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Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels

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Environmental Energy Technologies Division

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Executive Summary

Overview

Previously, Mills and Wiser [2012] found a decline in the marginal economic value of different variable generation (VG) technologies with increasing penetration levels. Economic value in this case is primarily based on the avoided costs form other non-renewable power plants in the power system including capital investment cost, variable fuel, and variable operations and maintenance (O&M). That previous analysis, the "valuation report," assumed only one VG technology was added at a time, that VG plants would be built at specific sites, that the commitment decisions for all thermal power plants except combustion turbines were fixed in the day-ahead market, that demand was largely inflexible, and that new bulk power storage facilities would be expensive to build. In this report, the "mitigation report," we use the same model and data to evaluate individual options that have the potential to stem the decline in the marginal value of VG with increasing penetration levels.

We measure the effectiveness of mitigation measures by comparing the marginal value of VG once a mitigation measure is implemented to the marginal value in the Reference scenario based on the valuation report without the mitigation measure, and at the same VG penetration level. A positive change in the value of the VG technology with the mitigation measure indicates that implementing the measure increases the value above the value found in the valuation report for the same level of penetration.

Where the mitigation measures are found to increase the value of VG, we also want to understand if the mitigation measures themselves are more or less economically attractive with increasing penetration of VG. Ideally, a mitigation measure both increases the value of VG and becomes more economically attractive at the same time. We therefore develop metrics to assess the economic attractiveness of mitigation measures and examine the change in those metrics with increasing VG penetration. We only consider the benefits of mitigation measures, not the costs of implementing the measure, so our results only reflect part of the information required to conduct a full cost/benefit analysis of mitigation measures.

The valuation report examined four VG technologies: wind, single-axis tracking photovoltaics (PV), and concentrating solar power (CSP) with and without thermal energy storage.[1] The changes in the value of PV and CSP without thermal storage were found to be largely similar and driven by the same factors. Adding thermal storage to a CSP facility was found to be an effective measure to mit-

[1] CSP without thermal storage is referred to as CSP_0 and CSP with 6 hours of thermal storage as CSP_6.

igate the decline in the value of CSP with increasing penetrations. In this report, we therefore focus only on the effectiveness of mitigation measures for wind and PV. CSP with 6 hours of thermal storage is only included in the analysis as one of the potential mitigation measures to stem the decline in the value of wind or PV with increasing penetration.

Approach

The specific mitigation measures examined in the report include increased geographic diversity of wind siting, technological diversity (through simultaneous combinations of VG technologies), more-flexible new conventional generation, lower-cost bulk power storage, and price-elastic demand subject to real-time pricing (RTP).

To estimate the change in the marginal value of wind or PV with the mitigation measure, we implement the measure in the original model used in the valuation report. For each penetration level of wind or PV, we then develop new long-run investment decisions, new generation dispatch decisions, and new wholesale power market prices that reflect the impact of the mitigation measure. The wholesale power prices from this market in long-run equilibrium are then used to estimate the marginal value of additional wind or PV generation.

Only one mitigation measure is implemented at a time in this report. The change in the value of wind or PV if multiple mitigation measures were implemented simultaneously is not expected to be the same as the sum of the change in value with each mitigation measure implemented in isolation.

The economic attractiveness of the various mitigation measures with increasing wind and PV penetration uses the wholesale power prices from the Reference scenario.[2] The specific metric used for each mitigation measure is described in more detail in the body of the report.

Additional relevant details of the different mitigation measures are as follows. The geographic diversity mitigation measure is based on siting wind plants in locations that minimize the variance of the aggregate wind production. This leads to wind sites being much more geographically distant from one another relative to the wind sites in the Reference scenario.[3] The technological diversity scenarios involve adding 10% penetration[4] of a different VG technology. In the case of PV, the value of PV with increasing penetration and 10% wind penetration is compared to the value of PV without any wind.[5] We also examine the value of wind with 10% PV or 10% CSP with 6 hours of thermal storage. The more-flexible new conventional generation

[2] The Reference scenario refers to the same respective penetration level in the valuation report, but without the mitigation measure applied.

[3] Geographic diversity of PV is not considered since variability from clouds has little to do with the decline in the value of PV with increasing penetration.

[4] All penetration levels are reported on an energy basis.

[5] We do not consider CSP_6 to be a mitigation measure for PV since adding CSP_6 if found to decrease the value of PV.

mitigation measure uses the assumption that new combined cycle gas turbines (CCGTs) can be started or stopped in real time as opposed to making all commitment decisions in the day-ahead market as was assumed in the Reference scenario. The low-cost bulk storage mitigation measure assumes that pumped-hydro storage with 10 hours of storage capacity can be built with a much lower investment cost than was assumed in the Reference scenario. Finally, the RTP mitigation measure assumes that load has a constant own-price elasticity of -0.1 and can change in the day-ahead and real-time market in response to changes in wholesale power prices.

Change in the Value of Wind with Mitigation Measures

The change in the marginal value of wind after implementing different mitigation measures is shown at different penetration levels in Table ES.1. The largest increase in the marginal value of wind at high penetration levels occurs with increased geographic diversity of wind sites (27% increase in the marginal value of wind relative to the value in the unmitigated scenario with 40% wind penetration), implementation of RTP (20% increase in the value of wind at 40% penetration), and availability of low-cost bulk power storage (11% increase in the value of wind at 40% penetration).

With 20% and 30% wind, the largest increase in the marginal value of wind is found with RTP. The increase in value is primarily due to an increase in the sum of the capacity and energy value of wind with increased penetration. The marginal value of wind increases because RTP tends to increase the load during times when wind power is available. Less than $2/MWh of the increase in the marginal value of wind with RTP is due to a decrease in the cost of day-ahead forecast errors.

Mitigation measure	Wind penetration		
($/MWh)	20%	30%	40%
Geographic diversity	2.5	4.9	10.6
RTP	3.7	5.0	7.9
Low-cost storage	-0.1	0.4	4.4
Quick-start CCGT	0.3	0.3	-0.6
10% PV	1.1	-1.1	-5.2
10% CSP_6	-0.2	-0.6	-4.4

Table ES.1: Change in the value of wind with mitigation measures relative to the value in the Reference scenario.

The trends currently leading to the roll-out of smart meters and RTP programs are largely based on efforts to reduce peak demand, independent of mitigating changes in the economic value of wind.

This analysis shows, however, that not only does wind increase in value with RTP, but also the attractiveness of RTP increases with increasing wind. A large portion of the increased attractiveness of RTP (as treated here) with increasing wind is derived from real-time response to events that were unforeseen in the day-ahead. Such active participation from the demand side through dynamic pricing programs as modeled here is a departure from the design of traditional demand-response programs and even some RTP programs as they are currently implemented.

With 40% wind, the largest increase in the value of wind is with increased geographic diversity. Whereas the selection of wind sites in the Reference scenario is based on a number of factors, in the high-geographic-diversity scenario the selection of wind sites is based entirely on minimizing the total variability of the aggregate wind production. Picking these sites increases the marginal value of wind at 40% penetration by \$10.6/MWh.

The increase in the marginal value of wind at 40% penetration with increased geographic diversity is based on an increase in the energy value of wind, a smaller increase in the capacity value, and a small reduction in the cost of day-ahead forecast errors. Wind from diverse sites is less correlated with wind from more concentrated sites. Increasing geographic diversity, therefore, reduces the frequency of extremes: diverse wind tends to generate at different times rather than all sites generating at the same time or no wind generating at a given time.

Though not shown in Table ES.1, we also examined a case with very low geographic diversity in wind siting. When tightly clustered wind is generating strongly from all sites at once, conventional generation with lower and lower variable costs begins to be displaced. This lowers wholesale prices during times with significant wind. Wind from geographically diverse sites can earn higher revenue compared to tightly clustered wind. Concentrating wind in one region decreases the marginal value of wind by \$6/MWh. The decrease in value compared to the original siting is driven primarily by an increase in the cost of day-ahead forecast errors.

The increased attractiveness of wind at diverse sites must be compared to factors that may increase the costs of wind sited in this fashion, including the potential for higher transmission costs and lower-quality wind resources. Since the cost of wind can vary greatly depending on the local wind resource quality, geographic diversity is not likely to dominate siting decisions.

Finally, while the technological diversity scenarios—10% PV and 10% CSP_6—do not greatly increase the marginal value of wind at 20% penetration or higher, the results are important in that adding these solar technologies does not substantially decrease the value of wind at 20% and 30% penetration. These results suggest that, if a full comparison of costs and benefits could justify 10% PV penetration alone or 20% wind alone, then 30% penetration from a combination of wind and PV could be similarly justified. The remaining results regarding the impact of low-cost storage and more flexible CCGT's are discussed in the main report. The negligible effect of more flexible new CCGT's is due in part to the flexibility already available from existing resources. Flexibility of new CCGTs would play a larger role in areas that lack as much flexibility from existing resources.

Change in the Value of PV with Mitigation Measures

The change in the marginal value of PV after implementing several different mitigation measures is not the same as for wind, Table ES.2. By far, the largest increase in the marginal value of PV at high penetration levels occurs with the availability of low-cost bulk power storage. With 30% PV penetration, the availability of low-cost storage increases the value of PV by nearly $20/MWh (an 80% increase in the marginal value of PV relative to the value in the unmitigated scenario with 30% PV penetration), due primarily to an increase in the energy value of PV. With high PV penetration, storage is charging during times with PV generation, which increases prices during these times relative to their level absent any new storage.

Mitigation measure	PV penetration		
($/MWh)	10%	20%	30%
Low-cost storage	3.3	8.4	19.7
RTP	10.4	7.5	7.4
Quick-start CCGT	-1.8	-1.0	-0.2
10% wind	7.4	-1.1	-6.4

Table ES.2: Change in the value of PV with mitigation measures relative to the value in the Reference scenario.

Likewise, the marginal value of bulk power storage increases with high PV penetration. With 30% penetration of PV, the marginal value of new storage increases by over $100/kW-yr relative to the value of storage with no PV. Decreases in the cost of multiple-hour bulk power storage could make storage the most attractive mitigation measure for moderating the decline in the value of PV at very high penetration levels.

For more modest penetration levels of PV, the two most effective mitigation measures are RTP and technological diversity with 10% wind penetration. At 10% PV penetration, these two measures increase the value of PV by more than double the increase in the value of PV from low-cost storage.

The increase in the marginal value of PV with 10% wind penetration is due to an increase in the capacity value of PV relative to the Reference scenario. The value of wind also increases with 10% PV penetration, suggesting that if wind were attractive without PV it would be just as attractive, if not more, with 10% PV. With higher PV penetration, however, 10% wind begins to decrease the value of PV relative to the Reference scenario. Wind is therefore an attractive mitigation measure for relatively modest PV penetration levels. CSP_6 decreases the value of PV, so it is not considered in detail as a mitigation measure.

The increase in the marginal value of PV with RTP is due to an increase in demand when PV is generating. As mentioned earlier for wind, the development of RTP programs is currently largely independent of issues involving renewable energy, but the attractiveness of RTP does increase with both increasing PV and wind penetration. The remaining results regarding the impact of more flexible CCGT's are discussed in the main report.

Conclusions

In summary, several mitigation measures both increase in attractiveness with increasing penetration of wind and PV and increase the marginal value of wind and PV relative to a scenario without the mitigation measure. This report is also helpful in highlighting measures that may not increase the value of wind or PV or, in some cases, can even decrease the value. The largest increase in the value of wind comes from increased geographic diversity. The largest increase in the value of PV comes from assuming that low-cost bulk power storage is an investment option. Other attractive options include RTP and technology diversity. These mitigation measures may have costs or may be driven by factors not directly related to increases in wind and PV. Decisions to implement specific mitigation measures should account for these costs and consider other important factors not included in this analysis.

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Acronyms

AS	Ancillary services
CCGT	Combined cycle gas turbine
CSP	Concentrating solar power
CT	Combustion turbine
DA	Day ahead
ERCOT	Electric Reliability Council of Texas
EIA	Energy Information Administration
O&M	Operations and maintenance
PHS	Pumped hydro storage
PV	Photovoltaic
RT	Real time
RTP	Real-time pricing
WREZ	Western Renewable Energy Zone Initiative
WWSIS	Western Wind and Solar Integration Study
VG	Variable generation

1 Introduction

The addition of significant quantities of variable generation (VG) to a power market will face technical, economic, and institutional challenges. A large body of research and actual operating experience with large shares of VG indicate that integrating VG[6] into the grid is technically feasible [e.g., IPCC, 2011]. As far as economic challenges, costs of renewables are still declining, and a growing body of literature examines the economic value of VG and how it changes with increasing penetration [e.g., Hirth, 2013]. Increasingly these economic studies attempt to incorporate the economic implications of technical challenges associated with VG. For instance, the share of studies that account for the detailed operational constraints of conventional generation when estimating the economic value of VG is growing.

[6] Variable generation is sometimes called variable energy resources (VER) in other literature.

In a previous report, we explored how the long-run marginal economic value of VG changed with increasing penetration levels [Mills and Wiser, 2012]. The analysis used a long-run economic framework that accounted for changes in the mix of generation resources due to new generation investments and plant retirements while also incorporating significant detail important to power system operations and dispatch with VG. Economic value of VG was primarily based on the avoided costs form other non-renewable power plants in the power system including capital investment cost, variable fuel, and variable operations and maintenance (O&M). In that report, the "valuation report," we examined how the marginal economic value of individual VG technologies changed as penetrations increased. This was carried out for wind, single-axis-tracking photovoltaics (PV), and concentrating solar power (CSP) with and without 6 hours of thermal energy storage (CSP_6 and CSP_0, respectively). Only one VG technology was deployed at a time. The analysis in the valuation report further assumed demand was very inelastic, that new conventional generation plants had similar operating constraints as incumbent generation resources, VG siting was not optimized for geographic diversity, and that the cost of new bulk power storage was relatively high.[7]

[7] The cost of storage in the Reference scenario, $700/kW-yr, was based on the cost of new pumped-hydro storage from EIA [2011].

