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Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California

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Environmental Energy Technologies Division

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Abstract

We estimate the long-run economic value of variable renewable generation with increasing penetration using a unique investment and dispatch model that captures long-run investment decisions while also incorporating detailed operational constraints and hourly time resolution over a full year. High time resolution and the incorporation of operational constraints are important for estimating the economic value of variable generation, as is the use of a modeling framework that accommodates new investment decisions. The model is herein applied with a case study that is loosely based on California in 2030. Increasing amounts of wind, photovoltaics (PV), and concentrating solar power (CSP) with and without thermal energy storage (TES) are added one at a time. The marginal economic value of these renewable energy sources is estimated and then decomposed into capacity value, energy value, day-ahead forecast error cost, and ancillary services. The marginal economic value, as defined here, is primarily based on the combination of avoided capital investment cost and avoided variable fuel and operations and maintenance costs from other power plants in the power system. Though the model only captures a subset of the benefits and costs of renewable energy, it nonetheless provides unique insights into how the value of that subset changes with technology and penetration level.

Specifically, in this case study implementation of the model, the marginal economic value of all three solar options is found to exceed the value of a flat-block of power (as well as wind energy) by $20–30/MWh at low penetration levels, largely due to the high capacity value of solar at low penetration. Because the value of CSP per unit of energy is found to be high with or without thermal energy storage at low penetration, we find little apparent incremental value to thermal storage at low solar penetration in the present case study analysis. The marginal economic value of PV and CSP without thermal storage is found to drop considerably (by more than $70/MWh) as the penetration of solar increases toward 30% on an energy basis. This is due primarily to a steep drop in capacity value followed by a decrease in energy value. In contrast, the value of CSP with thermal storage drops much less dramatically as penetration increases. As a result, at solar penetration levels above 10%, CSP with thermal storage is found to be considerably more valuable relative to PV and CSP without thermal storage. The marginal economic value of wind is found to be largely driven by energy value, and is lower than solar at low penetration. The marginal economic value of wind drops at a relatively slower rate with penetration, however. As a result, at high penetration, the value of wind can exceed the value of PV and CSP without thermal storage. Though some of these findings may be somewhat unique to the specific case study presented here, the results: (1) highlight the importance of an analysis framework that addresses long-term investment decisions as well as short-term dispatch and operational constraints, (2) can help inform long-term decisions about renewable energy procurement and supporting infrastructure, and (3) point to areas where further research is warranted.

Executive Summary

Overview

The variable and unpredictable nature of some renewable resources, particularly wind and solar, leads to challenges in making resource procurement and investment decisions. Comparisons of generating technologies are incomplete when simply based on the relative generating cost of those technologies (i.e., comparisons based on levelized cost of energy (LCOE)). A missing part of simple cost comparisons is an evaluation of the economic value, or "avoided costs", of energy generated by different generating technologies. To better understand the economic value of wind and solar and how it changes with increasing penetration, this report uses a unique modeling framework to examine a subset of the economic benefits from adding wind, single-axis tracking photovoltaics (PV), and concentrating solar power (CSP) with and without six hours of thermal energy storage (CSP_6 and CSP_0, respectively). These variable renewable generation (VG) technologies are added one at a time, leaving examination of the benefits of adding combinations of VG technologies to a future report. In addition to the VG technologies, a case where the penetration of a flat block of power that delivers a constant amount of electricity on a 24×7 basis is increased in a manner similar to the VG cases for comparison purposes.

The subset of the benefits of variable renewable generation examined in this report is termed the marginal economic value of those resources. Benefits are primarily based on avoiding costs for other non-renewable power plants in the power system including capital investment cost, variable fuel, and variable operations and maintenance (O&M). These avoided costs are calculated while accounting for operational constraints on conventional generators and the increased need for ancillary services when adding variable renewable generation. Furthermore, the economic value reported here is the marginal economic value based on the change in benefits for a small change in the amount of variable renewable generation at a particular penetration level (as opposed to the average economic value of all variable renewables up to that penetration level). Transmission constraints, on the other hand, are not considered in this analysis, nor many other costs and impacts that may be important. The costs and impacts that are not considered in this analysis include monetary estimates of 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. The analysis also does not consider the capital cost of variable renewable generation, instead focusing on the economic value of that generation and how it changes with increasing penetration: a full comparison among generation technologies would, of course, also account for their relative cost.

Notwithstanding these caveats, understanding the economic value of variable generation—even as narrowly defined here—is an important element in making long-term decisions about renewable procurement and supporting infrastructure.

Approach

This report uses a long-run economic framework to evaluate the economic value of variable generation that 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 on-going fixed O&M costs). Variable renewable generation (VG) is added to the power system at various penetration levels and a new long-run equilibrium is found in the rest of the system for that given penetration of VG. The new investment options include natural gas combined cycle (CCGTs) and combustion turbine plants (CTs), as well as coal, nuclear, and pumped hydro storage (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 cost of that generation.

A unique aspect of the long-run model used in this report is that it incorporates significant detail important to power system operations and dispatch with variable generation, including hourly generation and load profiles, unpredictability of variable generation, ancillary service requirements, and some of the important limitations of conventional thermal generators including part-load inefficiencies, minimum generation limits, ramp-rate limits, and start-up costs. As is explained in the main report, the operational detail is simplified through committing and dispatching vintages of generation as a fleet rather than dispatching individual generation plants. The investment decisions are similarly simplified by assuming that investments can occur in continuous amounts rather than discrete individual generation plants.

Case Study

This long-run model is applied to a case study that loosely matches characteristics of California in terms of generation profiles for variable generation, existing generation capacity, and the hourly load profile in 2030. 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 pumped hydro storage. Fossil-fuel prices are based on the fuel prices in 2030 in the EIA's Annual Energy Outlook 2011 reference case forecast.

In each of the scenarios considered in this analysis, one VG technology is increased from a base case with essentially no VG (the 0% case) to increasingly high penetration levels measured on an energy basis. The amount of VG included in each case is defined by the scenario and is not a result of an economic optimization. The scenarios are set up in this way to observe how the marginal economic value of VG changes with increasing penetration across a wide range of penetration levels.

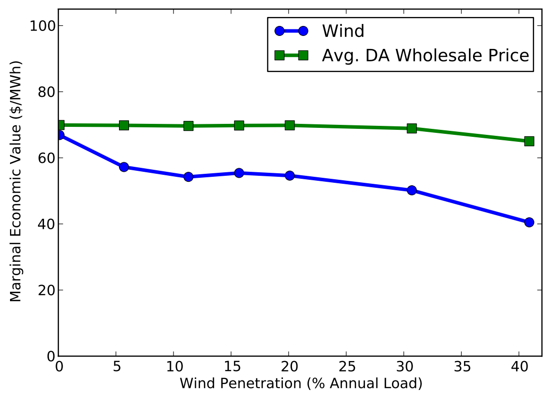
Aside from the reference scenario, four sensitivity scenarios are evaluated to show the relative importance of: major fossil plant operational constraints; monetary valuation of the cost of emitting carbon dioxide; reductions in the cost of resources that provide capacity (i.e., combustion turbines); and assumptions about the retirement of existing thermal generation.

Results and Conclusions

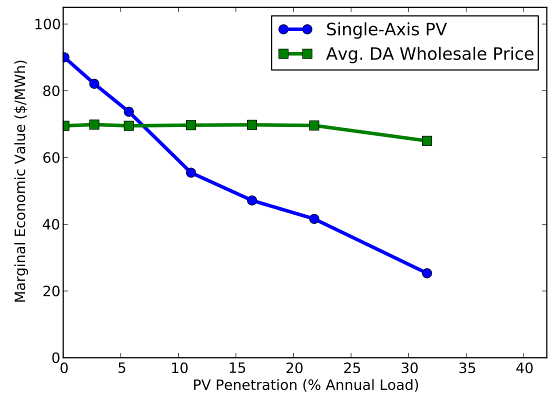
Application of the framework to a case study of California results in investments in new CCGTs in addition to the incumbent generation and, at least in the reference scenario, no retirement of incumbent generation for economic reasons (generation that is older than its technical life is automatically assumed to retire and is not included in the incumbent generation). Since the system is always assumed to be in long-run equilibrium, the wholesale power prices in the market are such that the short-run profit of the new CCGTs is always sufficient to cover its fixed cost of investment at any VG penetration level. One impact of adding VG is to reduce the amount of new CCGTs that need to be built, though the amount avoided varies across VG technologies and VG penetration levels. New CTs are not built in the reference scenario. Modestly lowering CT capital costs in a sensitivity case results in a combination of CTs and CCGTs being built. The relative proportion of new generation shifts more toward CTs with increasing penetration of wind, PV, and CSP_0 in the sensitivity case. The assumed costs of new coal, nuclear, and pumped hydro storage are too high to result in investments in these technologies at any of the considered levels of VG penetration.

