UT]	1454	1863	16.6	21.3
722510	CORPUS CHRISTI INTL ARPT [UT]	1453	1869	16.6	21.3
722515	CORPUS CHRISTI NAS	1470	1853	16.8	21.2
722516	KINGSVILLE	1423	1808	16.2	20.6
722517	ALICE INTL AP	1413	1793	16.1	20.5
722520	LAREDO INTL AP [UT]	1450	1861	16.5	21.2
722524	ROCKPORT/ARANSAS CO	1484	1879	16.9	21.5
722526	COTULLA FAA AP	1404	1788	16.0	20.4
722530	SAN ANTONIO INTL AP	1416	1790	16.2	20.4
722533	HONDO MUNICIPAL AP	1435	1821	16.4	20.8
722535	SAN ANTONIO KELLY FIELD AFB	1419	1792	16.2	20.5
722536	RANDOLPH AFB	1424	1801	16.3	20.6
722540	AUSTIN MUELLER MUNICIPAL AP [UT]	1448	1850	16.5	21.1
722547	GEORGETOWN (AWOS)	1437	1831	16.4	20.9
722550	VICTORIA REGIONAL AP	1431	1814	16.3	20.7
722555	PALACIOS MUNICIPAL AP	1472	1859	16.8	21.2
722560	WACO REGIONAL AP	1483	1892	16.9	21.6
722563	MC GREGOR (AWOS)	1487	1893	17.0	21.6
722570	FORT HOOD	1474	1878	16.8	21.4
722575	KILLEEN MUNI (AWOS)	1482	1888	16.9	21.6
722576	ROBERT GRAY AAF	1472	1870	16.8	21.3
722577	DRAUGHON MILLER CEN	1450	1835	16.6	20.9
722583	DALLAS LOVE FIELD	1475	1880	16.8	21.5
722587	COX FLD	1494	1910	17.1	21.8
722588	GREENVILLE/MAJORS	1464	1869	16.7	21.3

Table A2 (*continued*)

USAF	Name	Annual production (kWh/kW)		Capacity factor	
		Fixed 25°S	1-Axis tracking	Fixed 25°S (%)	1-Axis tracking (%)
722590	DALLAS-FORT WORTH INTL AP	1491	1901	17.0	21.7
722594	FORT WORTH ALLIANCE	1510	1940	17.2	22.2
722595	FORT WORTH NAS	1502	1926	17.1	22.0
722596	FORT WORTH MEACHAM	1509	1940	17.2	22.1
722597	MINERAL WELLS MUNICIPAL AP	1519	1940	17.3	22.2
722598	DALLAS/ADDISON ARPT	1489	1900	17.0	21.7
722599	DALLAS/REDBIRD ARPT	1486	1899	17.0	21.7
722610	DEL RIO [UT]	1450	1834	16.5	20.9
722615	DEL RIO LAUGHLIN AFB	1444	1844	16.5	21.1
722630	SAN ANGELO MATHIS FIELD	1581	2028	18.0	23.2
722636	DALHART MUNICIPAL AP	1689	2204	19.3	25.2
722650	MIDLAND INTERNATIONAL AP	1658	2151	18.9	24.6
722656	WINK WINKLER COUNTY AP	1681	2183	19.2	24.9
722660	ABILENE REGIONAL AP [UT]	1594	2081	18.2	23.8
722670	LUBBOCK INTERNATIONAL AP	1669	2165	19.1	24.7
722700	EL PASO INTERNATIONAL AP [UT]	1781	2296	20.3	26.2
723510	WICHITA FALLS MUNICIPAL ARPT	1539	1977	17.6	22.6
723604	CHILDRESS MUNICIPAL AP	1602	2067	18.3	23.6
723630	AMARILLO INTERNATIONAL AP [CANYON – UT]	1667	2165	19.0	24.7
747400	JUNCTION KIMBLE COUNTY AP	1508	1933	17.2	22.1

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