The valuation report highlighted a number of important conclusions. The marginal value of wind was found to be largely based on the energy value (with lower capacity value) and therefore slightly lower than the value of a flat block of power at low penetration. The marginal value of wind was found to decline with increasing penetration, particularly at penetration levels above 30%.[8] The marginal value of wind decreased by 40% when going from 0% wind to 40% wind penetration. The marginal value of solar, on the other hand, was found to be relatively high at low penetration levels, particularly

[8] Throughout this document, all penetration levels refer to the share of annual energy demand that is met by renewables (i.e., penetration on an energy basis).

due to the high capacity value. As the penetration increased, the values of PV and CSP without thermal storage declined due to an initial steep drop in the capacity value followed by a decline in the energy value. The marginal value of PV decreased by 72% when going from 0% to 30% PV penetration. The value of CSP with thermal storage dropped much less with increasing penetration and had a distinctly higher marginal value at high penetration relative to the other solar technologies and wind. The marginal values of wind, PV, and CSP with thermal storage in the Reference scenario of the valuation report are reproduced in Figure 1.[9] A number of these conclusions for wind and solar are supported by results from other studies and from empirical evidence in other regions [e.g., Hirth, 2013].

[9] The change in the value of CSP without thermal storage was similar to that of PV.

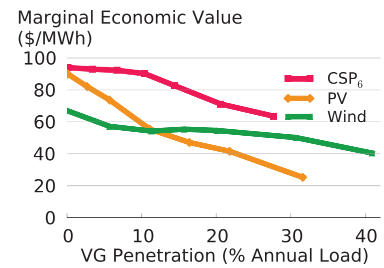

Figure 1: Marginal economic value of wind, PV, and CSP with thermal storage found in the Reference scenario of the valuation report.

The objective of our current report, the "mitigation report," is to evaluate several different mitigation measures[10] that may increase the value of VG at high penetration levels relative to the results found in the valuation report. The specific measures include increased geographic diversity, technological diversity (through simultaneous combinations of VG technologies), more-flexible new conventional generation, lower-cost bulk power storage, and price-elastic demand subject to real-time pricing (RTP). Although this is not a comprehensive list of available mitigation measures, these measures span a broad range of simplified representations of options to address challenges identified in the valuation report. Whereas the valuation report assessed wind, PV, CSP_0, and CSP_6 in detail, in this report we focus primarily on measures to mitigate changes in the value of wind and PV. CSP technologies receive less attention because the values of PV and CSP_0 were found to follow similar trends, and changes in the value of CSP_6 were already mitigated in part by the addition of thermal storage.

[10] Mitigation measures are sometimes referred to as integration options in other literature.

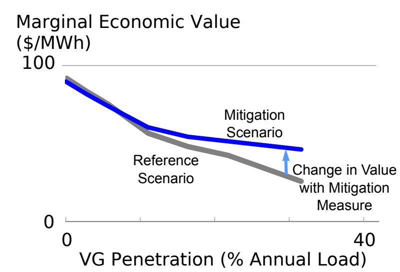

Figure 2: As shown here, change in the value of VG after implementation of a mitigation measure is defined in relation to the value in the Reference scenario from the valuation report.

The primary question in evaluating each mitigation strategy is: If this mitigation strategy were to be implemented, how would it change the value of VG relative to an unmitigated case? We determine the change in the marginal value of VG after implementing the mitigation measure relative to the marginal value of VG at the same penetration level without the mitigation measure (i.e., the value in the Reference scenario from the valuation report), as illustrated in Figure 2. To make this comparison, we use new scenarios in which a mitigation measure is implemented, find new long-run equilibrium investments and wholesale prices with that mitigation measure, and then recalculate the value of VG in that new long-run equilibrium. For example, we decrease the investment cost for new pumped-hydro storage (PHS) from the high level in the Reference scenario, in which no new storage is built, to a much lower level that causes new storage to be built in the model. We then compare the value of VG in the

Low-cost Storage scenario to the value of VG at the same penetration level in the Reference scenario. An increase in the value of VG with the mitigation measure relative to the case without the mitigation measure signals that the mitigation measure can help moderate the decline in the value of VG with increasing penetration found in the valuation report.[11]

An obvious related question is whether it makes economic sense to pursue these mitigation measures. We cannot answer that question directly in this analysis, because it requires understanding both the cost and the economic value of implementing the mitigation measures. We do not address the cost, primarily owing to a lack of comparable data; some measures are relatively new and have not yet been deployed at scale, while others require data and analysis tools that are beyond the scope of this report. In addition, many of the measures that might mitigate the decline in the value of VG are driven by factors other than renewables. RTP, for example, is usually justified on the basis of reductions in peak demand. Other measures, such as increased flexibility in conventional generation, are driven by a need for reliability, not necessarily economics. It is helpful to determine whether these measures make economic sense, but economic considerations are not necessarily the main justification for pursuing them. Likewise, any benefit of RTP or flexible generation in increasing the economic value of VG is, in many cases, an ancillary one relative to the larger value proposition from these resources.

We do, however, provide insight into a related question: Does the marginal economic value of a mitigation measure increase with larger shares of VG? While we do not determine if mitigation measures produce a net gain, because we do not consider the cost of the measures, we do use the modeling framework to determine if the marginal economic value of mitigation measures increases with increasing VG. If the value increases, then the overall economic attractiveness of the mitigation measures could be greater with increased VG than without. Conversely, if there was no strong reason to implement a mitigation measure without VG and the value of the measure does not increase with increasing VG penetration, then there would be no apparent reason to implement the measure with VG. In the best case, the marginal value of a mitigation measure would increase with increasing VG, and implementing that measure would increase the marginal value of VG relative to a case without the measure. Again, however, showing an increase in marginal value due to a mitigation measure does not on its own indicate that the measure should be implemented; a full analysis of VG and mitigation-measure values and costs would be required to evaluate their net economic impacts.

The remainder of the report is organized as follows. Section 2

[11] We do not consider uncertainties in parameters (e.g., uncertain natural gas or carbon prices) that will impact the absolute level of the value of VG. We are primarily interested in the difference in value between the case with the mitigation measure and the Reference scenario, a metric that is less sensitive to these uncertainties.

provides an overview of several studies that have examined various mitigation measures with increasing penetrations of VG. Previous studies have often not evaluated the long-run marginal value of VG or of mitigation measures while considering more detailed operational constraints on conventional generation. Our report contributes to filling this gap in the literature. Section 3 outlines the methodology used in this report to compare the marginal economic value of VG with and without mitigation measures.[12] This section also describes how we estimate the change in the marginal economic value of the mitigation measures with increasing VG penetration levels. Section 4 covers the impact of each mitigation measure on the value of VG. Additional details on the methodology specific to each mitigation measure are described in the subsection specific to the measure. Section 5 examines whether the marginal values of the mitigation measures increase with increased penetration of VG. Section 6 summarizes key findings.

[12] Details of the overall long-run economic framework and the basic assumptions used in the model remain the same as in the valuation report and thus are not repeated here.

2 *Background*

Most of the mitigation measures assessed in this report have been described elsewhere, although that literature is primarily focused on wind. Many of these previous studies identify non-economic advantages of these mitigation measures. For example, assessments of geographic diversity might demonstrate the reduced aggregate variability of wind without quantifying the increase in the economic value of geographically diverse wind. Other studies not only explore these non-economic advantages, but also quantify the increase in economic value. Grubb [1991] is an early example of a study that considers the change in the economic value of wind with geographic diversity, more-flexible conventional generation, and improved forecasting in the United Kingdom. Hirth and Ueckerdt [2013] is a very recent example that estimates the value of wind with more-flexible provision of ancillary services (AS), more-flexible combined heat and power plants, increased transmission capacity between neighboring regions, and increased storage capacity in Germany. They find that these mitigation measures can increase the value of wind relative to an unmitigated case but do not prevent a drop in the value of wind with increasing penetration. Like these papers, our report compares the benefits of several mitigation measures over a wide range of penetration levels for both wind and PV. The remainder of this section summarizes literature relevant to specific mitigation measures.

Geographic diversity is perhaps the most widely studied mitigation measure for wind. DeCarolis and Keith [2006] find total costs to be lowered by building transmission to multiple remote wind locations rather than limiting the increase in wind penetration to one site. Milligan and Factor [2000] similarly find benefits of geographic diversity in wind locations, although wind-resource quality is a more important factor. They show that the overall least-cost portfolio of wind locations exclude sites with low wind speeds, even if those low-quality sites are further away from others. Kempton et al. [2010] demonstrate clear differences in off-shore wind patterns along the U.S. Atlantic coast. They find that if these off-shore sites were to be connected by transmission, the aggregate wind generation would rarely approach zero power generation, even though zero output is common at individual wind sites. Similar results were found in the Midwestern United States by Archer and Jacobson [2007]. Obersteiner and Saguan [2011] highlight the increase in the economic value of wind with increased geographic diversity in central Europe.

Less analysis has been done on the geographic-diversity benefits of solar. Mills and Wiser [2010] and Hoff and Perez [2010] find clear benefits from geographic diversity in reducing short-term variability of PV caused by clouds but do not assess longer-timescale issues like day-ahead (DA) forecast errors. Denholm and Margolis [2007b] point to the challenges with diversifying PV production over longer hourly timescales given that production will be dictated largely by whether the sun is up, which is not substantially affected by geographic diversity.

Technological diversity in terms of the complementary profiles of wind and solar is highlighted in the California Intermittency Analysis Project by Piwko et al. [2007]. Nikolakakis and Fthenakis [2011], Denholm and Hand [2011], and Lew et al. [2013] find less curtailment for combinations of wind and solar compared to similar penetrations of one technology alone. Denholm and Hand find that the ratio of wind to PV that leads to the lowest curtailment with high aggregate renewable penetrations is 30% PV to 70% wind in the Electric Reliability Council of Texas (ERCOT) region. Vick and Moss [2013] find better matching to load for combinations of wind and solar compared to wind alone. Budischak et al. [2013] find that combinations of PV and wind have lower costs than wind alone for all-renewable systems. Lamont [2008] examines the change in the value of wind and PV with increasing penetration using data from California, including a sensitivity analysis of the cross impacts between wind and PV. Lamont finds that increasing PV penetration to 10% increases the marginal value of wind by about $6/MWh, but increasing wind penetration only slightly increases the marginal value of PV. Denholm and Mehos [2011] consider the possibility of synergies between PV and CSP with thermal storage. By assuming that CSP with thermal storage can reduce the overall system minimum generation level, they find that curtailment of PV at 25% penetration is reduced to below the curtailment level for 15% PV in a scenario without the "flexibility benefits" from CSP. Key to this result is the assumption that conventional generation with high minimum generation levels would be required if CSP with thermal storage were not available and that adding CSP with thermal storage displaces those resources with high minimum generation levels.

The advantages of more-flexible thermal generation are frequently discussed both in terms of increasing the profitability of thermal generators and in terms of integrating wind and solar. Ma et al. [2012] evaluate the profitability of flexible and inflexible plants with increasing wind based on a case study of an IEEE test system. They find the profitability of flexible plants depends in part on the magnitude of wind forecast errors. Several papers illustrate the difference in profitability of power plants that are modeled as perfectly flexible or modeled accounting for realistic operating constraints [e.g., Gardner and Zhuang, 2000, Tseng and Barz, 2002, Deng and Oren, 2003]. These results can be used to estimate the potential upper bound on how much profits can be increased by increasing the flexibility of power plants. Denholm and Margolis [2007b] estimate the reduction in PV curtailment that can be achieved with reductions in the minimum generation limits of conventional power plants. In contrast to a relatively large increase in the value of wind in the United Kingdom that was found with more-flexible generation by Grubb [1991], EnerNex Corp. [2008] finds that adding more-flexible generation led to only a slight reduction in wind-integration costs with 20% wind penetration in the Public Service of Colorado service territory.

Storage is frequently suggested as a potential measure to mitigate impacts of wind and solar, although the cost of storage is often prohibitive. Sioshansi [2011] provides a thorough review of the wind and storage literature, then examines the increase in the value of wind with storage in a system where generators exercise market power. Sioshansi et al. [2009] estimate the value of storage based on wholesale power prices in the PJM region. They find that the increase in the value of storage with increasing storage capacity slows when the storage reservoir capacity reaches about 8 hours. Denholm and Margolis [2007a] find that 8–12 hr of bulk power storage capacity can greatly reduce PV curtailment with PV penetrations exceeding 20%. Rasmussen et al. [2012] find large benefits to adding 6-hr bulk power storage in scenarios with over 50% renewables penetration but only marginal benefits for adding low-efficiency, seasonal storage. Hirth [2013] estimates the change in the value of wind and PV with assumptions of low or high amounts of PHS in Germany. Hirth finds that increases in storage increase the value of PV more than wind at high penetration levels, because the diurnal generation pattern of PV is well suited to storage with 6–8 hours of reservoir capacity, whereas periods of especially high and especially low wind generation occur over longer timescales. Garcia-Gonzalez et al. [2008] develop a method to determine optimal DA bids for wind and storage given uncertainty in wind and wholesale power prices. They find joint operation of storage and wind to be more profitable than separate, uncoordinated operation due to assumed penalties for deviations of actual generation from DA schedules. In Ireland, Tuohy and O'Malley [2011] find that the capital cost of PHS is prohibitive until wind penetrations exceed about 42%. Steffen and Weber [2013] derive a straightforward method to estimate the optimal storage capacity in a system with and without variable renewables based on a load duration curve and modified screening curve approach. This approach has the disadvantage of ignoring operational constraints on thermal power plants and potential reservoir capacity limits. On the other hand, it provides the distinct advantage of a clear, transparent, and quick method for estimating optimal storage capacities under a wide range of scenarios. Lamont [2013] develops a theoretical framework to evaluate the marginal value of storage and to characterize the impact of storage on wholesale power prices. One particularly relevant finding is that storage tends to moderately increase off-peak prices, which are not sensitive to increased demand from charging storage, and greatly reduce peak prices, which are very sensitive to increased generation from discharging storage. Lamont indicates that storage could provide a relatively small benefit to wind (which tends to generate during off-peak times) while having a negative impact on solar (which tends to generate during peak times).