Additions of VG primarily displace energy from natural gas fired CCGTs. Though pollution emisssions are not a focus of this analysis, emissions are a byproduct of the investment and dispatch decisions. Increasing penetration of variable generation results in decreased CO_2, NO_x, and SO_2, even after accounting for part-loading and emissions during start-up for thermal generation. The rate of emissions reduction varies with penetration level and variable generation technology.

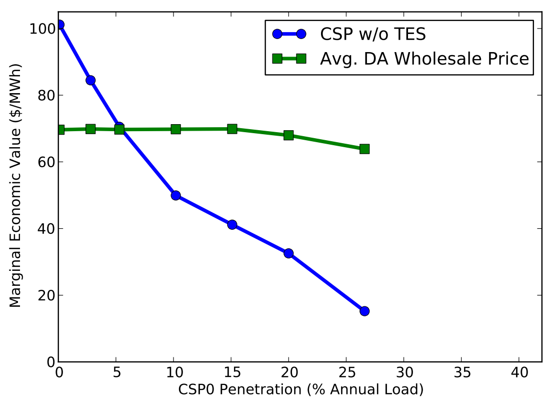
The case study also shows that the marginal economic value of VG differs substantially among VG technologies and changes with increasing penetration. The resulting marginal economic value of wind, PV, CSP_0, and CSP_6 with increasing penetration of each VG technology is shown in Figure ES.1. For comparison, also shown in the figure is the time-weighted average day-ahead wholesale power price at each penetration level.



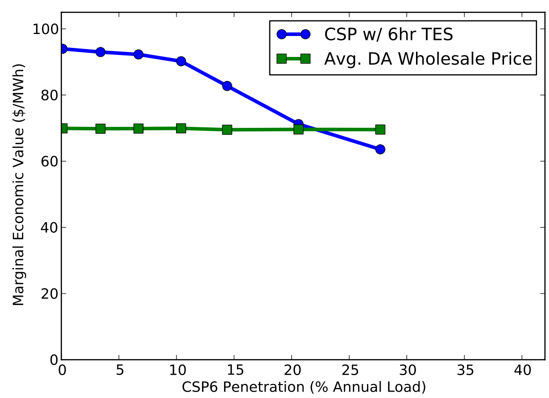
(a) Wind



(b) PV



(c) CSP_0



(d) CSP_6

Note: Economic value in \$/MWh is calculated using the total renewable energy that could be generated (energy sold plus energy curtailed).

Figure ES.1: Marginal economic value of variable generation and an annual flat-block of power with increasing penetration of variable generation in 2030.

The marginal economic value is calculated as the estimated short-run profit earned by VG from selling power into a day-ahead and real-time power market that is in long-run equilibrium for the given VG penetration. Because the system is in long-run equilibrium, the hourly market prices account for both the cost of energy and capacity, similar to the few "energy-only" power markets in the U.S. and elsewhere. The total revenue is calculated as the sum of the revenue earned by selling forecasted generation into the day-ahead (DA) market at the DA price and the revenue earned by selling any deviations from the DA forecast in the real-time (RT) market at the RT price. Variable generation is allowed to sell ancillary services (AS). In the case of PV, CSP_0, and wind only regulation down can be provided by the variable generators. Provision of regulation down by the variable generators only has a noticeable impact at high penetration levels. Even at high penetration levels sales of regulation down change the value of variable generation by less than \$2/MWh. These generators are further charged for any assumed increase in the hourly AS requirements due to increased short-term variability and uncertainty from VG. At all penetration levels, PV, CSP_0, and wind pay more for the additional AS requirements relative to revenue earned from selling regulation down.

In order to understand what drives the changes in marginal economic value with increasing penetration, the economic value is decomposed into four separate components: capacity value, energy value, day-ahead forecast error, and ancillary services. The resulting decomposition of the marginal economic value of each VG technology and the same decomposition for increasing penetration of a flat block of power is shown in Table ES.1. The components of the marginal economic value of VG with increasing penetration are shown in $/MWh terms, where the denominator is based on the energy that could be generated by the VG (the sum of the total energy sold and the total energy curtailed). The capacity value is also shown in $/kW-yr terms to illustrate the annual capacity value per unit of nameplate capacity.

- Capacity Value ($/MWh): The portion of short-run profit earned during hours with scarcity prices (defined to be greater than or equal to $500/MWh).
- Energy Value ($/MWh): The portion of short-run profit earned in hours without scarcity prices, assuming the DA forecast 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 VG and paying for increased AS due to increased short-term variability and uncertainty from VG.

The first key conclusion from this analysis is that the marginal economic value of all three solar options considered here is high, higher than the marginal economic value of a flat block of power, in California at low levels of solar penetration. This high value at low penetration is largely due to the ability of solar resources to reduce the amount of new non-renewable capacity that is built, leading to a high capacity value. The magnitude of the capacity value of solar resources depends on the coincidence of solar generation with times of high system need, the cost of generation resources that would otherwise be built, and decisions regarding the retirement of older, less efficient conventional generation.

Since the value of CSP at low solar penetration levels in California is found to be high with or without thermal energy storage, we find that there is little apparent incremental value to thermal storage at low solar penetration when the power system is in long-run equilibrium. Thermal energy storage may be justified for other reasons, but there is no clear evidence in the present case study analysis that it is required in order to maximize economic value at low solar penetration.

Without any mitigation strategies to stem the decline in the value of solar, however, the marginal economic value of PV and CSP_0 are found to drop considerably with increasing solar penetration. For penetrations of 0% to 10% the primary driver of the decline is the decrease in capacity value with increasing solar generation: additional PV and CSP_0 are less effective at avoiding new non-renewable generation capacity at high penetration than at low penetration. For penetrations of 10% and higher the primary driver of the decline is the decrease in the energy value: at these higher penetration levels, additional PV and CSP_0 start to displace generation with lower variable costs. At 20% solar penetration and above, there are increasingly hours where the price for power drops to very low levels, reducing the economic incentive for adding additional PV or CSP_0. Eventually a portion of the energy generated by those solar technologies is curtailed. This decline in the marginal economic value of PV and CSP without thermal storage is not driven by the cost of increasing AS requirements and is not strongly linked to changes in the cost of DA forecast errors.

The marginal economic value of CSP_6 also decreases at higher penetration levels, but not to the extent that the value of PV and CSP_0 decline. As a result, at higher penetration levels the value of CSP with thermal storage is found to be considerably greater than the value of PV or CSP_0 at the same high penetration level. The capacity value of CSP_6 remains high up to penetration levels of 15% and beyond because the thermal energy storage is able to reduce the peak net load even at higher penetration levels.

The marginal economic value of wind is found to be significantly lower than solar at low penetration due to the lack of correlation or slightly negative correlation between wind and demand. This lower value of wind is largely due to the lower capacity value of wind. The decline in the total marginal economic value of wind with increasing penetration is found to be, at least for low to medium penetrations of wind, largely a result of further reductions in capacity value. The energy value of wind is found to be roughly similar to the energy value of a flat block of power (and similar to the fuel and variable O&M cost of natural gas CCGT

Table ES.1: Decomposition of the marginal economic value of variable generation in 2030 with increasing penetration.

Component	Penetration of a Flat Block						
($/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(170) 20	(180) 20	(170) 20	(180) 20	(180) 20	(180) 20	(140) 16
Energy Value	50	50	50	50	50	50	49
DA Forecast Error	0	0	0	0	0	0	0
Ancillary Services	0	0	0	0	0	0	0
Marginal Economic Value	70	70	70	70	70	70	65

Component	Penetration of Wind						
($/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(69) 17	(37) 12	(30) 10	(30) 10	(28) 9	(25) 8	(25) 8
Energy Value	50	49	48	48	48	46	39
DA Forecast Error	-0.2	-3	-4	-2	-2	-3	-6
Ancillary Services	-0.4	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Marginal Economic Value	67	57	54	55	54	50	40

Component	Penetration of PV						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(120) 37	(110) 34	(82) 27	(39) 13	(24) 8	(11) 4	(4) 1
Energy Value	54	53	52	49	45	41	27
DA Forecast Error	-0.2	-5	-4	-6	-5	-4	-3
Ancillary Services	-0.9	-0.8	-0.7	-0.4	-0.2	-0.1	-0.0
Marginal Economic Value	89	81	73	55	47	41	25

Component	Penetration of CSP_0						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(110) 47	(84) 36	(54) 24	(22) 10	(11) 5	(6) 3	(5) 2
Energy Value	56	54	52	46	41	33	16
DA Forecast Error	-2	-5	-5	-6	-5	-4	-4
Ancillary Services	-1.1	-0.8	-0.5	-0.2	-0.1	-0.1	-0.1
Marginal Economic Value	100	84	70	50	41	32	14

Component	Penetration of CSP_6						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(150) 37	(160) 37	(150) 37	(150) 35	(100) 24	(85) 20	(61) 15
Energy Value	55	55	55	55	58	53	52
DA Forecast Error	-0.1	-1	-1	-1	-1	-2	-3
Ancillary Services	1.4	1.4	1.3	1.2	1.0	0.7	0.1
Marginal Economic Value	94	93	92	90	83	71	64

a - Capacity value in parentheses is reported in $/kW-yr terms and reported to two significant digits.

resources operating at full load). Only at very high penetration levels does the energy value of wind start to drop in the California case study presented here. The DA forecast error costs have little influence on the value of wind at low penetration and remain fairly manageable, on average less than \$7/MWh, even at high penetration levels. AS costs are not found to have a large impact on the economic value of wind as modeled in this analysis.

At high penetration levels, the marginal economic value of wind is found to exceed the value of PV and CSP without thermal storage. While the marginal economic value of solar exceeds the value of wind at low penetration, at around 10% penetration the capacity value of PV and CSP_0 is found to be substantially reduced leading to the total marginal economic value of PV and CSP_0 being similar to the value of wind. At still higher penetrations, wind is found to have a higher marginal economic value than PV and CSP_0. This is due to the energy value of PV and CSP_0 falling faster than the energy value of wind while the capacity value of wind remains slightly higher than the capacity value of PV and CSP_0 at high penetration levels. As is explained in Section 5, the decline in the capacity value of PV and CSP_0 at high penetration is largely due to the time with high net load and high wholesale power prices shifting from the late afternoon, when solar production is high, to early evening hours when the sun is setting. The decline in the energy value is due to a combination of increased part-loading of CCGTs, increased displacement of the small amount of incumbent coal generation, and increased curtailment of PV and CSP_0. These factors all impact the energy value of wind in a similar way, though the impacts occur at relatively higher wind penetration levels. CSP_6, on the other hand, is found to have a considerably higher value than wind at all penetration levels.

Though some of these results may be somewhat unique to the specific case study presented here, and the model only captures a subset of the benefits and costs of renewable energy, the findings provide unique insight into how the value of that subset changes with technology and penetration level. Moreover, the magnitude of these variations in value across technologies and at different penetration levels suggest that resource planners, policy makers, and investors should carefully consider the economic value and relative differences in the economic value among renewable energy technologies when conducting broader analyses of the costs and benefits of renewable energy. The findings also show the importance of an analysis framework that addresses long-term investment decisions as well as short-term dispatch and operational constraints, and point to areas where future research is warranted. For example, though this study focused on California and just one variable generation technology at a time, the same framework can be used to understand the economic value of variable generation in other regions and with different combinations of renewable energy. In a future report, the same framework will be used to evaluate how changes in the power system, like price responsive demand, more flexible thermal generation, and lower cost bulk power storage, might impact the value of variable generation. Each of these "mitigation strategies" might help slow the decline in the marginal economic value of variable generation found in this report.

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Acronyms

AS	Ancillary services
CAISO	California Independent System Operator
CCGT	Combined cycle gas turbine
CEMS	Continuous Emissions Monitoring System
CSP	Concentrating solar power
CT	Combustion turbine
DA	Day ahead
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EUE	Expected Unserved Energy
LCOE	Levelized cost of energy
LOLP	Loss of load probability
LOLE	Loss of load expectation
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
O&M	Operations and maintence
PHS	Pumped hydro storage
PPA	Power purchase agreement
PTC	Production tax credit
PV	Photovoltaic
REC	Renewable energy credit
RPS	Renewables portfolio standard
RT	Real time
SAM	System Advisor Model
T&D	Transmission and distribution
TES	Thermal energy storage
WECC	Western Electricity Coordinating Council
WREZ	Western Renewable Energy Zone Initiative
WWSIS	Western Wind and Solar Integration Study
VG	Variable generation
VOLL	Value of lost load

1 Introduction

Long term decisions regarding how much renewable energy to procure, what type of renewable energy to procure, and what supporting infrastructure to build are made difficult by the variable and unpredictable nature of some renewable resources, in particular wind and solar. In order for decisions to be made on an economic basis, the costs of procuring variable renewables needs to be compared to the benefits of those renewables. The costs side of the equation considers metrics like the levelized cost of energy (LCOE) or the cost of a power purchase agreement (PPA) (Wiser and Bolinger, 2011; Barbose et al., 2011; Fischedick et al., 2011). The costs can also include the contribution of renewables in expanding the need for infrastructure, like the bulk transmission network, to deliver renewables supply to electric loads (Holttinen et al., 2011; Mills et al., 2011, 2012). The benefits side, also called the "avoided costs", can include a wide range of factors including hedging against fossil fuel price fluctuation, reducing environmental impacts from other sources of electricity, and avoiding fuel, operations and capital cost expenditures from operating other power plants (Angeliki, 2008). Renewable resources that are sited on the distribution system near electric loads have further potential benefits of reducing electrical losses and avoiding expenditures related to transmission and distribution (T&D) system infrastructure. The potential benefits depend on a wide range of factors including penetration level, generation profile, and network characteristics (Passey et al., 2011; Cossent et al., 2011).

This report only focuses on quantifying the benefits side of this equation and it further only focuses on a subset of the benefits. The objective of the research is to quantitatively examine the marginal economic benefits of additional variable renewables in avoiding the capital investment cost and variable fuel and operations and maintenance (O&M) costs from other power plants in a power system while including operational constraints on conventional generators and the increased need for ancillary services from additional variable renewables. This subset of the benefits of renewables will be referred to as the "marginal economic value" in this paper, though it is recognized that this narrow definition of marginal economic value focuses only on certain direct cost savings of renewable energy in wholesale electricity markets and does not include many other impacts that renewable energy sellers, purchasers, and policymakers might and do consider. The analysis does not include impacts to the transmission and distribution system so the potential benefits or costs of distributed generation are excluded from this report. This report also does not consider externalities, public benefits, or renewable energy costs in evaluating the narrowly defined economic value.

The primary focus of this research is in determining how the economic value of variable renewables changes with increasing penetration levels. The economic value with increasing penetration levels is compared between four renewable technologies: wind, single-axis tracking photovoltaics (PV),[1] concentrating solar power (CSP) without thermal storage (CSP_0), and CSP with 6 hours of thermal storage (CSP_6).[2] The purpose of comparing four different technologies at many different penetration levels is to highlight the drivers of changes and differences in the value of variable renewables along with areas where further research is warranted. In addition to examining the changes in the value of variable renewables with increasing penetration, a case where the penetration of a flat block of power that delivers electricity on a 24×7 basis is increased in a manner similar to the variable generation cases for comparison purposes.

This report loosely uses California as a case study to explore these impacts, and relies on an investment and dispatch model that simultaneously considers long-run investment decisions and short-run operational constraints using hourly data over a full year. The dispatch model does not include transmission constraints

[1]Deployment of PV is currently a mix of fixed PV with various orientations, single-axis tracking PV, dual axis tracking PV, and concentrating PV. This report only evaluates single-axis tracking PV tilted at an angle equivalent to the latitude of the PV site. Though the exact numerical results will likely differ across the different PV technologies or combinations of PV technologies, analysis of the value of PV at low penetration demonstrates that the value of PV differs by less than $10/MWh between fixed PV tilted at the latitude and oriented toward the south and tracking PV. Between single-axis tracking at zero tilt, single-axis tracking at latitude tilt, and dual axis tracking the differences in the marginal economic value at low penetration are less than $3/MWh.

[2]This report does not consider the potential for natural gas firing in the steam generator of a CSP plant nor does it consider hybrid solar-conventional plants where steam from the solar field is injected into the feedwater system of a conventional thermal plant (e.g. the steam cycle of a CCGT or a coal plant). Furthermore, thermal storage for CSP, which is dispatched based on system needs within the dispatch model, is limited to 6 hours in the majority of the scenarios except one test of the economic value of CSP with 10 hours of thermal storage at 20% penetration. These potential mitigation options for CSP could be considered in future research.

nor does it consider the potential for generation outside of the case study area (California in this report) to be displaced or to provide flexibility in managing increased variable generation. Variable generation that is sited outside of California, however, is assumed to be able to be dynamically scheduled into California, such that all of the variability and uncertainty is managed within California. The model was designed to quickly evaluate the economic value of variable renewable resources over a wide range of penetration levels and a variety of sensitivity scenarios.