Finally, RTP as a mitigation measure for wind is explored in detail by Sioshansi and Short [2009] based on a case study of the ERCOT region in Texas. They consider detailed operational constraints of thermal generation and transmission limits between wind-rich regions and load centers using a short-term framework (i.e., they do not consider retirement or investments in conventional generation). The introduction of RTP is estimated to increase the value of wind by $6–10/MWh, depending on the assumed price elasticity of demand. De Jonghe et al. [2012] consider wind and RTP in a long-run investment framework that accounts for own-price (prices in the same hour) and cross-price (prices in different hours) elasticities of demand and some thermal plant operational constraints like ramp rates. They find a slight increase in the optimal amount of installed wind with RTP compared to the optimal amount of wind without RTP. Including cross-price elasticities increases the optimal installed wind by more than it is increased when cross-price elasticities are ignored. Denholm and Margolis [2007a] estimate the reduction in PV curtailment that is possible when assuming that up to 10% of each day's normal demand can be shifted to other hours of the day to absorb PV generation. Callaway [2009] develops new methods to control a population of thermostatically controlled loads to produce grid-balancing services that will be required more often with increased wind and solar generation. An advantage of this approach is that services can be provided without large (or even noticeable) impacts to customer comfort levels. A potential disadvantage is that the timescale of the response provided may be shorter than multiple hours. Qualitative evaluation of renewable integration needs and various demand response programs by Cappers et al. [2012] suggests that balancing services over these longer timescales may be especially important for renewable integration. However, RTP programs that may provide response across longer timescales have far less regulatory and stakeholder support, particularly at the residential level, than incentive-based demand-response programs. Klobasa and Obersteiner [2006] survey the demand-response potential of different sectors in Germany then estimate the reduction in balancing costs in scenarios with high wind if that demand response were available. They identify several sources of demand response that could be activated 20–200 times per year with short notice (within the operating day) and could maintain that response for several hours. Accessing this demand-response potential would require suitable tariffs, communication infrastructure, and in some cases aggregators for small customers.

Other mitigation measures are discussed in the literature but are not considered in our report. The model used in this report, as in the valuation report, does not consider market trades with nearby regions over transmission interties (although variable renewable generators are located outside of California). Nicolosi [2012] identifies the level of policy support needed to supplement revenue renewable generators earn from the wholesale power market to cover the investment cost of wind and PV and achieve target deployment levels in Germany. Nicolosi finds that increased grid capacity between Germany and neighboring regions increases the value of wind and PV, thereby lowering the support costs. Hirth and Ueckerdt [2013] find a similar increase in the value of wind in Germany with increased grid capacity to other regions.

3 Methodology

3.1 Modeling Framework

The methods used in this report are based on the same model and framework used in the valuation report [Mills and Wiser, 2012]. In that model, the marginal economic value of VG at increasing penetration levels is calculated by adding VG to a competitive, "energy-only" power market[13] then determining hourly prices (for DA energy, real-time [RT] energy, and AS) over a year when the rest of the market reaches long-run equilibrium given the VG penetration. The long-run equilibrium accounts for changes in the mix of generation resources due to new generation investments and plant retirements for both technical reasons (i.e., when generators reach the end of an assumed technical service life) or for economic reasons (i.e., when generation is not profitable enough to cover its ongoing, fixed operations and maintenance [O&M] costs).

[13] In an "energy-only" market, no capacity obligation is placed on load-serving entities, and prices are allowed to spike to high levels to indicate periods of scarcity. In contrast, many organized wholesale markets impose a capacity obligation on load-serving entities or operate an auction for capacity payments to meet a target level of installed capacity. Energy and AS prices in markets with capacity obligations are not expected to rise to high levels to indicate periods of scarcity (unlike the "energy-only" market modeled in this report). The energy and AS prices in markets with capacity obligations do not, on their own, signal the contribution of a generating resource to meeting system needs in critical periods.

The new non-VG investment options include natural gas combined cycle gas turbine (CCGT) and combustion turbine (CT) plants as well as coal, nuclear, and PHS. The investment framework is based largely on the idea that new investments in conventional generation will occur up to the point that the short-run profits of that new generation (revenues less variable costs) are equal to the fixed investment and fixed O&M costs of the generation.

For new generation to fully cover its fixed investment and O&M costs through the power market, wholesale prices must periodically exceed the marginal fuel cost of generation. In some hours, generation will be at its full capacity and unable to meet all of the AS targets, and eventually load will need to be shed involuntarily. The wholesale prices in those hours rise to predefined, administratively set scarcity prices that reflect the need for additional generation at those times. In other hours, excess generation can lead to curtailment of generation. There are no additional penalties or costs associated with curtailment, so prices periodically fall to zero but do not become negative.

Many of the results in this paper reflect the assumption of a system in long-run equilibrium. Other studies that add VG to a static mix of conventional generation reflect the short-run assumption that generation investments do not change in response to large increases in new VG generation. Those studies are more likely to see overall decreases in wholesale prices with increasing VG compared to the behavior of long-run equilibrium prices with increasing VG penetration. In long-run equilibrium, prices need to remain high enough to cover the fixed cost of any new investments. The timing of high prices is likely to shift with increased VG prices, but the overall level is less likely to decrease.

3.2 Marginal Economic Value

The marginal value of VG is based on the revenue variable generators earn when selling power into such a power market in long-run equilibrium. The total revenue is calculated as the sum of the revenue earned by selling forecasted generation into the DA market at the DA price and the revenue earned (or lost) by selling any deviations from the DA forecast in the RT market at the RT price. No punitive imbalance penalties are levied on VG for RT generation that differs from the DA forecast. Instead, deviations from the DA forecast are generally sold at an RT price that is lower than the DA price, or shortfalls in RT generation from the DA forecast are purchased at RT prices that exceed the DA price. In addition, VG is allowed to sell AS. In the case of PV and wind, the AS that they can sell is regulation in the downward direction. Wind and solar are also charged for any assumed increase in the hourly AS requirements due to short-term variability and uncertainty. Following the assumptions in the valuation report, the regulation reserve requirement is assumed to increase by an amount equivalent to 5% of the DA forecast of wind and PV in each hour.

To better understand the source of value and the causes of changes in value, we decompose the value into four categories:

- Capacity Value ($/MWh): The portion of net revenue earned during hours with scarcity prices (defined to be greater than $500/MWh).
- Energy Value ($/MWh): The portion of net revenue earned in hours without scarcity prices, assuming the DA schedule exactly matches the RT generation.
- Day-ahead Forecast Error ($/MWh): The net earnings from RT deviations from the DA schedule.
- Ancillary Services ($/MWh): The net earnings from selling AS in the market from wind or PV and paying for increased AS due to increased short-term variability and uncertainty from wind or PV.

Similar to the valuation report, the resulting estimate of the marginal economic value is based only on a subset of the benefits related to implementing mitigation measures or adding VG. The subset of the benefits examined in this report is primarily based on avoiding the capital investment cost and variable fuel and O&M costs from other (fossil-fuel-based) power plants in the power system. These avoided costs are calculated while accounting for operational constraints on conventional generators and the increased need for AS when adding VG. As in the valuation report, the economic value reported here is the marginal economic value based on the change in benefits for a small change related to the mitigation measure (e.g., a small change in the amount of bulk power storage) or in the amount of VG at a particular penetration level. The analysis similarly does not consider many other costs and impacts that may be important, including environmental impacts, transmission and distribution costs or benefits, effects related to the “lumpiness” and irreversibility of investment decisions, and uncertainty in future fuel and investment capital costs.

For the most part, the analysis also does not consider the cost of VG nor the cost to implement mitigation measures. Instead we focus on the economic value of VG and mitigation measures; a full comparison among generation technologies and mitigation measures would need to account for both the value and the cost. One exception is the low-cost storage mitigation measure. In this case, the mitigation measure is implemented by lowering the assumed investment cost for PHS then allowing the model to find the amount of new PHS that would be built in long-run equilibrium for the given VG penetration. If the true cost of PHS were to fall to this level, which is much lower than the cost assumed by the U.S. Energy Information Administration (EIA) in its *Annual Energy Outlook 2011* [EIA, 2011], then the cost of implementing the bulk power storage mitigation measure would be fully accounted for. On the other hand, if an external policy measure (e.g., a storage subsidy or a utility requirement to invest in a certain amount of storage) were used to lower the market cost of storage, then this analysis would similarly be ignoring the cost of that subsidy or investment mandate.

NOTE THAT THE METHODS USED TO CALCULATE MARGINAL VALUES in the main sections of this report—Section 4 (Change in the Value of VG after Implementing Mitigation Measures) and Section 5 (Change in the Value of Mitigation Measures with Increasing VG)—are substantially different. Briefly, in Section 4, two separate scenarios are modeled through long-run equilibrium for each mitigation measure: the valuation report's Reference scenario without the mitigation measure and a scenario in which the mitigation measure is fully implemented; the marginal values of VG between the two scenarios are then compared at each VG penetration level. In Section 5, the scenarios analyzed are all based on the long-run equilibrium prices in the Reference scenario with no mitigation measures implemented; the marginal value of a mitigation measure in one of these scenarios thus represents the potential short-run profit of implementing the measure for the first time. More detail on the methods used in Sections 4 and 5 are included in the introductions to each section.

3.3 Case Study of California in 2030

The mitigation analysis is based on the same case study used in the valuation report. The case study loosely matches characteristics of California projected to 2030. These characteristics of California include generation profiles for VG, existing generation capacity, and the hourly load profile. Thermal generation parameters and constraints (e.g., variable O&M costs, the cost of fuel consumed just to have the plant online, the marginal variable fuel cost associated with producing energy, start-up costs, limits on how much generation can ramp from one hour to the next, and minimum generation limits of generation that is online) are largely derived from observed operational characteristics of thermal generation in the Western Electricity Coordinating Council (WECC) region, averaged over generators within the same vintage. Aside from fossil-fuel-fired generation, the existing generation modeled in California includes geothermal, hydropower, and PHS. California load and conventional generation is treated in isolation from any other load or conventional generation in the rest of WECC. In other words, we do not consider existing or future transmission capacity between California and the rest of WECC, except for imports of VG to serve California loads. Fossil-fuel prices are based on the fuel prices in 2030 in the EIA's *Annual Energy Outlook 2011* reference case forecast [EIA, 2011].

4 *Change in the Marginal Value of VG after Implementing Mitigation Measures*

The primary question of this report is: How much does the marginal economic value of VG change when a mitigation measure is implemented relative to the value without the mitigation measure? To answer this question, we estimate the marginal economic value of VG in a case with the mitigation measure and compare it to the marginal economic value of the same VG technology at the same penetration level in the Reference scenario from the valuation report. Implementing the mitigation measure requires re-running the model to determine a new long-run equilibrium with the measure implemented. For example, in the case of price-responsive demand with RTP, the marginal value of VG is estimated where the price elasticity of demand is changed from very inelastic (with a constant elasticity of -0.001) in the Reference scenario to an elasticity of -0.1 in the RTP mitigation scenario. Relative to the Reference scenario, the new long-run equilibrium with price-responsive demand and RTP results in less investment in conventional generation capacity irrespective of the VG penetration. The reduction in conventional capacity is a result of consumer willingness to reduce demand during hours with high prices (rather than needing to build new generation capacity to meet demand in those hours). The resulting long-run equilibrium prices in a scenario with RTP are used to estimate the marginal value of VG. This economic value is then compared to the economic value in the Reference scenario at the same penetration level to determine how well the mitigation strategy is able to moderate the decline in the marginal value of VG with increasing penetration.

We start by describing the change in the marginal value of VG with geographic diversity, then address technological diversity. Next we examine the impact of assuming that new CCGTs are more flexible than existing CCGTs. We then describe the impact of lowering the cost of new storage in terms of the amount of storage that is built with different VG penetration levels, the dispatch of storage, and the change in the value of VG with low cost storage. Finally, we simulate the impact of RTP by changing the elasticity of demand.

4.1 *Change In the Marginal Value of VG with Geographic Diversity*

Wind sites in the Reference scenario were selected from resource hubs identified in the Western Renewable Energy Zone (WREZ) Initiative [Pletka and Finn, 2009]. These resource hubs are assumed to have a finite capacity available for building wind plants. As the penetration of wind was increased in the Reference scenario, wind sites from additional WREZ hubs were included in the wind portfolio. As a consequence, a certain amount of geographic diversity is already reflected in the Reference scenario, Figure 3.

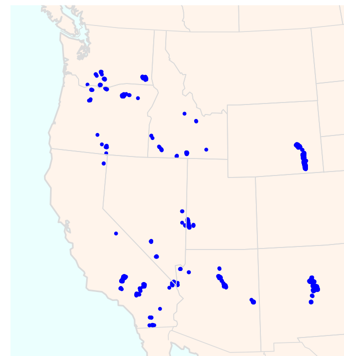

Figure 3: Location of wind sites in the Reference scenario with 40% wind penetration.

In this mitigation analysis, we develop an alternative wind portfolio in which wind sites are selected using only the criteria that the sites are geographically diverse. We use increasing wind penetration at these high-diversity sites to find new investment and dispatch decisions and long-run equilibrium power prices. We then compare the marginal value of wind in this Diverse scenario to the marginal value of wind in the Reference scenario. For illustration purposes, we similarly find the change in the marginal value of wind in a scenario that concentrates all of the wind sites in one region. In this Concentrated scenario, the wind sites are located at WREZ hubs in and around Southern California.[14]

[14] In the Concentrated scenario, we ignore constraints identified in the WREZ Initiative in terms of how much wind could be sited in a particular region. We still use individual 30-MW wind sites from the WWSIS dataset to build the wind profiles, so we do capture some geographic diversity within the WREZ hubs even when all wind is located in and around Southern California.

Again, it is important to remember that this analysis estimates the magnitude of the change in the value of wind with more diversity. It does not determine whether an increase in diversity should be pursued, as the analysis does not consider the cost of increased diversity.

We chose the high-diversity wind sites by identifying a combination of potential wind sites that has the lowest aggregate variability over the year while still generating adequate annual energy to meet a desired target. In more formal terms, a mathematical program was used to determine which wind sites should be selected to satisfy Eq. 1, following a similar approach described by Palmintier et al. [2008]. This approach is one of many ways that could be used to identify a portfolio with high wind diversity.

$$\begin{aligned} \min_{(u_i \dots u_m)} \quad & \text{Variance} = \sum_{i \in I} \sum_{j \in I} u_i u_j \text{Cov}(W_i, W_j) \\ \text{s.t.} \quad & \sum_{i \in I} u_i E_i \geq \text{Total wind energy target} \end{aligned} \tag{1}$$

Where W is the hourly production of the wind site over a year, E is the annual total energy generated by that site, and u is a binary decision variable to determine whether the site should be included or not.

In practice, solving this problem is very computationally intensive, so several simplifying approximations were used. First, only a subset of all possible sites were used. The Western Wind and Solar Integration Study (WWSIS) wind dataset used in this analysis includes wind generation profiles for more than 30,000 30-MW wind sites in WECC [Potter et al., 2008]. Instead of evaluating all of those sites, we randomly selected 1,000 representative sites that had annual capacity factors above 20%. Scaling parameters were used so that a particular site evaluated in Eq. 1 could represent up to 600 MW of wind (or 20 individual sites that are actually 30 MW in the WWSIS dataset). The variable u, which is used to determine whether a site should be part of the diverse wind portfolio, was split into two variables: one that determines whether a representative site should be included or not and a second that estimates how many of the nearest 20 sites should also be included in the final diverse portfolio. In addition, a supplementary parameter was added to the model to set the maximum number of sites that the program would evaluate (as suggested by Palmintier et al. [2008]).

The modified program was written in AMPL and solved using the CPLEX solver. For a particular wind-penetration level, the model identified which of the possible 1,000 sites should be selected to minimize total variance while generating the desired annual energy. The output also indicated how many of the nearest 20 wind sites should also be included in the final diverse wind portfolio. The number of nearby sites was rounded to the nearest integer between 1 and 20. These results were then used to generate a new high-wind-diversity portfolio for each wind-penetration level, e.g., Figure 4, which shows the portfolio at 40% wind penetration.

Using the Diverse scenario's wind portfolios instead of the Reference scenario's portfolios increases the marginal value of additional wind by about $5/MWh at moderate penetration (10%) and high penetration (30%). At very high penetration, the Diverse scenario's portfolio increases the marginal value of additional wind by more than $10/MWh, Figure 5. Detailed analysis of the Diverse scenario's wind portfolios indicates that the increase in value relative to the

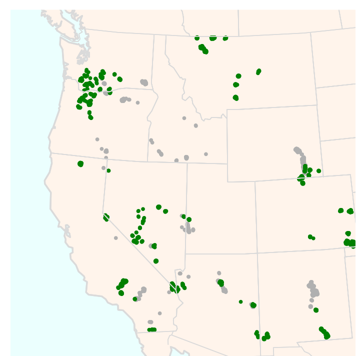

Figure 4: Location of wind sites in the Diverse scenario with 40% wind penetration (locations in the Reference scenario are shown in gray).

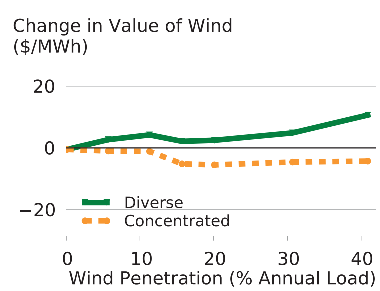

Figure 5: Change in the marginal economic value of wind with geographically concentrated or diverse wind sites relative to the Reference scenario.

Reference scenario is primarily based on an increase in the capacity value for penetrations below 30%. At 40% penetration, the increase in the value of wind for the Diverse scenario's portfolio is due to an increase in energy value followed by a smaller increase in the capacity value and a small decrease in the DA forecast error cost. The increase in energy value is in part due to a reduction in curtailment in the Diverse scenario. Over 3% of the annual wind is curtailed at 40% wind penetration in the Reference scenario, but less than 0.1% is curtailed in the Diverse scenario.

A portfolio with high geographic diversity leads to a higher value of wind due to a reduction in extremes: fewer hours have significant amounts of wind from all wind sites in the portfolio (reducing over-generation and curtailment), and more hours have at least a small amount of wind generation from some sites. The benefit of increased geographic diversity is more pronounced with high wind penetration levels since wind is more likely to affect wholesale prices at high penetration levels.

Figure 6: Location of wind sites in the Concentrated scenario with 40% wind penetration (locations in the Reference scenario are shown in gray).

In contrast, concentrating the wind sites in one geographic region (Figure 6) decreases the value of wind relative to the Reference scenario. Concentrating wind in one region tends to increase the frequency of extremes, where all wind is generating or no wind is generating. Increases in wind generation tend to occur simultaneously in areas where wind speeds are already high and thus while wholesale prices are already low (due to the surplus wind generation). Similarly, wind forecast errors tend to be correlated when wind sites are concentrated. In this case, concentrating wind sites decreases the value of additional wind by around $6/MWh, with wind penetration up to 40%, as shown in Figure 5. The lower value in the Concentrated scenario is driven primarily by an increase in the DA forecast error cost. Since large forecast errors can be technically challenging to manage, concentrated wind also raises concerns about secure system operations.

We do not implement a scenario with a high geographic diversity of PV sites. As explained in a later section, the decline in the value of PV at high penetration levels is due to PV production decreasing when the sun sets and high-price periods shifting into the early evening. Since geographic diversity can do little to affect the timing of the sunset, geographic diversity appears unattractive for stemming the decline in the marginal value of PV found in the Reference scenario.

4.2 *Change in the Marginal Value of VG with Technological Diversity*

The value of one VG technology can depend on the amount of other VG technologies included in a scenario. In the Reference scenario, only one VG technology was added at a time. In this section, we explore how the value of VG changes when the penetration of a different VG technology is increased. First, we estimate the change in the value of wind when the system has 10% PV penetration relative to the value of wind without PV. Next, we examine the change in the value of wind with 10% penetration of CSP with thermal storage (CSP_6). Finally, we look at the change in the value of PV with 10% wind penetration.

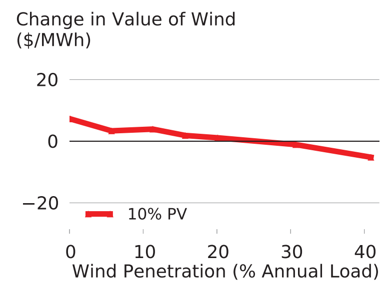

Figure 7: Change in the marginal economic value of wind with 10% penetration of PV relative to the Reference scenario.

To WHAT DEGREE can adding 10% PV penetration mitigate the decline in the value of wind found in the Reference scenario? To evaluate this question, we created a new set of investment, dispatch, and wholesale prices in a scenario with 10% PV and increasing penetration of wind. The resulting marginal value of wind in this new 10% PV mitigation scenario is compared to the value of wind in the Reference scenario in Figure 7.

The marginal value of additional wind when 10% of the energy is served by PV is greater than without 10% PV for wind penetration levels between 0% and 20%. At 0% wind penetration, the marginal value of wind is just over $7/MWh greater with 10% PV than without it; this positive value steadily decreases until it is only slightly greater at 20% wind penetration. Beyond 20% wind penetration, the value of additional wind with 10% PV begins to decrease relative to its value without 10% PV. For wind penetrations above 20%, adding 10% PV is not an effective mitigation measure and instead can reduce the value of additional wind.

The increase in the value of 10% wind with 10% PV is largely due to an increase in the capacity value of wind and a slight increase in the energy value of wind. Since the system is in long-run equilibrium with or without the 10% PV, the average wholesale power prices over the whole year remain at around $70/MWh (sufficient to cover the investment cost of the new CCGT generation). The main difference in the wholesale prices between scenarios with or without 10% PV is the timing of high or low prices. The increase in the capacity value of wind with 10% PV is due to PV shifting the timing of the peak prices into the early evening, when wind generation is somewhat stronger. To illustrate this point, Figure 8 shows load, net load, wind generation, and real-time prices on three days with high loads and scarcity prices (indicating a need for additional generation in those hours). With 10% wind and 0% PV, the net load peaks and prices spike be-

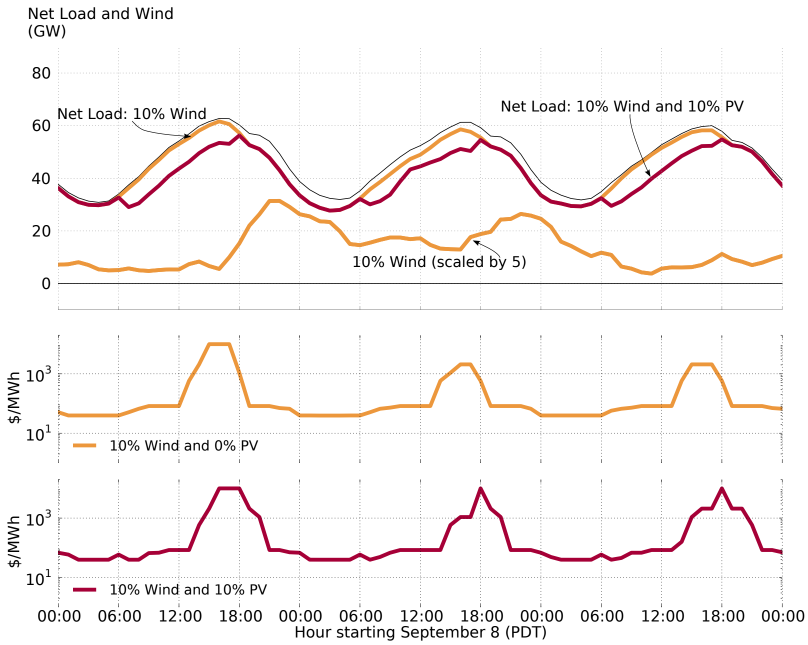

Figure 8: Historical load (thin line), net load, wind generation profile (scaled by a factor of 5 for clarity), and resulting RT price on three peak load days with and without 10% PV penetration.

tween roughly 1 pm and 6 pm. The addition of 10% PV pushes the peak net load closer to 6 pm, and prices spike later between roughly 2 pm and 8 pm. With 10% wind, these later price spikes happen to line up better with wind production on these particular days. While wind is not operating at its full capacity during these price spikes, it is generating more during the early evening, on average, thus the value of wind increases with 10% PV.

To WHAT DEGREE can adding 10% penetration of CSP_6 mitigate the decline in the value of wind found in the Reference scenario? We created a new set of investment decisions, dispatch, and wholesale prices with 10% CSP_6 penetration and increasing penetration of wind. The marginal values of wind in this 10% CSP_6 scenario are nearly identical to the values in the Reference scenario for most wind-penetration levels, Figure 9. Only around 40% wind and 10% CSP_6 does the value of wind begin to decline relative to the value at 40% wind without CSP_6.

Two points help explain why adding CSP_6 does not increase the value of wind. First, the addition of 10% CSP_6 does not shift the timing of scarcity prices. Analysis in the valuation report demonstrates that scarcity prices continue to occur at the same time of day with or without 10% CSP_6, unlike in the case with 10% PV, where scarcity prices shift into the early evening. This is because the addition of

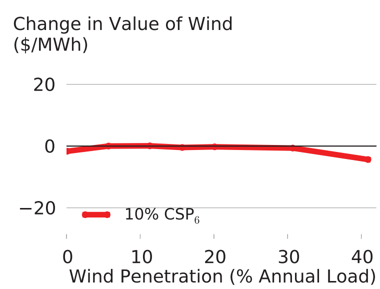

Figure 9: Change in the marginal economic value of wind with 10% penetration of CSP with 6 hours of thermal energy storage relative to the Reference scenario.

thermal storage allows CSP to continue to reduce the net load in the early evening after the sun goes down. Since CSP_6 does not shift the timing of scarcity prices, the value of wind does not increase. Second, wind and CSP_6 generation are not closely related. The timing of wind generation and CSP_6 generation is uncorrelated at 10% penetration of wind and 10% penetration of CSP_6. With increasing wind penetration, the two technologies become more and more negatively correlated, meaning that when wind is generating CSP_6 is less and less likely to be also generating. CSP_6 starts operating in a way to avoid periods with wind, but this does not increase the value of wind. Eventually at 40% wind penetration CSP_6 cannot avoid generating at the same time as wind which lowers prices during periods with wind and decreases the marginal value of wind. Opportunities for CSP_6 to provide system services that might mitigate the impact of wind are rare because times with wind generation are not tied to times with CSP_6 generation.

These results indicate that CSP_6 is not an effective strategy for mitigating the decline in the marginal value of wind with increasing wind-penetration levels. That said, we also find that the addition of 10% CSP_6 does not diminish the value of wind over wind-penetration levels of 0% to 30%.