Absent from this analysis is an evaluation of several strategies that might be available to reduce any decline in economic value of variable renewables with increasing penetration. These strategies, including technology diversity (i.e., combinations of VG technologies), more flexible thermal generation, price responsive demand through real-time pricing programs, and low cost bulk power storage, may increase in value with increasing penetration of variable renewables and in turn, may increase the economic value of variable renewables at higher penetration levels. A future report will use the same framework presented here to evaluate the impact of these strategies in more detail. In addition, assumptions regarding the interaction of California with generation and loads in the rest of the Western Electricity Coordinating Council (WECC) could be examined in the future since excluding the rest of WECC from this analysis is potentially an important assumption.[3]

The remainder of this report begins by reviewing the existing literature regarding the economic value of variable renewables and changes in that value with increasing penetration levels. The review focuses on describing the importance of the long-run economic value of variable energy generation while also considering operational constraints in conventional power systems. The following section outlines the methodology used in this report to evaluate the economic value of variable generation (VG) with increasing penetration levels, including a description of how investment decisions in non-VG resources are made in the model, how those resources are dispatched, and how long-run wholesale electricity prices are calculated. The methodology section also explains the implied capacity credit of variable generation and how the economic value of variable generation is decomposed into several different components. The data and assumptions section provides further detail on the quantitative input values used in the case study presented in this report of increasing penetration of variable generation for 2030 in California. The results section then summarizes the long-run dispatch and investment results for different penetration levels of variable generation to help understand the long-run economic value of variable generation. The long-run value of wind, PV, and CSP with and without thermal storage are then compared with increasing penetration and that value is then decomposed into several constituent parts. Sensitivity cases that include relaxing thermal and hydro operational constraints, adding a carbon tax, reducing the cost of resources that primarily provide capacity (i.e., combustion turbine peaker plants), and assuming that no thermal plants retire for technical life reasons by 2030 are then used to better understand the factors that impact the economic value of variable generation. Key findings from the results are then summarized in the final concluding section. The appendices provide an overview and detailed description of the model developed for and used in this report, numeric values for parameters used to characterize thermal and hydro generation, and additional results from the sensitivity scenarios.

[3] Regarding the marginal economic value of variable generation the assumption that the rest of WECC is ignored may understate the value at high penetration levels for the following reasons:

- If the rest of WECC has low VG penetration then the effective penetration considering all of WECC will be lower than the effective penetration considering only California.
- The rest of WECC has additional incumbent sources of flexibility including large hydro resources and additional pumped hydro storage that are not included. Furthermore additional thermal generation may be able to help manage variability and uncertainty so that California generators do not need to provide as much flexibility.
- Some loads in the rest of WECC have peak periods that correspond with heating loads in the winter evening which may increase the capacity value of wind.

This assumption may also overstate the value at high penetration levels for the following reasons:

- WECC has additional generation with low variable costs or limited flexibility, including incumbent coal and nuclear generation. Expanding the analysis footprint to all of WECC would increase the overall proportion of these resources thereby decreasing the energy value and increasing the curtailment of variable generation.

Without more detailed analysis it is not possible to say with certainty which of these factors would have the biggest impact on the marginal value of variable generation at high penetration levels.

2 Background

Before describing the methodology used to evaluate the economic value of variable generation with increasing penetration levels in Section 3, this section first provides motivation for the detailed focus on the economic value of variable renewables, outlines approaches for estimating long-run economic value, and identifies previous studies of the economic value of variable renewables. The majority of the existing literature that covers the economic value of variable generation focuses on wind, though more recent studies have begun to evaluate the economic value of solar. This section again only focuses on literature that covers the limited definition of economic value used in this report, which covers direct investment costs, fuel costs, O&M costs for conventional generators and excludes investment costs for variable generators, T&D impacts, and other public benefits. This narrow focus does not provide a full cost/benefit analysis of variable generation, but it does allow clear exploration of a subset of the issues that would drive a full cost/benefit analysis.

2.1 Role of Economic Value in Renewable Procurement Decisions

The need to better understand the economic value of variable renewables was recently highlighted by Joskow (2011) and Borenstein (2012). Joskow argues that it is inappropriate to make economic comparisons of variable generation resources based only on life cycle costs or LCOE metrics. The reason that comparisons based on LCOE alone are inappropriate is that the economic value of a unit of energy depends on the time when the energy is generated, or more specifically, the conditions of the power market during that time. The value of energy, as captured by wholesale power market prices, can vary by orders of magnitude depending on whether the power system has ample low cost generation available or little generation of any sort available. Energy that is generated during times when prices are high is much more valuable than energy generated during times when prices are low. Economic comparisons between different generating technologies need to therefore account for how well correlated generation is with these times. Since LCOE comparisons do not account for differences in value depending on when energy is generated, these comparisons do not reflect differences in the value of a resource to a power system.

An alternative to comparing resources simply based on LCOE metrics or PPA prices is to compare them based on their relative total net benefits. The total net benefit in this case might be estimated by subtracting the total costs of a resource from the total revenues it would earn by selling its power into a wholesale power market with time varying prices. This is also called the "market test" by Borenstein (2012). Analogously, this test can be restated as: does the short-run profit of a resource exceed its fixed costs of investment and operations, where the short-run profit is the difference between the total revenues earned if power were sold at prevailing wholesale market prices and the generator's variable costs (i.e., fuel, wear & tear, and O&M).[4] As noted by Borenstein, there is active debate regarding the extent to which variable renewables impose costs that cannot be reflected in energy market prices because the costs are due to actions that power system operators take outside of the normal market timelines. In particular, system operators may need to add additional operating reserves or some other form of non-energy market product (e.g. a "ramping product") to accommodate variability and uncertainty that is not resolved within the timelines of the power market (e.g., reserves to manage sub-hourly variability and uncertainty in a market where the shortest scheduling interval is hourly). In this case, the market test can be modified by further subtracting any estimated share of additional costs due to the variable generators from the short-run profit.

This comparison can be carried out for any potential generation investment. Those resources whose short-run profits exceed fixed costs are the resources that are economic, not considering the other factors that might impact decisions mentioned earlier. Those resources whose short-run profits fall short of fixed costs require additional sources of revenue or a reduction in costs in order to also be economic. The required

[4]Often individual renewable energy plants sell their output directly to a load serving entity through a long-term contract based on a fixed price per unit of energy. In this case, the net benefit can be calculated from the perspective of the purchaser where the total cost is represented by the price paid for the power (the PPA price) and benefits are the time-varying avoided costs from not needing to buy the same amount of power from the wholesale power market at that time. In this fashion the perspective shifts from the resource owner to the resource purchaser, but the net benefits of the resource remain quantitatively similar.

increase in revenue or decrease in costs depends on the size of the gap between the short-run profit and the fixed costs. The idea of "grid parity" for any resource could similarly be interpreted as the point where the fixed cost of the resource equals the short-run profit of that resource in a power market.

Previous analysis of the sensitivity of renewable resource procurement decisions and transmission expansion in the Western Interconnection (Mills et al., 2011) used a similar framework to the approach advocated by Joskow and Borenstein. The analysis used a simplified framework where different renewable resource options were compared based on the delivered cost of the renewables net the market value of these renewables to load zones throughout the western United States. The analysis found that resource procurement and transmission expansion decisions in the Southwest were sensitive to factors affecting the cost of generating renewable energy (the bus-bar costs), the costs of delivering renewable resources to loads (the transmission costs), and the economic value of the renewables to loads (the market value). Depending on the scenario, resources would shift between wind and solar and transmission needs would similarly shift between high quality solar resource regions in the Southwest and various high quality wind resource locations throughout the West. The base solar technology assessed in the previous analysis was CSP_6; PV and CSP_0 were included in sensitivity cases. For a 33% renewable energy target, the solar penetration, in terms of the total amount of energy generated by solar as a percentage of the annual demand,[5] was found to vary between 4–13% and the wind penetration was found to vary between 12–21% depending on the scenario.

One of the simplifying assumptions in the screening tools used in that study was that the economic value of the renewables did not change with penetration level. Part of the motivation of the present report was to develop a better understanding of how the economic value of variable renewables changes at increasing penetration levels. To develop this understanding a much more detailed investment and dispatch model was required to evaluate the economic value component with increasing penetration levels. As will be explained, one of the main findings of this analysis is that the marginal economic value of variable renewables does change between low penetration and high penetration, particularly for PV and CSP_0.

Projections of high future penetration levels of variable renewables are common. Contributing to these projections in the U.S. are the 29 states in the U.S. with renewable energy standards, including California which is set at 33% renewables by 2020 (Wiser and Bolinger, 2011). In addition, the U.S. Congress has in the past considered further supporting clean energy with federal standards. The European Union set an overall binding share of gross final energy consumption of 20% renewables by 2020 (IEA, 2010). As a result of this binding target, renewable electricity is expected to provide 37% of Europe's electrcity in 2020 with wind and solar both making substantial contributions (European Commission, 2011). Combined with interest in variable renewables in other countries and operating experience in countries with high penetration of wind energy, it is clear that there is strong interest in understanding the impacts of high penetration of renewable energy.