To WHAT DEGREE can adding 10% penetration of wind mitigate the decline in the value of PV found in the Reference scenario? We created a new set of investment decisions, dispatch, and wholesale prices with 10% wind penetration and increasing penetration of PV. As shown in Figure 10, at very low PV penetration (õ %) the value with or without 10% wind is similar. The high value of PV at low penetration is due to the coincidence of PV generation and scarcity prices in the late afternoon on peak-load days. Wind does not generate much power in the late afternoon, so adding 10% wind does not substantially affect the timing of scarcity prices and the marginal value of PV. However, as PV penetrations increase, adding 10% wind increases the marginal value of PV substantially relative to the Reference scenario, reaching roughly \$7/MWh higher at 10% PV penetration. This increase in the value of PV is almost entirely due to an increase in the capacity value of PV with 10% wind versus the capacity value with no wind. The increase in the capacity value is tied in part to wind generation occurring in early evening (as described earlier) and thus slowing the shift of high-price hours into the early evening with increasing PV.

Above about 10% penetration of PV, the value of PV with 10% wind starts declining toward the value of PV without wind. At 20% PV penetration, the value of PV is again similar with or without 10%

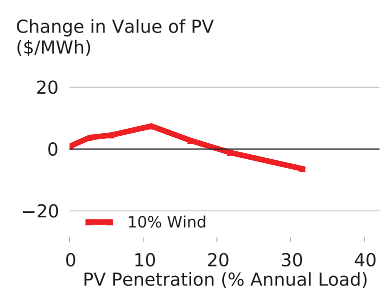

Figure 10: Change in the marginal economic value of PV with 10% penetration of wind relative to the Reference scenario.

wind. At 30% penetration of PV, the marginal value of PV with 10% wind is $6/MWh lower than the value of PV without wind. Wind can, therefore, reduce the decline in the value of PV at moderate PV-penetration levels, but not at 20% or greater PV-penetration levels.

In some cases CSP_6 is thought of as a mitigation measure for PV in the sense that energy from CSP_6 could be substituted for energy from PV while keeping the same penetration level of solar [e.g., Denholm and Mehos, 2011]. In effect, that approach increases the value of solar by decreasing the penetration of PV. In our approach we treat technological diversity in a different manner. Instead of increasing the value of solar by decreasing the penetration of PV, we are interested in measures that mitigate the decline the n value of PV for the same penetration level of PV. CSP_6 is not often thought of as a method to mitigate the decline in the value of PV in this manner, since both technologies generate power during sunny periods. We did not examine a full set of PV-penetration levels with 10% CSP_6, but we did perform a spot check by adding 10% CSP_6 to a scenario with 20% PV then comparing the value of PV to the value in the Reference scenario without CSP_6. The value of PV at 20% penetration is $4.5/MWh lower with 10% CSP_6 than without CSP_6. The decrease in the value of PV when there is also CSP_6 is due to a decrease in the energy value and a smaller decrease in the capacity value of PV. The thermal storage enables CSP_6 to shift much of its generation into hours when PV is not generating (mostly to the early evening hours), but there remain hours when both CSP_6 and PV are generating at the same time, effectively lowering prices during those hours relative to what they would have been with only PV. The cost of AS and DA forecast errors do not change substantially with or without CSP_6.

For moderate penetration levels, technological diversity can increase the value of wind or PV relative to a scenario with just one VG technology. Just as importantly, we find a range of penetration levels where wind and solar technologies do not interfere with each other. The value of additional wind at 20% penetration and 10% PV or 10% CSP_6 (a total VG penetration of 30%) is similar to the value of additional wind at 20% penetration of wind alone. In other words, there is no reduction in economic value of wind at 20% wind penetration with or without 10% penetration of PV or CSP_6. At 30% wind penetration, wind is only slightly less valuable with 10% PV or 10% CSP_6 (a total VG penetration of 40%) than without it. Similarly, the value of additional PV at 20% PV penetration and 10% wind (a total VG penetration of 30%) is almost equal to the value of additional PV at 20% PV penetration alone. This suggests that analysts can evaluate the value of wind or PV at up to 20% penetration with only one technology at a time, knowing that the value of that technology will not decrease if up to a 10% penetration of the other variable technology is added.

Taken together, these scenarios indicate that relatively high penetrations of total VG can be achieved using combinations of wind and solar technologies while maintaining or even enhancing the value of the wind/solar generation compared with the value of using single wind and solar technologies in isolation. However, determining whether to pursue technological diversity as a mitigation measure would require comparing the anticipated increase in value against the potential higher cost of building combinations of technologies to achieve the target penetration level. For example, even though the value of 20% wind may be lower than the value of 10% wind and 10% PV, PV might be more expensive than wind, leading to an overall higher cost. The value changes illustrated in this report are an important part of this full consideration.

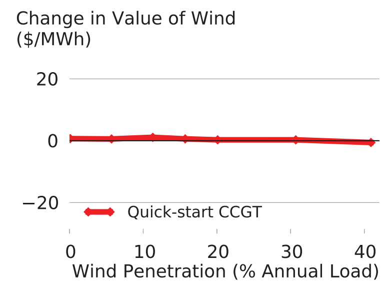

Figure 11: Change in the marginal economic value of wind with all new CCGTs having quick-start capabilities relative to the Reference scenario.

4.3 *Change in the Marginal Value of VG with More-Flexible Generation*

The characteristics of the conventional generation fleet can impact the value of VG. In this section, we examine whether making new CCGT plants more flexible mitigates the decline in the value of wind and solar with increasing penetration. We do this by assuming that new CCGTs, like CTs, have quick-start capability and can be committed and decommitted in real time (in the Reference case we assume that the commitment decisions of all CCGTs are made day-ahead and cannot be changed).[15] The quick-start CCGTs are assumed to maintain the same ramp rate as assumed in the Reference scenario once online. We find new investment decisions, dispatch, and wholesale prices with increasing penetrations of wind and PV assuming that all new CCGTs have quick-start capability, and then we compare the value of wind and PV to the value in the Reference scenario.

For both wind and PV, the change in the value with quick-start CCGTs relative to the value in the Reference scenario is negligible, Figures 11 and 12. This can most likely be explained by the relatively low DA forecast error cost for wind and PV even with CCGTs that need to be committed in the DA (as in the Reference scenario) and the fact that new CCGTs only make up a portion of the total generation mix in California. It could also be due to the way wholesale prices in this model allocate costs and benefits to VG. For example, Figure 12 shows a slight decrease in the value of PV with new quick-start CCGTs relative to the value in the Reference scenario, but

[15] Other options not considered here include rolling-unit commitment [e.g., Tuohy et al., 2007], plant improvements to minimize start-up damages and resulting costs [e.g., Kumar et al., 2012], and retrofits of existing plants to enable quick start or faster ramp rates [e.g., Puga, 2010].

further examination of the "social surplus"[16] with or without quick-start CCGTs always shows a positive (but very small) increase in the social surplus with quick-start CCGTs. This small discrepancy shows that the formulation of wholesale prices can impact the effectiveness of allocating costs and benefits between different market participants. Actual prices used in wholesale markets may produce different results.

[16] Social surplus is the estimate of the total economic benefit to consumers of consuming electricity less the long-run cost of producing electricity.

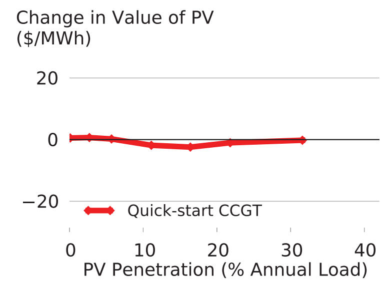

Figure 12: Change in the marginal economic value of PV with all new CCGTs having quick-start capabilities relative to the Reference scenario.

Based on the modeling approach used in this report, making new CCGTs more flexible by allowing commitment in real-time does not appear to be a promising mitigation measure to stem the decline in the value of wind and PV in this region. Perhaps a more promising strategy would be to focus on increasing the flexibility of existing generation or reducing the cost of starting and stopping new and existing thermal power plants. These options are left as suggestions for future research. In addition, the impact of more-flexible generation will depend on the degree of flexibility in the existing generation mix. California has significant amounts of CTs, PHS capacity, and hydropower. In comparison, we found in an earlier analysis of highly concentrated wind in the Rocky Mountain Power Area [Mills and Wiser, 2013] that assuming all new CCGTs had quick-start capability increased the value of wind by up to $6/MWh at 30% wind penetration. The Rocky Mountain Power Area has much less flexible incumbent generation relative to California. As such, results shown in the present paper should not be used to suggest a negligible benefit to generation flexibility overall, and this is an area where future research is recommended.

4.4 *Change in the Marginal Value of VG with Low-Cost Storage*

In this section we quantify how much more valuable wind and PV are when low-cost storage is added to the system. Bulk power storage in this section refers specifically to any storage resource that charges using power from the grid and discharges when providing power to the grid. Storage is modeled as PHS that has a round-trip efficiency of 81%. Storage dispatch is optimized concurrently with the dispatch from all other generation options (including conventional generation and hydro). Storage can be charged or discharged and can also provide AS, specifically, regulation (up or down), spinning reserve, and non-spinning reserve. Additional details on the dispatch of storage are provided in Mills and Wiser [2012]. The size of the assumed storage reservoir is sufficient to provide power for 10 hours at full nameplate capacity.

In the Low-cost Storage scenario, new investment decisions, dispatch, and wholesale prices are found assuming that new PHS could be built with a much lower investment cost than assumed in the Reference scenario. PHS storage was an investment option in the Reference scenario, but the high cost of new PHS storage in the Reference scenario prevented any new additions.[17]

The Low-cost Storage scenario assumes a lower annualized investment cost and fixed O&M cost equivalent to $140/kW-yr, approximately 20% of the cost used in the Reference scenario.[18] Since the cost of storage in the Low-cost Storage scenario is even lower than the annualized fixed cost of a CCGT or CT and new capacity is needed, storage automatically becomes one of the investment options selected in the model. The additions of new PHS capacity chosen by the model with increasing penetrations of wind and PV are shown in Table 1.[19]

With the assumption of low storage-investment costs, 4.4 GW of new storage capacity are built even in the no wind and PV cases. The amount of new storage capacity grows by 57% with 40% wind.[20] The amount of energy that can be stored in the bulk power storage reservoir becomes increasingly important with higher penetrations of wind. Whereas the storage reservoir capacity is only a binding constraint 22 times during the year with 0% wind penetration, the reservoir capacity is a binding constraint 64 times with 30% wind. We only allow storage reservoir capacity to increase in proportion to storage generating capacity (with the proportion fixed at 10 hours of reservoir capacity at full generating capacity). The increase in the number of times that the storage reservoir is a binding constraint indicates that wind might benefit more from proportionally larger storage reservoirs. The relatively small increase in the value of wind with low-cost storage (discussed below) may also be due to the limited storage reservoir capacity.

[17] Both the Reference scenario and the Low-cost Storage scenario include 3.5 GW of existing PHS storage capacity.

[18] This low investment cost is based on the cost estimate for a proposed PHS facility that uses two existing mine pits for the upper and lower reservoirs [Eagle Crest Energy, 2008]. Such a unique situation means that this cost likely represents an extreme lower bound to the cost of PHS.

[19] This new storage is built only after assuming large reductions in the capital cost of storage. Without those cost reductions, no new storage would be built.

[20] At 40% wind penetration, the total new and existing storage capacity is 25% of the nameplate capacity of wind.

New PHS	VG Penetration						
(GW)	0%	5%	10%	15%	20%	30%	40%
Wind	4.4	4.4	4.8	5.4	5.3	5.7	6.9
PV	4.4	3.3	3.5	4.7	6.2	9.8	N/A

Table 1: Investment in new PHS storage capacity with increasing penetration of wind and PV in the Low-cost Storage scenario.

The increase in new storage capacity is largest with 30% penetration of PV: 122% higher than the case with no PV.[21] At lower PV penetrations (<15%), however, the capacity contribution of PV displaces the need for new storage capacity, thereby lowering the amount of new storage relative to a case with 0% PV penetration. By 15% PV penetration, the situation changes, and the amount of new storage capacity increases above what was built in the no PV case. In contrast to wind, the amount of energy that can be stored in the bulk power

[21] At 30% PV penetration, the total new and existing storage capacity is 38% of the nameplate capacity of PV.

storage becomes less important with higher penetrations of PV. The reservoir capacity is only a binding constraint 13 times during the year with 30% PV (compared to 22 times at 0% PV). This suggests that PV requires proportionally smaller reservoirs than the 10 hours of storage capacity assumed here and smaller reservoirs than would be ideal for wind. This is likely due to the diurnal profile of solar where storage would need to be charging for at most half of the day with high solar penetrations. In contrast wind is more variable over longer periods: high wind periods can last for multiple days, leading to a larger benefit from more storage reservoir capacity.

THE INVESTMENTS IN NEW STORAGE change the value of wind relative to the Reference scenario with no new storage. Although additional storage increases the value of wind at nearly all penetration levels, the increase is negligible until 40% wind penetration, Figure 13.

A relatively weak negative correlation between wind generation and generation from storage (existing and new) indicates that storage tends to be charging when wind is generating, and storage tends to be generating when the wind is not blowing, as shown in Table 2, although this relationship does not always hold. This leads to an increase in the energy value of wind due to increases in wholesale prices when storage is charging and wind is generating. Additionally, the energy value of wind increases in part due to a reduction in wind curtailment from 3.2% with 40% wind in the Reference scenario to 0.2% in the Low-cost Storage scenario.

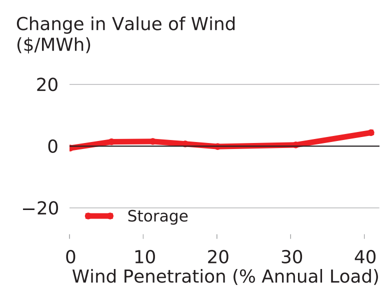

Figure 13: Change in the marginal economic value of wind with low-cost PHS.

At the same time, the assumed low cost of storage capacity reduces the capacity value of wind. Since storage is now the option with the lowest investment cost, it becomes the new capacity resource. Fewer hours with scarcity prices are required to cover the fixed cost of investment in storage compared to the number of hours required to cover the cost of a CCGT. This in turn lowers the capacity value of wind, since wind now generates less power during periods with scarcity prices.

At most penetration levels, the reduction in capacity value is similar to the increase in energy value, leading to only minor changes in the marginal value of wind. At 40% wind penetration, the increase in the energy value with storage is distinctly larger than the reduction in the capacity value. As a result, the marginal value of wind increases by about $4/MWh with storage relative to the Reference scenario.

AT LOW PV PENETRATION, the value of PV declines modestly with

Correlation	VG Penetration						
	0%	5%	10%	15%	20%	30%	40%
Wind	-0.00	-0.11	-0.14	-0.16	-0.18	-0.22	-0.30
PV	0.41	0.12	-0.28	-0.58	-0.74	-0.86	N/A

Table 2: Correlation between VG and the net generation from new and existing storage.

low-cost storage relative to the value of PV in the Reference scenario, Figure 14, owing to a decrease in capacity value. Since the capacity value is a large source of PV value at low penetration levels, a decrease in the number of hours with scarcity prices, as seen with the introduction of low-cost storage, has a negative impact on the value of PV at low penetration. Furthermore, at low PV penetration, storage and PV tend to generate power at similar times, as corroborated by the positive correlation between PV generation and storage discharge in Table 2, resulting in lower wholesale prices at these times and potentially lower energy value.

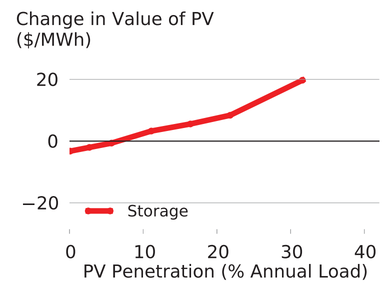

Figure 14: Change in the marginal economic value of PV with low-cost PHS relative to the Reference scenario.

The results are different at higher PV penetrations, where low-cost storage substantially increases the value of PV. Low-cost storage begins to increase PV value relative to the value without low-cost storage at greater than 5% PV penetration. By 30% PV penetration, the marginal value of additional PV is $20/MWh greater with low-cost storage than without.

The increase in the value of PV with low-cost storage is almost entirely due to the increase in the energy value of PV relative to the Reference scenario. The only other contributor to the increase in PV value is a decrease in the cost of DA forecast errors of less than $2/MWh. The energy value of PV increases in part due to a reduction in PV curtailment from 2.9% with 30% PV in the Reference scenario to less than 0.1% in the Low-cost Storage scenario. The strong negative correlation between PV generation and generation from storage (existing and new) at high PV penetrations indicates storage is consistently charging when PV is generating and discharging otherwise, Table 2. The transition from storage and PV generating power at the same time to storage charging when PV is generating and discharging otherwise is apparent during peak-load days in Figure 15. The load on these three days is the highest during the year. On these particular days, storage switches from charging late at night and discharging in the late-afternoon and early evening to charging in the early morning after the sun rises and discharging in the early evening with increasing PV penetration. Charging the storage during the early morning increases power prices in those hours relative to what they would have been without new storage capacity. The increase in prices during this time increases the energy value of PV.

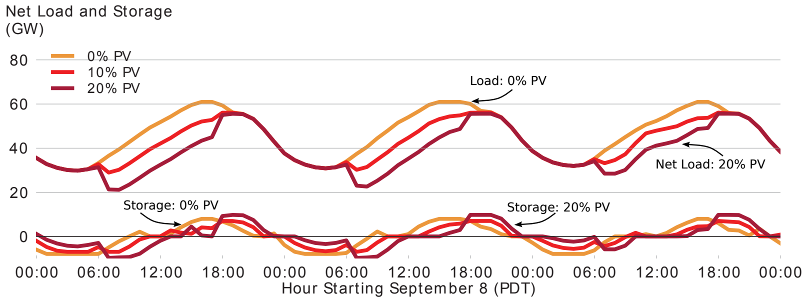

Figure 15: Net load (load less PV) and storage generation on peak days with increasing PV penetration.

4.5 *Change in the Marginal Value of VG with RTP*

In the Reference scenario, all electricity demand is assumed to be indifferent to the DA and RT wholesale market price. This is the situation in much of the United States, where customers pay retail rates that do not vary depending on actual conditions in the DA and RT markets. Increasingly, however, retail rates are including pricing signals to retail customers to indicate periods when electricity consumption is particularly expensive. Large industrial and commercial customers already participate in programs that subject them to prices in wholesale markets in some parts of the United States. Furthermore, the roll-out of smart meters that record demand at 15-minute intervals will enable small commercial and residential customers to transition to retail prices reflecting conditions in the wholesale market.

If retail prices shift from static to dynamic, or RTP, customer demand is also likely to change relative to historical demand patterns. Studies indicate a wide range of estimates of the elasticity of customer demand to changes in power prices [e.g., Taylor et al., 2005, Lijesen, 2007, Boisvert et al., 2007, Zarnikau and Hallett, 2008, Allcott, 2011]. In the RTP scenario, electricity demand is assumed to have a constant own-price elasticity of -0.1,[22] such that a 10% increase in wholesale prices leads to a 1% reduction in demand relative to the historical demand in the same hour of the year.

[22] A constant elasticity of -0.1 is within the range of assumptions used in other studies on the impact of RTP [e.g., Borenstein and Holland, 2005, Sioshansi and Short, 2009, De Jonghe et al., 2012]. In particular Borenstein and Holland [2005] test the impact of RTP assuming a constant elasticity between -0.1 and -0.5 and participation of between 33% and 99% of the load in RTP.

The RTP program is implemented in the model by making demand price elastic and then finding new investment decisions, generation dispatch, and wholesale power prices with price-responsive demand. In the model, both DA and RT demand are price responsive. If DA prices are near average levels, then the price-responsive demand will be close to historical demand when DA commitments of thermal generation are made. If RT prices then rise due to unexpected shortfalls in VG, then the price-responsive demand will be lower than historical demand levels. To be clear, active participation of the demand side in wholesale power markets through RTP, as modeled in this report, does not match tariffs or programs used in practice.[23] The first program to expose residential customers to RTP, for instance, uses the DA market price to set the RTP price for customers prior to the operating day, but does not update that price based on real-time conditions [Allcott, 2011]. The demand response offered by RTP as modeled in this report is a simplified representation of the "idealized" demand-side participation that might be achieved through new designs of RTP programs or combinations of other existing demand-response programs.

[23] The closest analogue would be a large industrial customer that buys electricity from a retail service provider including a direct pass through of the spot market price. The customer would then actively monitor the wholesale price on a RT basis to decide how much power to consume at any time [e.g., Zarnikau, 2010].

One notable feature of implementing RTP is that price spikes become less severe (prices no longer rise to $10,000/MWh) but prices above $500/MWh increase in frequency. A related outcome is that less conventional generation capacity is built in the RTP scenario, since reductions in demand relative to historical levels at time of system need enable a balance between demand and generation rather than relying on new conventional capacity (similar to the results from Borenstein and Holland [2005]). The new wholesale prices with RTP are used to estimate the change in the value of wind and PV relative to the value in the Reference scenario with inelastic demand.

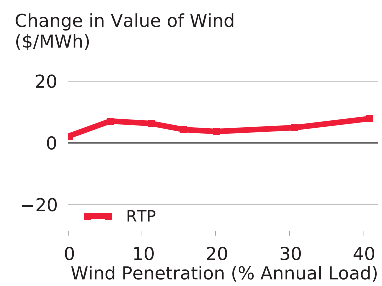

Figure 16: Change in the marginal economic value of wind with RTP and price-responsive demand relative to Reference scenario.

Implementing the RTP program increases the value of wind at all penetration levels, Figure 16. The largest increase in the value of wind relative to the Reference scenario is $7–8/MWh, which occurs both at 5% wind and 40% wind. Less than $2/MWh of this increase in value is due to decreases in the DA forecast error cost with RTP. The remainder of the increase in wind value with RTP is due to an increase in the sum of the energy and capacity values. The capacity value of wind increases because the increase in the number of hours with prices above $500/MWh happens to cover more hours with some wind generation. The energy value increases because price-responsive demand increases relative to historical levels during times with increased wind generation (due to wind's impact on depressing wholesale prices at these times leading to higher load and therefore and increase in wholesale prices).

Table 3: Correlation between VG and demand response provided by RTP.

Correlation	VG Penetration						
	0%	5%	10%	15%	20%	30%	40%
Wind	-0.03	-0.17	-0.31	-0.39	-0.44	-0.54	-0.69
PV	0.27	0.09	-0.16	-0.42	-0.59	-0.79	N/A

Tracking the correlation between demand response and wind generation illustrates the degree to which demand-side decisions are influenced by wind. Demand response in this context is defined as the difference between the historical load profile assuming that demand is not influenced by wholesale power prices and the price-responsive load profile. Positive correlation between demand response and wind generation indicates that price-responsive demand leads to lower demand at the same time that wind is generating electricity, while negative correlation indicates that price-responsive demand leads to higher demand when wind is generating. The correlation between demand response and wind at different penetration levels, Table 3, indicates that wind and demand response are largely uncorrelated at very low wind penetration, but that price-responsive demand increases during times with high wind at higher penetration. Contrary to most demand-response programs that have historically been designed to decrease demand, these results indicate that the value of wind is increased by shifting demand to, or even increasing demand during, times when wind is generating power.

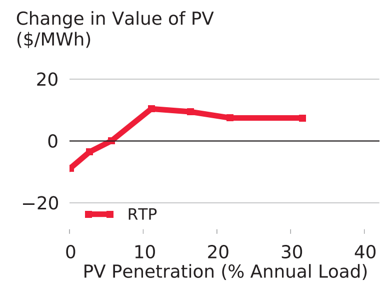

Figure 17: Change in the marginal economic value of PV with RTP and price-responsive demand relative to the Reference scenario.

As with wind, implementing the RTP program increases the value of PV at high penetration levels; in contrast to wind, the RTP program decreases the value of PV at low penetration levels (<5%), Figure 17. The reason for the decrease in PV value with RTP at low penetration is similar to the reason for the decrease in PV value with low-cost storage. Implementing RTP reduces the cost of capacity and the duration of very high price spikes. At low PV penetration, this decrease in high prices lowers the revenue earned by PV. At 10% PV penetration, however, implementing RTP increases the value of PV by up to $10/MWh. At even higher penetration levels, the increase in PV value from RTP is closer to $7–8/MWh.

At low PV penetration, PV and the demand response from RTP are positively correlated, as shown in Table 3, indicating that RTP decreases demand at the same time that PV is generating power. Lower demand leads to lower wholesale prices and therefore lowers the marginal value of PV at low penetration. At 10% PV penetration and above, PV and demand response are negatively correlated, indicating an increase in demand when PV is generating. At 30% penetration, the correlation between PV and demand response is almost -0.8, substantially more negatively correlated than wind and demand response at 30% penetration. On average over the entire year, RTP increases the total demand by only 0.1% at 10% PV penetration but by 3.2% at 30% PV penetration. Nearly all of the increase in demand occurs during daytime hours when PV is producing power, particularly in spring months. Such changes in consumption patterns may require end-use control technologies or customer behaviors that differ from those in traditional demand-response programs, which primarily reduce demand during summer afternoons. Midday electric vehicle charging might be well suited to increasing customer demand during times with high PV production.

The characteristics of the modeled demand response provided by RTP on peak-load days with increasing PV penetration can be illuminated further by examining a time series of the historical load, the remaining load after implementing RTP, and the difference between historical load and the load with RTP (i.e., the demand response), Figure 18. Implementing RTP without PV leads to demand response that is greatest in the late afternoon and effectively levels the peak demand on all three days. Increasing PV penetration shifts the demand response provided by RTP from late afternoon into early evening. The demand response does not entirely disappear during the daylight hours—times when PV is generating. Thus, even though the hours with highest prices shift into the early evening, high prices still occur during times with PV generation, thereby helping to maintain the value of PV with increasing penetration.

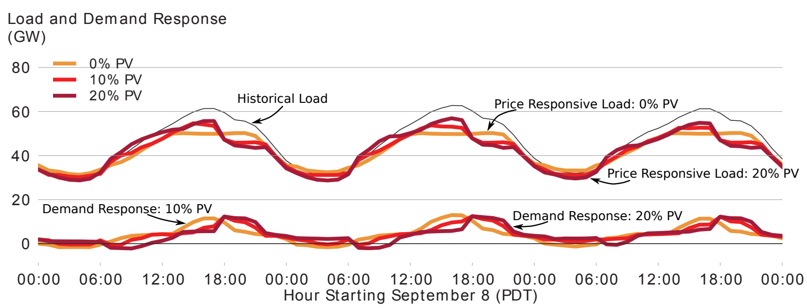

Figure 18: Historical load (thin line), price-responsive load, and effective demand response on peak days with increasing PV penetration.