There is also interest in high penetration of variable renewables in studies that focus on mitigating climate change. In one assessment of 162 different climate mitigation and future energy scenarios, the percentage of electricity from wind energy in aggressive mitigation scenarios by 2030 was around 10% in the median scenario with the 75^{th} percentile approaching 25% wind penetration. The percentage of electricity from PV in the aggressive mitigation scenarios by 2030 reached only around 1% in the median scenario and 7% in the 75^{th} percentile scenario though with more-sizable growth after 2030 (Krey and Clarke, 2011). Given the range of variable renewable penetration levels that are being considered in these and other studies, as well as the high levels of VG already experienced in some regions and to increasingly be expected in other regions it is important to understand how the economic value of variable renewables might change over a wide range of penetration levels.

2.2 Modeling the Long-Run Impact of Variable Renewables at Varying Penetration Levels

One of the challenges of using wholesale power market prices to evaluate the economic value of variable generation (to then compare to the fixed cost or PPA price of those technologies) is that wholesale prices

[5] All penetration levels in this report similarly refer to penetration on an energy basis.

will change over the lifetime of a power plant. The current prices in this year or the prices in previous years may not reflect trends that can affect future prices like fuel changes, increased emissions controls or other environmental restrictions, and changes in the capital costs of new power plants. More importantly for the focus of this report, wholesale power prices change with increasing penetration of variable generation (Jacobsen and Zvingilaite, 2010; Woo et al., 2011; Podewils, 2011).[6] The recommendation that wholesale power market prices be used to estimate the economic value of variable generation from Joskow and Borenstein therefore requires the use of models to estimate future wholesale prices, particularly in the case of evaluating the economic value of variable generation with increased penetration levels.

There are several options available for creating models of future wholesale prices with increasing penetration of variable generation. As one approach, a number of studies have estimated the impact of variable renewables on power system operations by simply adding increased variable generation to a static mix of other generation capacity. In particular, a significant body of literature specifically evaluates the flexibility of the conventional generation system and the technical feasibility of integrating wind energy into existing power systems (Klobasa and Obersteiner, 2006; Smith et al., 2007; Strbac et al., 2007; Gross et al., 2007; Ummels et al., 2007; Gransson and Johnsson, 2009; Maddaloni et al., 2009; Wiser and Bolinger, 2011; Holttinen et al., 2011). The focus of this literature has primarily been based on the operations of the power system with increased wind and has therefore generally assumed that existing conventional generation is dispatched differently but that the installed capacity of that generation does not change with increased wind. The prices generated by models used in this literature therefore reflect only the short-run economic value of wind and not the long-run economic value of wind.

A short-run analysis, as used in these studies, is useful for a conservative assessment of operational integration issues, such as evaluating the technical feasibility of managing variable generation. A short-run analysis may be particularly useful for analyzing low levels of wind or solar penetration since low levels of penetration would not significantly affect wholesale power market prices or the mix of generation resources.

Scenarios of high wind and solar penetration over a period long enough to make investments in (or retirements of) other generating technologies, however, are better dealt with using a long-run analysis that can allow for changes in the generation mix due to new investments and plant retirements. In addition, answering questions about the impact of VG on investment incentives for conventional generation, investment incentives for measures to better manage wind or solar energy variability and uncertainty like storage, or impacts on consumer electricity prices all require understanding long-run dynamics. Some previous analyses of these latter questions have instead used a short-run framework where wind penetration is changed significantly and all other investments in the power system are kept the same irrespective of the wind penetration level (Hirst and Hild, 2004; Olsina et al., 2007; Sensfuß et al., 2008; Sioshansi and Short, 2009; Green and Vasilakos, 2010; Sioshansi, 2011; Traber and Kemfert, 2011): as a result, the conclusions from these studies only reflect short-run impacts and do not address important questions about the long-term impact of variable generation.

In the long run, generation can retire for technical or economic reasons, load can grow necessitating increased generation capacity, or new investments can be made based on the expected economic attractiveness of building new generation. The nature of some of these changes can be impacted by the amount of VG penetration. These long-run changes are therefore relevant for modeling future prices and for understanding the value of variable generation over the lifetime of a power plant, especially at higher VG penetration levels.

As described in more detail later, the model used in this report for estimating the value of variable generation is based on a long-run modeling framework that addresses investment and retirement decisions while also accommodating important operating constraints for conventional generation, Text Box 1. A product of the long-run modeling framework are hourly prices for energy and ancillary services that reflect the long-run cost of meeting an additional unit of demand in any particular hour. These long-run hourly

[6]Jacobsen and Zvingilaite (2010) reports lower prices and higher volatility with increasing wind in Denmark, while Woo et al. (2011) reports the same for wind in ERCOT. Morthorst (2003) reports a relatively weak relationship between wholesale market prices and wind, but a stronger relationship between wind generation and prices in imbalance markets. Jónsson et al. (2010) shows that a stronger relationship exists between wholesale prices in the day-ahead market and day-ahead *predictions* of wind power rather than day-ahead prices and actual wind generation. Podewils (2011) reports that mid-day day-ahead prices in Germany are decreasing due to the addition of large amounts of photovoltaic generation.

prices in combination with generation profiles are used to estimate the economic impact of adding additional variable generation resources.

2.3 Existing Studies of the Economic Value of Variable Renewables

Beyond the studies focused on operational integration challenges and studies of the economic value of VG at high penetration that use a short-run analysis framework cited earlier, a number of studies have examined the economic value of variable generation using either current prices or long-run prices generated in a scenario with no or low amounts of variable generation. Borenstein (2008) used historic real-time prices and simulated long-run equilibrium prices to estimate the economic value of PV in California at zero penetration. He showed that the long-run value of PV can exceed the value estimated using only flat-rate retail tariffs by up to 30–50% if fixed-axis PV panels were oriented toward the southwest. Mills et al. (2011) estimated market value adjustment factors for a variety of renewable resources in the western U.S. and found that the per unit of energy market value of solar technologies, particularly CSP_6, generally exceeded the per unit of energy market value of generation resources that were assumed to have flat generation profiles (e.g., biomass). The market value of wind was found to be lower than the market value of biomass, depending on the combination of wind generation profile and load center where the wind generation was delivered. Sioshansi and Denholm (2010) used current wholesale power prices in the Southwestern U.S to evaluate the economic profitability of CSP with and without thermal energy storage over a wide range of thermal storage and solar field size combinations. Fripp and Wiser (2008) found relatively little correlation between historic wholesale prices and different wind generation profiles in the western U.S. At low penetration the wholesale value of wind power was found to be similar to or up to around 10% less than the value of a flat block of power, depending on the wind site.

A growing body of literature provides significant insights into the long-run economic value of variable generation considering long-term investment and retirement decisions with increasing penetration levels, though with varying levels of temporal and geographic resolution. The models used in these studies are not necessarily designed to just quantify the economic value of renewables with increasing penetration, but the economic value of these resources is implicitly estimated in these models. In the U.S., the National Energy Modeling System (NEMS) is used by the Energy Information Administration to create energy forecasts in the Annual Energy Outlook. NEMS includes wind and solar energy in the mix of potential resources in their long-run assessment of future energy markets. The temporal resolution of NEMS, however, allows for only nine time periods per year and the geographic resolution is limited to thirteen supply regions (EIA, 2010).

The contribution of CSP to energy supply was investigated by Zhang et al. (2010) in the GCAM integrated assessment model, a model used for assessing future climate change mitigation scenarios. The GCAM model only used ten time slices over the year. Even with this low time resolution, Zhang et al. (2010) found decreasing economic incentives to build additional CSP with increasing penetration, though higher penetration levels were still attractive with the addition of a few hours of thermal storage.

The Renewable Energy Deployment System (ReEDS) model developed by the National Renewable Energy Laboratory greatly increases the geographic resolution of load and renewable energy data, but still uses relatively low temporal resolution of 17 time-periods per year. Several additional statistical correction factors are included in ReEDS to address the relatively low temporal resolution.[7] The ReEDS model has been used to evaluate investments in scenarios with 20% wind energy (DOE, 2008) and 20% solar (Brinkman et al., 2011).[8]

Comparison of dispatch and investment results depending on the level of temporal resolution used in modeling high wind penetration scenarios indicates that temporal resolution can significantly impact estimates of the long-run economic value of wind (Nicolosi et al., 2010; Ludig et al., 2011). As a result, when practical computing constraints can be overcome, studies of the long-run economic value of VG are increasingly seeking higher levels of temporal resolution, up to hourly with a full year or more of wind, solar and

[7] `http://www.nrel.gov/analysis/reeds/`

[8] In addition to developing generation investment decisions using 17 time-periods per year using the ReEDS model, Brinkman et al. (2011) verify that the system built by ReEDS can be operated using an hourly production cost model. The results of the hourly production cost model, however, are not fed back into the build-out and design of the system in ReEDS.

Text Box 1. Framework for evaluating long-run equilibrium

When a power system is in equilibrium, meaning that there is no economic incentive for existing units to leave the market and no economic incentive for additional units to be built, and only small changes in the system are investigated, short-run prices and long-run prices are similar. Major changes to a system, such as the addition of large amounts of wind or solar energy, however, can lead to a significant divergence between short-run prices and long-run prices. The long life of variable generation assets (>20 years) leaves time for changes in the other generation resources (e.g., retirement and new investment) and makes long-run prices more relevant for understanding the overall economic value of variable generation.

Stoft (2002) presents a simple framework for understanding the long-run dynamic response to changes in power systems, Figure 1. The operation of generating resources in a power market impacts short-run profits (again, defined as the difference between the total revenues earned from selling power in the market and the variable costs from generating power). Potential new generators then determine whether they should enter a market based on the expectation of the short-run profits the generation could earn in the market. If the short-run profits are high enough to cover the fixed cost of investment in new capacity then new generation will enter the market and add to the resources that can be dispatched.

The positive and negative symbols in Figure 1 indicate whether each step reinforces or dampens the next step. High prices, for instance, lead to an increase in short-run profits (positive), which increases the incentives to invest in new generation (positive) and can increase the amount of resources available in the market (positive). An increase in the amount of resources in a market, however, will **decrease** the prices in that market (negative). Overall, this feedback loop tends to be stable, meaning that it will push investments and prices to an equilibrium point where there is no economic motivation for additional new investments and no generator would retire for economic reasons. It also indicates that long-run equilibrium prices depend in part on the capital cost of investment options. The long-run impact of adding variable generation or any other resource to a power market depends on the impact the resource has on market prices, the change in the short-run profits for generators, and the change in investments because of the addition of the resource. Additional details of the long-run modeling approach used in this report are provided in Section 3.

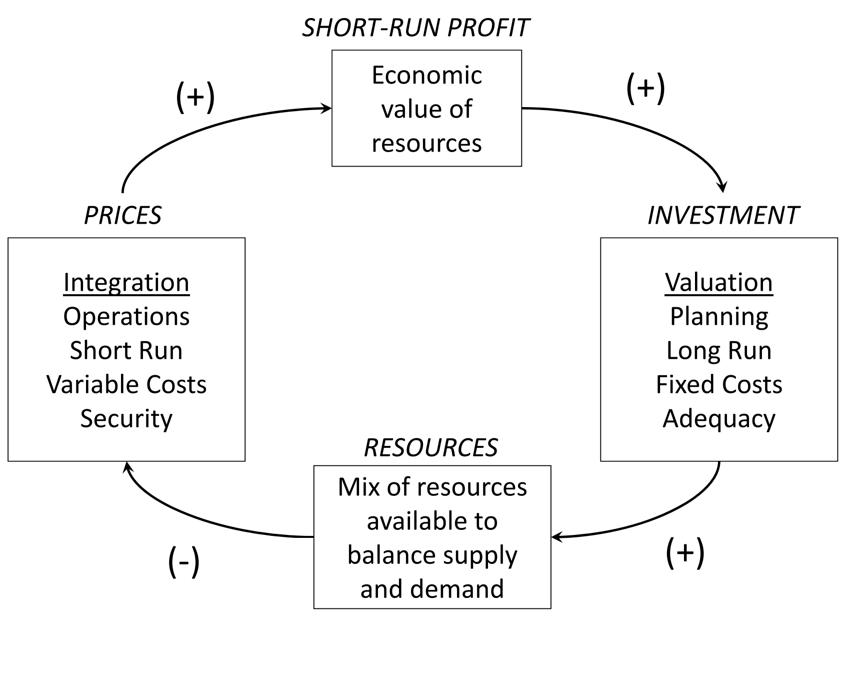


Figure 1: Framework for evaluating long-run economic value (adapted from Stoft (2002)).

load data. These studies often highlight the importance of geographic diversity, changes in the value of variable renewables between high and low penetration, changes in the long-run mix of conventional generation due to increased variable renewables, and the lower economic value for wind than an energy-equivalent flat block of power (Grubb, 1991; DeCarolis and Keith, 2006; Fripp, 2008; Lamont, 2008; de Miera et al., 2008; Bushnell, 2010).

Instead of focusing on the long-run value of wind, Swider and Weber (2007) use a long-run model with several "day types" (12 day types, each day with 12 time segments) to demonstrate the difference in total system costs when wind is variable and unpredictable compared to the costs if wind were to have a flat generation profile across the entire year. Somewhat unique amongst the studies that consider longer term impacts, their model includes more of the detailed operational constraints that impact the dispatch of thermal power plants. De Jonghe et al. (2011) compare the long- run investments that would be made in a power system with increasing penetration of wind energy using a method that includes several operational constraints for thermal generation to those investments that would be made if a more simple method that uses traditional screening curves without operational constraints were applied. Though they do not include uncertainty in wind generation in the analysis, they find that the inclusion of operational constraints in investment decisions leads to more baseload capacity being replaced by flexible mid-load generation in scenarios with significant wind.

Aside from these latter two studies, much of the existing literature on the economic value and operational integration of variable generation with increasing penetration tends to either (1) focus on longer term value but lack high temporal resolution and/or consideration of the operational constraints of conventional resources in the power system or (2) have high temporal resolution and pay significant attention to operational constraints but assume a static mix of conventional generation even at high penetration levels thereby focusing on short-run impacts and ignoring long-run dynamics.

3 Methodology

This report seeks to bridge the divide in the literature by incorporating hourly generation and load profiles, unpredictability of variable generation and some of the important limitations of conventional thermal generators including part-load inefficiencies, minimum generation limits, ramp-rate limits, and start-up costs. This detail is then used to calculate the long-run value of wind, PV, and CSP generation with increasing penetration levels considering long-run dynamics of retirements and new investment decisions. While the limitations of many of the earlier studies do not necessarily take away from the importance of their findings, including both operational constraints and hourly time resolution in a long-run analysis framework allows concerns about the uncertainty of variable generation and the limitations of thermal plant flexibility for managing variability and uncertainty to be more directly addressed in the estimations of the long-run economic value of variable generation.

The marginal economic value evaluated in this analysis is based on the avoided costs from conventional generators including avoided fuel costs, start-up costs, O&M costs, and capital investment costs for an additional increment of VG from a particular VG penetration level. In calculating the marginal economic value, factors such as the ability of variable generation to reduce investment in conventional generation capacity, the ability of VG to reduce consumption of different fuels at different times depending on current system conditions, the impact of day-ahead forecast errors from VG, and the need to increase ancillary services are all addressed to varying degrees. The new investment options in non-VG resources include CTs, CCGTs, coal, nuclear, and pumped hydro storage.

The analysis does not consider many other costs and impacts that may be important in some cases. The costs and impacts that are not considered in this analysis include 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. Similarly, the present analysis does not consider the investment cost in VG resources. These costs and factors are excluded in order to provide clarity in the drivers of the results of this analysis and to avoid the results being driven by specific local factors such as distribution system design or time lags in transmission investments. Of course, actual investment and policy decisions might reasonably consider these and other elements as well.

In each of the scenarios considered in this analysis, one VG technology is increased from a base case with almost no VG (the 0% case)[9] to increasingly high penetration levels measured on an energy basis. The amount of VG included in each case is defined by the scenario and is not a result of an economic optimization. In other words, the VG is "forced in" to the market without consideration of the investment or operating cost of the VG. The scenarios are set up in this way to observe how the marginal economic value of VG, as narrowly defined in this report, changes with increasing penetration across a wide range of penetration levels. The results provide a survey of the potential range of the marginal economic value of different VG technologies and how it changes with increasing penetration. As is described in Section 4.1, the generation profiles with increasing penetration to some degree capture the impact of geographic diversity by aggregating additional sites with unique generation profiles. No scaling of variable generation profiles was used to model higher penetration levels.

In this analysis the penetration of VG is increased for only one VG technology at a time. Combinations of VG technologies, like wind and PV or PV and CSP with thermal storage, are not considered here. Combinations of VG technologies will be addressed in a future paper as a form of "technological diversity" that might stem the decrease in the economic value of VG at high penetration when only one technology is deployed along with other strategies such as price responsive demand, more flexible thermal generation, and low-cost bulk-power storage.