Demand-response strategies for peak-load days, such as pre-cooling, which shifts cooling loads away from the peak to earlier in the day, may need to be adjusted in scenarios with high PV penetration. At 0% PV penetration, a pre-cooling strategy would aim to reduce demand before around 6 pm on peak-load days. With high PV penetration, the pre-cooling would need to reduce demand between about 6 pm and 9 pm. High PV penetrations may also shift the focus from one customer class to another, depending on the load profiles of different customer classes. In some regions, commercial loads tend to peak earlier in the day while residential loads peak later in the evening. In that case, demand-response programs could target commercial customers at low PV penetration but shift to residential customers at high PV penetrations. Many other factors go into the design of demand-response and retail-pricing programs, but this analysis suggests that expectations for future PV penetration levels might be an important consideration.

5 Change in the Value of Mitigation Measures with Increasing VG

Now that we have examined the impact of mitigation measures on the value of VG, a related question is whether it makes economic sense to implement these mitigation measures. We do not fully address that question, mostly due to a lack of comparable data on mitigation-measure costs. However, we indirectly provide insights by asking: How much does the marginal economic value of mitigation measures change with increasing penetration of VG? An increase in the economic value of mitigation measures with increasing VG penetrations indicates that a mitigation measure may become more economically attractive with increased VG. The more a mitigation measure's marginal value increases, the higher the cost of implementing it can be while still being economically attractive (or the lower the subsidy would need to be to incentivize the measure).

We develop a metric for each mitigation measure showing the change in the measure's marginal economic value with increasing VG penetration before mitigation is implemented. The marginal value metrics are all based on the long-run equilibrium prices from the unmitigated Reference scenario in the valuation report.

The general principle for developing these metrics is consistent across all mitigation measures: each metric is based on estimating the short-run profit that a resource with the same hourly profile would have assuming that the resource does not impact wholesale prices in the Reference scenario (i.e., the resource is a price-taker). However, the specific metric used for each scenario differs based on the characteristics of the mitigation measure. In the case of bulk power storage, for example, the metric is the short-run profit that storage would earn based on the prices from the Reference scenario at a particular level of VG penetration. First, the DA energy prices, RT energy prices, and AS prices from the Reference scenario are used to create a DA schedule and RT dispatch for storage. The marginal economic value of storage is then estimated as the short-run profit of storage based on those schedules and prices. The change in the value of storage with increasing penetration of VG is estimated by calculating the short-run profit of storage using prices and schedules from scenarios with different VG-penetration levels. This metric only reflects the marginal economic value of a mitigation measure before it is implemented, since the prices used in this analysis are derived from the unmitigated Reference scenario.

Similar to the presentation in the previous section, we start by describing the change in the value of geographic diversity with increasing penetration of VG, then address the change in the value of technological diversity. Next we examine the value of more flexible generation, specifically CCGTs that can be started in real-time and CCGTs with a fast ramp rate. We then examine the change in the value of storage and real-time pricing with increasing penetration of VG.

5.1 *Change in the Marginal Value of Geographic Diversity*

Consider a situation in which wind is increasingly added to the power system based on the wind-site locations used in the Reference scenario. As this wind is added, we want to know if the marginal value of wind from the high-diversity sites described earlier (Diverse sites) would appear greater than the marginal value of wind at the Reference scenario sites and how this changes with penetration. To answer this question, we estimate the marginal value of wind at the diverse sites using the DA, RT, and AS prices from the Reference scenario. We then compare the marginal value of wind from the diverse sites to the marginal value of wind from the Reference scenario sites, Figure 19. The marginal value of wind at the diverse sites is estimated using wholesale prices from the Reference scenario and the generation profiles at the diverse sites.

As wind is added from the sites in the Reference scenario, the marginal value of wind from the diverse sites becomes increasingly greater than the marginal value of wind from the sites in the Reference scenario. This indicates that, if a wind developer were to consider two sites, one with a generation profile similar to the wind sites in the Reference scenario and one with a profile similar to the diverse sites, then the diverse site would have a higher marginal value per unit of energy generated (assuming the wind output is sold into a power market with the long-run equilibrium prices identified in the Reference scenario). This greater value increases with increasing penetration of wind from the Reference scenario sites to the point that diverse sites see a premium of $7–8/MWh. A developer could then compare this premium for siting at a higher-value location to the potential costs of that location. These potential costs could include increased transmission costs (if the site is further from California loads) or lower annual wind production, both of which could be larger than the value premium. Only when the value premium exceeds any increase in costs to access the diverse sites would the developer choose the diverse site on economic grounds.

In addition to the diverse sites, which were selected to minimize the aggregate variability of a portfolio of wind sites, many other potential wind sites are available in the Western United States. We selected 10,000 wind sites at random from the list of potential sites in

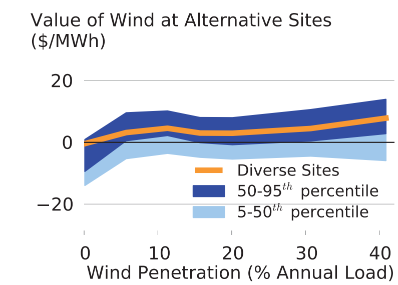

Figure 19: Difference between the marginal value of wind at alternative wind sites relative to the value of wind at sites used in the Reference scenario.

WECC from the WWSIS data set and calculated the marginal value of wind at each of these alternative sites. The difference between the marginal economic value of wind from the alternative sites and the value of wind in the Reference scenario at each wind-penetration level is shown in Figure 19. We show the value of wind from the 50^{th} to the 95^{th} percentile of sites relative to the value of wind in the Reference scenario as the dark blue region; in other words, the top of the dark blue range indicates the marginal value of the 500 highest-value wind sites out of the 10,000 alternative sites. The value of wind from the 5^{th} to the 50^{th} percentile is shown in light blue.

The choice of wind sites becomes more important at higher penetration levels. If a wind developer could choose from any of these potential 10,000 sites, then at low wind penetration the range in value between sites would be about \$15/MWh (5^{th} to 95^{th} percentile or top of the dark blue to bottom of the light blue). At 40% wind penetration, this range increases to \$20/MWh. This indicates that high-value sites become more valuable relative to low-value sites at high wind penetration. At 40% wind penetration, the developer would find it economically attractive to build at a high-value site (in the 95^{th} percentile) instead of a low-value site (in the 5^{th} percentile) as long as any reduction in annual production or increase in transmission costs (or any other site-specific differences in costs) did not exceed \$20/MWh. Given the potential wide variation in wind quality and access to transmission capacity, considerations about geographic diversity are not likely to dominate siting decisions at present. Wind resource quality and transmission availability are likely to be more important factors.

In contrast to the wind findings, the difference in the value of PV at alternative sites appears to decrease with increased PV penetration. We calculated the marginal value of PV from 2,000 sites pulled at random from various southwest WREZ hubs using the prices from the Reference scenario. Figure 20 plots the range of the marginal value between the 5^{th} and 95^{th} percentile of these alternative sites.

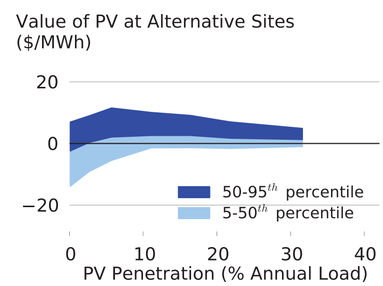

Figure 20: Difference between the marginal value of PV at alternative PV sites relative to the value of PV at sites used in the Reference scenario.

At low penetration, the difference in value between low-value sites and high -value sites (5^{th} to 95^{th} percentile) is around \$21/MWh. At low PV penetration, different choices of PV sites will lead to different values of PV. A site that is cloudy during summer afternoon peak-load times, for example, might have a substantially lower value than a site that is clear during summer afternoons.

At high PV penetrations, in contrast, the marginal value of PV from any of the potential sites is similar to the marginal value of PV at the sites chosen for the Reference scenario. The difference in value between low-value and high-value sites is only \$6-7/MWh (5^{th} to 95^{th} percentile). This indicates that no matter what site is chosen for the next increment of PV—near or far from other PV sites—the marginal value of that site will be similar to the value found in the Reference scenario.

The narrowing of the value of PV from different sites with high PV penetration is due to wholesale prices consistently dropping in most hours with PV production and high prices shifting to hours after the sun has gone down. Since geographic diversity does not change the timing of sunrise and sunset (and situating plants further east of California only shifts the timing of sunset for those PV locations to earlier hours), geographic diversity provides little opportunity to mitigate the decline in the value of PV. Furthermore, while geographic diversity can mitigate costs associated with DA forecast errors and short-term variability that affects the need for AS, these costs do not strongly increase with increasing PV penetration. As such, these shorter-timescale issues are not a major contributor to the decline in the value of PV, hence mitigating them through additional geographic diversity will not address the root cause of the changes in PV value with increasing penetration.

5.2 *Change in the Marginal Value of Technological Diversity*

In the case of technological diversity, we use the wholesale power prices from the Reference scenario to examine the change in the economic value of the first increment of one technology as the penetration of another is increased. For example, we explore how the value of the first increment of wind changes when there is no PV compared to when there is increasing PV on the system. An increase in the value of wind as PV penetration increases indicates that technological diversity becomes more attractive with higher VG penetration than with low VG penetration.

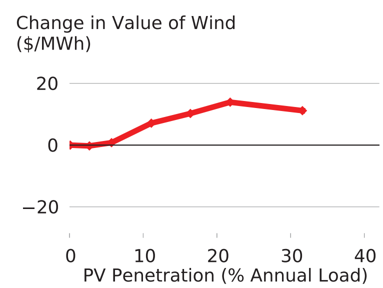

Figure 21: Change in the marginal economic value of wind at 0% penetration with increasing penetration of PV.

The value of the first increment of wind with increasing penetrations of PV is found based on the wholesale prices from the Reference scenario, Figure 21. The value of the first increment of wind increases as more PV is added to the system, similar to the findings from Lamont [2008].[24] Intuitively this increase in the value of wind with PV is due to the addition of PV shifting the high-price periods into the early evening. In this particular case, wind tends to be stronger in the early evening than it is earlier in the day.

[24] Lamont [2008] uses 2001 weather data for load, wind, and PV. This analysis uses 2004 weather data. The similar findings between the two papers suggest the results are not unique to one particular weather year.

In particular, Figure 21 shows that the value of wind at 0% penetration as more PV is added increases beyond what it would have been without PV by about $5/MWh at medium PV penetration (10% penetration) and about $10/MWh at high PV penetration (20% penetration). At 30% PV penetration, the value of the first increment of wind is still higher than it would be without PV but lower than the value at 20% PV penetration.

AGAIN USING THE wholesale power prices from the Reference scenario, the value of the first increment of wind is found with increasing penetration levels of CSP_6, Figure 22. The value of the first increment of wind does not change significantly at any penetration level of CSP_6.

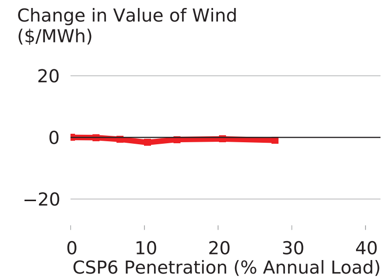

Figure 22: Change in the marginal economic value of wind at 0% penetration with increasing penetration of CSP with 6 hours of thermal energy storage.

NEXT WE EXAMINE the value of the first increment of PV as more wind is added to the system, Figure 23. The value of the first increment of PV does not change significantly with increasing wind penetration, again matching the findings from Lamont [2008].

In the Reference scenario, the high value of PV at low penetration is primarily due to the high capacity value and energy value of PV. These results demonstrate that PV continues to have a high value at low penetration, even with large increases in the penetration of wind. The value of the first increment of PV does not, however, notably increase due to the addition of wind, whereas this was the case for the first increment of wind due to the addition of PV.

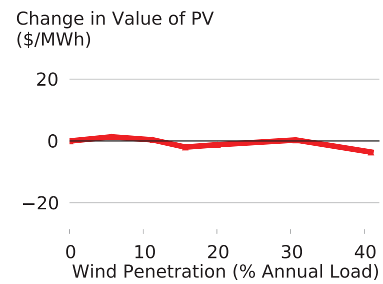

Figure 23: Change in the marginal economic value of PV at 0% penetration with increasing penetration of wind.

THE VALUE OF THE FIRST increment of PV decreases with increasing penetration of CSP_6, particularly with CSP_6 penetrations above 10%. The wholesale prices from the Reference scenario with increasing CSP_6 penetration begin to decrease during the middle of the day in the summer, thereby also decreasing the value of the first increment of PV, Figure 24. By 30% CSP_6 penetration, the decrease in the value of PV is nearly $30/MWh lower than found without CSP_6. This decrease in value is primarily due to a decrease in PV capacity value. The capacity value of PV at 0% penetration is only $11/MWh with 30% penetration of CSP_6, whereas the capacity value of PV at 0% penetration without CSP_6 is $37/MWh. The energy value of PV also decreases as more CSP_6 is added. The decrease in the value of the first increment of PV with increasing penetrations of CSP_6 suggests that these two solar technologies can "crowd" each other out of the market.

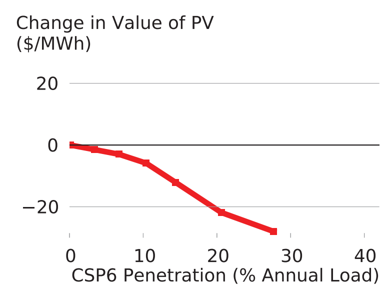

Figure 24: Change in the marginal economic value of PV at 0% penetration with increasing penetration of CSP with 6 hours of thermal storage.

5.3 Change in the Marginal Value of More-Flexible Generation

Here, we examine the degree to which more-flexible generation increases in value with increasing penetration of wind and solar. Two separate options are considered in order to make new CCGT investments more flexible. One option assumes that new CCGTs have very high ramp rates when they are online, while maintaining the assumption that they must be committed in the DA.[25] The second option assumes new CCGTs have quick-start capability and can be committed and decommitted in real time. The quick-start CCGTs are assumed to maintain the same ramp rate as assumed in the Reference scenario once online.