The high penetration cases include solar penetration levels that approach 30% of electricity. In the case of wind energy it was decided to push the penetration even higher to just over 40% on an energy basis due to the relatively smaller change in the marginal economic value of wind between 10% and 30% penetration relative to solar, as will be described in the later sections.[10] There were no fundamental barriers that prevented further increases in the penetration level beyond the levels examined here, although, as is shown later, VG curtailment and decreased marginal economic value at high penetration reduce the incentives for increasing penetration to higher levels.

The marginal economic value derived from each of these cases can be interpreted as the maximum marginal investment and fixed O&M cost that a VG technology would need to have to justify additional investment beyond the amount of VG considered in the case. In a case where the marginal value of VG is, for instance, \$70/MWh at 10% penetration then the marginal investment and fixed O&M cost of the VG would need to be below \$70/MWh to economically justify investment in additional VG. This interpretation, of course, ignores the many factors that are excluded from this analysis that could change the absolute level of the marginal value. The relative changes from low penetration to high penetration and the comparisons across VG technologies are therefore the more relevant indicators of the drivers of the marginal economic value rather than the absolute magnitudes.

California is chosen for this particular case study as an example of the application of the model and framework used to estimate marginal economic value of VG with increasing penetration, though this study is not designed or intended to exactly mimic all of the laws, policies, and various other factors that impact the electricity market in California. That being said, California is chosen due to the recent aggressive Renewables Portfolio Standard (RPS) of 33% by 2020 that was signed into law[11] and the diversity of renewable resources that are actively being considered in renewable procurement in the state, including wind, PV, CSP with and without thermal energy storage (TES), and some geothermal and biomass. Decisions that renewable project developers, utilities, regulators, and system operators are making or will need to make in the near future somewhat depend on the relative cost and benefits of these different renewable resources. Of particular

[9] Every case includes at least 100 MW of wind, PV, and CSP in order to observe how the value of these technologies change when the value of the other VG is increased to high penetration levels.

[10] Note that the exact penetration level used to describe each of the cases varies from the case title. For example, the actual penetration of PV in the "30% PV" case is 31.5%. The reason for the discrepancy is differences between the amount of annual energy production across individual renewable energy project sites that are aggregated to create the overall VG generation profile relative to the estimated amount of energy that would be generated by a typical site. The number of sites used to generate the profiles for the different penetration levels was based on typical estimates of annual energy production rather than site specific estimates. As a result the number of sites used in the "30% PV" case slightly exceeded the number of sites that were needed to generate exactly 30% of the annual electricity in the study year.

[11] `http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf`

importance has been the recent rapid decline in the cost of photovoltaics (Barbose et al., 2011). In California this reduction in PV costs, among other factors, has led to a number of proposed renewable projects shifting from CSP technology (often based on solar trough or parabolic dish technology) to PV as well as the addition of thermal energy storage to some proposed CSP plants in order to boost their value to the power system. Wind resources located in and out of California will also continue to compete with these solar technologies in renewable procurement decisions. It is therefore important to quantitatively understand how the benefits, including the economic value, compare across technologies and change with increasing penetration. Similar questions regarding the relative economic value of renewable resources occur in many different regions, but the marginal economic value of VG with increasing penetration may vary to some degree depending on the characteristics of the conventional generation, VG resources, and electric loads.

The remainder of this section summarises the framework and model that is used to estimate the marginal economic value of VG with increasing penetration, considering both long-run retirement of and investment in non-VG generation resources as well as commitment and dispatch decisions that occur during operations while accounting for the constraints that limit dispatch of conventional plants. The section first describes how power plants are committed and dispatched in the model, and then describes how the decision to invest in new non-renewable power plants is made. The method used for calculating the capacity credit of the VG based on the change in total investments in new power plants is also described. The marginal economic value of VG can then be calculated based on the dispatch results (i.e., wholesale power and ancillary service prices) from the non-VG power plant investments that were previously found to lead to a market equilibrium in the year 2030. The model itself is formulated for the purpose of this analysis in the mathematical programming language called AMPL and is solved using the IBM ILOG CPLEX Optimizer. Additional details of the model can be found starting in Appendix A.

3.1 Dispatch

The commitment and dispatch portion of the model used in this analysis (called the dispatch model) determines schedules and dispatch for thermal generation, hydropower, pumped hydro storage, variable generation, and load using hourly data over a full year. The dispatch decisions are co-optimized with decisions regarding which resources will provide ancillary services to meet reserve targets in each hour. The ancillary service requirements include non-spinning, spinning, and regulation reserves which are differentiated primarily by whether or not a resource must be online in order to provide reserves and by the time by which the reserve must be able to be fully deployed. The thermal generation constraints and parameters include variable O&M costs, the cost of fuel consumed just to have the plant online (called the no-load cost), 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 the minimum generation limit for online generation. The source of the numerical values used for these parameters is discussed later in Section 4. Hydropower is limited based on a monthly hydropower generation budget and an hourly minimum generation limit. Pumped hydro storage is limited by the capacity of the storage converter and by the reservoir capacity. All variable generation is assumed to be able to provide regulation-down, but CSP_6 is the only VG technology that can provide regulation-up and spinning reserves. Transmission constraints are not included in the dispatch and commitment decisions.[12]

The dispatch model focuses on two primary time horizons, the day-ahead (DA) and real-time (RT). These two time horizons correspond to the market time-lines used in many of the organized markets in the United States, including the California Independent System Operator (CAISO).

In the DA process used in this model, forecasts of output from variable generation are used to determine schedules for all generation that will maximize social welfare (consumer surplus plus supplier surplus) based

[12]There is nothing inherent in this framework that requires transmission constraints to be excluded from the dispatch and commitment model. With a more detailed dispatch model transmission constraints could explicitly be modeled. In the long-run, however, transmission investments can also be made which would require including transmission investment options and decisions regarding where to site new generation investment. These decisions are possible to include in the investment model but would begin to rapidly increase the complexity of the model. For this pilot case study of California options relating to transmission were ignored.

on the characteristics, constraints, and operating costs of generators, the availability of hydro generation, electricity demand, and the DA forecast of VG. The DA market prices for energy and ancillary services (AS) in each hour are based on the shadow value or dual value of constraints that require generation and load to be in balance in each hour and ancillary service targets to be met, respectively. The shadow value of an ancillary service target constraint, for example, represents the marginal change in the social welfare that would occur if the ancillary service requirement were to change by a small amount in that hour. The DA schedules and market prices contribute to the total revenues earned by any generation resource, as shown later.

In the RT process used in this model, generators are dispatched to maximize social welfare given the actual amount of VG that occurs in RT (considering forecast errors that occur in the DA). For generators that are not classified as quick-start generation, the commitment decision from the DA process is binding in the RT, thus limiting the options for maintaining a balance in RT. The combined-cycle vintage (CCGT) modeled in this analysis, for instance, is assumed to not be able to start within the hour and therefore does not have quick-start ability. If in the DA process CCGT resources are required to be on-line to meet the DA schedule, then in RT the CCGT resources can only be dispatched between the maximum capacity of CCGT generation that is online and the minimum generation limits of the online CCGT resources, while also considering ramp-rate limits. The CCGT cannot change to off-line in RT. On the other hand, simple-cycle combustion turbines (CT) are assumed to have quick-start ability. Even if CT resources are provided with a DA schedule that would leave the CT generation off-line, the CT resources can still be used in RT to balance the system if changes in system conditions require additional generation capacity.

3.1.1 Commitment Approach

The details of the dispatch model can be found in Appendix C. Overall the dispatch model is similar to the model outlined by Sioshansi and Short (2009). A key simplification in the approach used in this analysis, however, is that individual conventional generation plants are grouped into vintages that have similar generation characteristics. Each vintage is then dispatched as a combined resource rather than directly committing and dispatching individual units.

Instead of committing individual units, the commitment process in this simplified dispatch model determines how much capacity within a vintage will be online in each hour of the next day (and the current day in the case of quick-start vintages). The decision to increase or decrease the amount of on-line generation considers that any increase in the amount of vintage that is on-line causes an increase in the total startup cost.[13] The commitment process also determines how much of the on-line fraction of the vintage will be used to generate energy or, alternatively, to provide reserves from spinning resources. The minimum generation and ramp-rate constraints and part-load impacts are then based on the amount of online generation in any hour.

Grouping plants into vintages results in a simplification that treats generators as a continuous resource (i.e. linear dispatch of capacity) rather than a discrete resource (i.e. stepwise dispatch of capacity). This simplification allows the problem to remain linear and therefore results in more reasonable solution times relative to a model that commits each unit individually (which would make the dispatch model a mixed-integer linear program rather than a linear program). Overall the impact of this simplification on the results is somewhat ambiguous: linear commitment and dispatch constraints would tend to overstate the flexibility of the system while aggregating all existing units and using average plant characteristics understates the flexibility of some units.