[25] The ramp rate for new CCGTs was 39%/hour in the Reference scenario and 200%/hour for the fast-ramping CCGTs.

The wholesale prices and the dispatch of the fast-ramping CCGT are used to estimate the short-run profit in the Reference scenario with increasing wind and PV, Figure 25. Increasing the ramp rate of new CCGTs moderately increases the value of the CCGTs, as reflected in the short-run profit of those plants, but only for high penetrations of wind and PV.

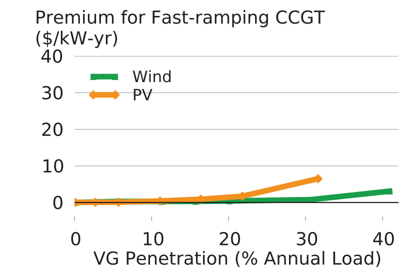

Figure 25: Change in the short-run profit premium for a fast-ramping CCGT relative to a CCGT without fast ramping.

With near-zero or low penetrations of wind and PV, enabling new CCGTs to ramp more quickly does not increase the value relative to the normal CCGT. As the penetration of PV increases beyond 20%, the premium for the fast-ramping CCGT increases by less than $10/kW-yr or roughly 5% of the annualized fixed cost of the new CCGT. The premium for the fast-ramping CCGT is roughly half that value for 40% penetration of wind.

In contrast, the quick-start CCGT has about a $5/kW-yr premium in value relative to the normal new CCGT even without wind or PV added to the system. This premium for a quick-start CCGT increases with increasing penetrations of wind and PV, Figure 26. At 30% penetration of wind or PV, the quick-start CCGT is worth approximately $20/kW-yr more than a normal CCGT. The premium increases to roughly $33/kW-yr, or 16% of the annualized fixed cost of a CCGT, by 40% wind penetration.

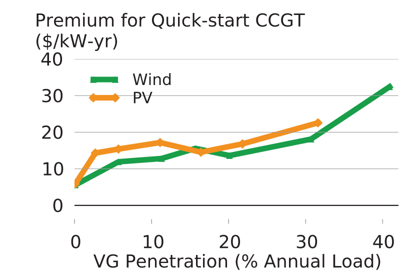

Figure 26: Change in the short-run profit premium for a quick-start CCGT relative to a CCGT without quick start.

A portion of this increase in the premium, particularly with 40% wind, is due to the ability of quick-start CCGTs to take advantage of scarcity prices during events that were unforeseen in the DA. For example, with 30% wind there are seven times in the year when prices are below $100/MWh in the DA market (suggesting adequate generation capacity) while prices in the RT market for the same hour rise above $500/MWh (suggesting scarcity in the RT market). A quick-start CCGT can start in the RT to earn high revenues even if it were not committed in the DA. With 40% wind, there are 16 such unforeseen events. A larger number of events indicates more opportunity for a quick-start CCGT to earn a premium over a CCGT whose commitment is fixed in the DA market.

Both the quick-start and fast-ramping capabilities increase the value of CCGTs relative to the value of the normal CCGT. Both of these forms of increased flexibility increase in value with increasing wind and PV. This indicates that wholesale market prices, at least as they are modeled in this analysis, reflect a premium that is paid to more-flexible generation, and the premium increases with penetrations of wind and PV. Based on these results, the wholesale market prices reflect a higher premium for quick-start CCGTs than the premium for fast-ramping CCGTs with or without increased wind and PV penetration. Overall these results imply that more-flexible CCGTs will become more competitive than less-flexible CCGTs with increasing penetration of wind and PV. Additional research is warranted to determine if such a premium exists with power plants and wholesale prices in actual power markets, particularly markets that are not designed to be "energy only" markets as modeled in this analysis.

5.4 *Change in the Marginal Value of Bulk Power Storage*

In this section, we quantify the degree to which bulk power storage becomes more economically attractive with increasing wind and PV. To examine the change in the value of storage, we use the wholesale prices from the Reference scenario to calculate the short-run profit storage would earn for different levels of wind and PV penetration. Storage is assumed to buy and sell power at the wholesale power price in the DA and RT markets. Storage can also provide regulation, spinning reserves, and non-spinning reserves. We make the simplifying assumption that storage has perfect foresight from one hour to the next within the DA market (or from one hour to the next within the RT market).[26] This simplifying assumption tends to overstate the short-run profit of real storage, which has imperfect foresight from one hour to the next in the DA or RT market. In the Reference case, no new storage is built due to its high investment cost. The value of storage reported here, therefore, represents the marginal value before any new storage is added to the system.

[26] On the other hand, we assume that storage does not know how prices will change between one particular hour in the DA market and that same hour in the RT market.

Even without the addition of wind or PV, storage has substantial value, about $198/kW-yr, in the Reference scenario. Almost 85% of the value is from the capacity value of storage. The remaining 15% of the value of storage is split between energy value (2/3) and AS (1/3). The value of storage increases with increasing penetrations of wind and PV, Figure 27. At 30% penetration of PV, the value of storage increases by over $100/kW-yr relative to the value with 0% PV, while at the same penetration of wind the value of storage increases by slightly less than half that value.

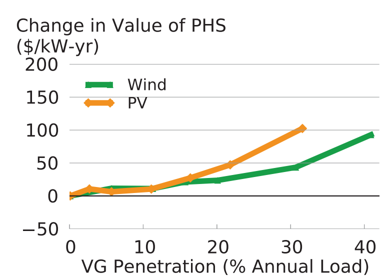

Figure 27: Change in the short-run profit of PHS with increasing VG.

The increase in the value of storage with increasing PV is predominantly driven by an increase in the energy value of storage (e.g., energy arbitrage between different hours of the day).[27] Wholesale prices decrease to $0/MWh in nearly 10% of the hours of the year with 30% PV penetration, while prices never go to $0/MWh with 0% PV. Increases in the number of hours with very low prices increase opportunities for profitable arbitrage with storage. The capacity

[27] These arbitrage opportunities should be relatively predictable with increasing PV due to the regular diurnal PV generation pattern.

value remains high but does not increase much with increasing PV penetration.

The increase in the value of storage with wind is primarily driven by an increase in the value of managing DA forecast errors (e.g., arbitraging between the DA and RT markets).[28] With 30% wind, wholesale prices approach $0/MWh much less frequently than they do with 30% PV. The situation does change at 40% wind, where the frequency of low prices increases to the point that they occur as often as with 30% PV (roughly 10% of the hours of the year). At these very high wind penetration levels the value of storage is further increased by energy value derived from the arbitrage opportunities between high and low priced hours in the DA market.

[28] Capturing this value with storage will be more challenging due to the uncertainty in DA forecasting.

These results suggest that increasing wind and PV penetration make investment in storage more attractive than it is without high wind and PV penetration. However, at least in the Reference scenario, this higher value is not sufficient to make up for the high investment cost of storage.

5.5 *Change in the Marginal Value of RTP*

Here we estimate how attractive RTP would be with and without increasing penetration of wind and PV. It is not clear how to estimate the economic value of an RTP program and then how the value of RTP changes with increasing penetration of wind and PV. To avoid a detailed exploration of this question, we instead develop a simple metric and quantify the percentage change in that metric with increasing wind and PV. The metric used to quantify the value of RTP is the short-run profit that would be earned by a demand-response resource that participates in both the DA and RT markets. The demand response is the difference in the historical demand and the price-elastic demand assuming a constant price elasticity of -0.1. This demand response is then multiplied by the DA market price in the Reference scenario. RT demand response is any further change in the demand response based on the wholesale prices in the RT market. Any increase in value based on RT deviations of demand response from the DA schedule are based on the RT prices. This short-run profit of demand response is used as a proxy for the value of RTP for any wind and PV penetration level in the Reference scenario.

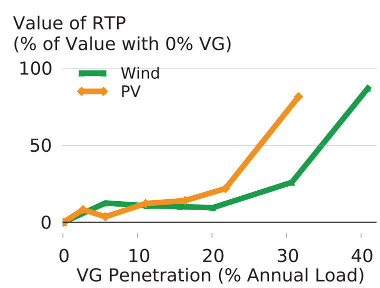

Figure 28: Change in the benefit of RTP with increasing VG as a percentage of the benefit of RTP at 0% VG.

The value of RTP with increasing wind and PV as a percentage of the value of RTP with 0% VG penetration increases dramatically for VG penetrations greater than 20%, Figure 28. At 30% penetration of PV and 40% penetration of wind, the marginal value of RTP is 80–90% more than the value without wind or PV. The majority of the increase in the value of RTP at high penetrations of wind and PV comes from the additional flexibility in RT (i.e., value derived from helping to manage forecast errors between RT and DA). Up to 5% PV penetration or 20% wind penetration, the additional flexibility of RTP between RT and DA markets contributes less than about 6% of the value of RTP. At higher penetrations, the RT contribution eventually increases to around 40% of the value of RTP. Such heavy reliance on rapid and flexible responses to needs that were unforeseen in the DA is a large departure from many current U.S. RTP and demand-response programs. Additional research into the design of programs, technologies, and policies that would provide such flexibility from the demand side may be warranted.

6 Conclusions

Our earlier work found declines in the marginal economic value of wind and PV with increasing penetration [Mills and Wiser, 2012]. As was found in Germany by Hirth and Ueckerdt [2013], a number of mitigation measures can moderate, but not eliminate, these reductions in value.

The largest increases in the value of wind relative to the unmitigated Reference scenario at penetration levels above 20% occur with increased geographic diversity in wind sites, implementation of RTP for retail sales, and the availability of low-cost bulk power storage. The largest increases in the value of PV above 10% penetration occur with the availability of low-cost bulk power storage and RTP. One challenge is that interactions between bulk power storage, RTP, and PV will change depending on PV penetration levels. Both low-cost bulk storage and RTP reduce the cost of meeting peak loads on summer afternoons. This reduces the value of PV at penetrations below 5%, even though the same mitigation measures are found to increase the value of PV relative to an unmitigated case at higher penetration levels.

For both wind and PV, deployment of RTP programs will be driven by myriad factors, but the attractiveness of RTP increases substantially with high ($> 5\%$) wind and PV penetration relative to the attractiveness without wind and PV. That said, the character of the ideal demand response provided by RTP in high wind and PV penetration scenarios does not look the same as the demand response provided without wind and PV. For both wind and PV, the ideal demand response provided by RTP increases demand during times when wind and PV are generating power. Moreover, on peak-load days, the reduction in demand from RTP shifts from the afternoon into the early evening as PV penetration increases. The increase in attractiveness of RTP and the increase in the value of wind and PV found in this analysis will require that demand response has the flexibility to provide response depending on when wind and PV are available. Customers that are considering switching to RTP programs or designers of RTP programs should similarly consider the benefits of this flexibility. Additional research in this area would be valuable.

Low-cost storage is also promising for increasing the value of wind and PV at high penetration, although the increase in PV value is substantially larger than the increase in wind value. This analysis only considered one type of storage: PHS with 10 hours of reservoir capacity. Therefore, the estimated changes in the value of wind and PV assume this type of storage is somehow made available with a low investment cost. The increase in the value of PV with storage is driven by an increase in the energy value, suggesting that multiple hours of storage capacity will be needed to do diurnal shifts to achieve a similar increase in the value of PV. For wind, the analysis suggests that more than 10 hours of storage would be beneficial. Future research on the right amount of storage capacity and ways to reduce storage cost would be beneficial. The cost of storage must be greatly reduced from EIA's current estimate of PHS cost to justify investment in new storage capacity.

Increased geographic diversity produces a large increase in the value of wind. With increasing penetration, wind at geographically diverse sites could earn higher revenue than wind sited closer to existing wind. This increase in the value of wind will need to be weighed against any increased costs due to additional transmission or lower wind quality associated with these alternative sites. In contrast, increasing the geographic diversity of PV beyond the degree of diversity already represented in the Reference scenario does not appear to have the potential to substantially increase the value of PV at high penetration levels.

This analysis identified some apparently unpromising measures for increasing the marginal value of wind and PV relative to the Reference scenario without those measures. The premium for more-flexible new CCGTs increases with wind and PV penetration. On the other hand, assuming that all new CCGTs could be started in RT does not significantly increase the value of wind or PV. The valuation report, on the other hand, found that relaxing all operational constraints on new and existing generation capacity increases the value of wind and PV. In combination, these results suggest that the focus should be on increasing the flexibility of existing conventional generation, not just new generation. The relatively high amount of flexibility in California is important to note, the impact of more flexible generation will be different in other regions.

We found interesting interactions between different VG technologies in the technological diversity cases. At 10% penetration of wind and 10% penetration of PV, the marginal value of PV increases by as much as $7/MWh relative to the Reference scenario. Different combinations of wind and solar do not produce similar increases in the value of wind or PV. More importantly, however, various combinations of VG technologies were found that do not decrease the value of wind or PV relative to the Reference scenario, even though the aggregate proportion of annual demand met by VG technologies is higher. Specifically, combinations of 10–20% wind and 10% PV or 10% CSP_6 have no lower value than wind alone. Similarly, combinations of 10–20% PV with 10% wind have no lower value than PV alone. These results suggest that if 10–20% wind or PV penetrations can be economically justified on their own, then 30% penetration from combinations of wind and solar technologies would be similarly justified.

Throughout this analysis, only one mitigation measure is implemented at a time. In some cases, the benefits of different mitigation measures are caused by similar factors (e.g., increases in the value of wind at high penetration with RTP and storage are both linked to an increase in demand during times when wind is generating). As such, the change in the value of wind or PV from simultaneously implementing multiple mitigation measures is not expected to be the same as the sum of the change in value from each mitigation measure implemented in isolation. Interactions between mitigation measures is an area for future research.

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