A similar vintage-based commitment and dispatch approach was used by Müsgens (2006) to model market power in Germany and by Müsgens and Neuhoff (2006) to model the dispatch of a power system with wind

[13]The simplification further only focuses on start-up costs and does not include a minimum run time constraint. The start-up costs are somewhat high which makes it unattractive to start generation if it is only going to be used for a short time. Furthermore, it would not make sense to apply the average minimum run time for individual units to the entire fleet of generation within the same vintage. It doesn't make sense because staggering individual unit start-up times can make the minimum time that a certain amount of the fleet is online much shorter than the individual run times for each unit that makes up the fleet.

generation. Additional details of this approach are available in Kuntz and Müsgens (2007). Advantages and disadvantages of the linear "ready-to-operate" approach used by Müsgens (2006) relative to integer unit-commitment models are quantitatively evaluated by Abrell et al. (2008).[14]

3.1.2 Storage and Hydro Resource Dispatch

Modeling resources with storage, including hydro, bulk power storage, and thermal storage for CSP resources, can add significant complexity due to uncertainty over time periods relevant to the scheduling and dispatch of the storage. Modeling hydro and storage resources in dispatch models is particularly challenging due to the opportunity cost associated with discharging energy from a resource that is not then availabe at a later time that might be more valueable. Several of the challenges with modeling hydro generation in studies with significant variable generation levels are discussed by Acker (2011).

In this analysis, the complexity is significantly reduced by assuming that the DA schedules for the storage and hydro resources are set based on the DA forecasts of VG and the RT schedules are adjusted with perfect foresight to respond to the actual VG generation and system needs in RT. Based on these assumptions the dispatch of the hydro and storage resources is then co-optimized with the dispatch of the thermal generation in each individual case. This approximation somewhat overstates the ability of storage and hydro resources to respond in RT to system needs that differ from the DA schedules, but not unduly so. Though there is clearly room for improvement, the overall approach used in this analysis does not differ significantly from the manner that hydro is modeled in previous variable generation integration studies. Additional details regarding the specific hydro and storage modeling assumptions for this study are described in Section 4.3.

As a check to ensure that these resources were not earning extremely high revenues, the revenue earned by hydro in the model was compared to the revenue that a hydro resource would earn for the same scenario using a hydro dispatch algorithm based only on the net load (without any consideration of forecast errors, other generation, or reserves) and a simple peak shaving algorithm. At 30% penetration of PV or CSP_0 or 40% penetration of wind, hydro dispatched using the simple peak shaving algorithm earned only 4-8% less than the revenues earned with the optimized hydro dispatch from the dispatch model.

3.1.3 Scarcity Prices

Scarcity pricing is used in this model to signal periods where it is difficult to maintain balance between supply and demand.[15] In most hours of the year the market price for energy is based on the marginal cost of the most expensive vintage that is on-line, but not bound by minimum or maximum generation limits or ramping limits. In some cases the price is set based on the opportunity cost for dispatching hydro or storage in that hour (and therefore not being able to dispatch the hydro or storage in later hours). In cases where there is insufficient available capacity from on-line generation or vintages that are quick-start, the prices can rise even higher and thereby signal scarcity in the available generation resources. When insufficient generation is available to meet demand and AS targets the prices in this model rise to predefined scarcity price levels that can be interpreted as the assumed loss of social welfare for missing AS targets and eventually for involuntary load shedding.

The scarcity price levels for missing AS targets are set following the scarcity prices used at the CAISO (CAISO, 2009). The scarcity price levels for the different reserves ensure that non-spinning reserve targets are missed before the higher quality spinning and regulation reserve targets are missed. The assumed loss of social welfare for involuntary load shedding is a value that falls within the wide range ($1,000/MWh to $100,000/MWh) of commonly cited estimates of the value of lost load (VOLL) (Stoft, 2002).[16]

[14] Another promising option for simplifying commitment decisions in long-term planning studies, but is not used here, is outlined by Palmintier and Webster (2011).

[15] Price responsive demand could also be used to balance supply and demand. However, in this report the elasticity of demand is assumed to be quite inelastic (with a constant elasticity of -0.001 up to the VOLL). In a later report demand will be assumed to be more elastic in a scenario that investigates the long-run impact of real-time pricing with high VG penetration.

[16] The choice of the loss of social welfare associated with involuntary load shedding and missing reserve targets impacts the number of hours of the year where the available generation is less than the demand (leading to hours with scarcity prices) which in a reliability based study would impact the loss of load expectation (LOLE). If a low value is chosen for the VOLL then the

- Non-spinning reserves: \$500/MWh
- Spinning reserves: \$1,000/MWh
- Regulation reserves: \$2,000/MWh
- Involuntary load shedding: \$10,000/MWh

3.1.4 Revenues

All generation resources are assumed to participate in the DA market (and to be paid accordingly at a rate of $p_{DA}Q_{DA}$), but also to pay for (or to be compensated for) RT deviations from the DA schedule $(Q_{RT} - Q_{DA})$ at the RT price (p_{RT}). The total revenue (TR) earned by each resource in each hour is:

$$TR = p_{DA}Q_{DA} + p_{RT}\left(Q_{RT} - Q_{DA}\right) \tag{1}$$

Though not shown here for clarity, and explained more in Appendix C, the revenues also include sales of ancillary services in the RT and DA market by conventional generation and CSP_6 at the corresponding RT and DA prices for AS (including regulation, spinning, and non-spinning reserves). The other VG technologies can only sell the regulation down AS and are further charged for increasing the AS requirements. The cost of the additional AS for the other VG technologies is subtracted from the revenues earned by the VG technologies based on the hourly contribution to the additional AS requirements and the hourly AS price.[17]

As can be seen from the formulation of the total revenues in Equation 1, generation that does not deviate from the DA schedule in RT will be compensated for all of the generation at the DA price. Generators that are not needed in the DA but then are required in RT are compensated for all of their generation at the RT price.

Variable generators that have a DA forecast that exceeds the actual RT generation are assumed to "buy" power equivalent to the deviations in RT at the RT price. If the lower amount of generation than expected causes the system to dispatch more expensive generators than would otherwise be needed in RT (e.g., a quick start CT is needed in RT but was not needed DA) then the cost of buying the power in RT at the RT price can exceed the payment that the variable generator earned in the DA for the overforecast of variable generation.

Conversely, variable generators with a DA forecast that is lower than the RT generation are assumed to "sell" power equivalent to the deviations at the RT price. If the greater amount of generation than expected causes RT prices to be lower than the DA price then the revenues earned from selling the deviations in RT can be lower than the revenues the variable generator could have earned if the DA VG forecast was correct and power equivalent to the deviations were sold at the DA price.

Finally, variable generators can in some hours earn more than what they would have earned if perfectly forecast. This occurs any time that a RT deviation from the DA happens to be in the direction of system need (e.g., if the RT generation exceeds the DA forecast generation at a time when the system needs more power

number of hours with scarcity prices and the LOLE will increase. A high VOLL, on the other hand, causes the number of hours with scarcity prices and the LOLE to decrease. As described later in Section 5.1 the choice of these scarcity prices leads to scarcity prices occurring approximately 0.8% of the year (about 70 hours per year) or less. If planners were to desire fewer hours with scarcity prices, the VOLL estimates would need to be increased or some other mechanism would need to be used to ensure adequate generation capacity were available (i.e. resource adequacy obligations). We note that controlling the number of hours where demand exceeds generation (the level of reliability) is important from a system planning/reliability perspective, but for the purposes of examining how the marginal economic value of variable generation changes with increasing penetration it is less important to identify the generation capacity needed to meet a absolute target level of reliability. Instead, what is important in this analysis is ensuring that the relative level of reliability remains similar across scenarios even with changes in the amount of variable generation. By maintaining the same scarcity prices and keeping the system in long-run equilibrium at all penetration levels of VG we maintain the relative level of reliability.

[17] There is some controversy regarding how to estimate the costs of ancillary services due to variable generation and much more controversy regarding how to allocate those costs between different generators or loads (e.g., Milligan et al., 2011). The simple method used here to estimate the short-run profits accounting for contribution to AS requirements is one of many options. The focus of this report is to examine the relative economic impact of these different requirements, not to examine in detail methods for allocating these costs.

than expected in the RT, then the variable generator can earn additional revenue due to the deviations). The overall difference in the revenue earned by variable generation that cannot be perfectly forecast from the revenue that could have been earned if RT generation always exactly matched the DA schedule makes up the cost of DA forecast errors for variable generation that is discussed later in Section 3.4.

Using Equation 1 to estimate the revenues for variable generators reasonably follows the approach used in most organized wholesale markets (i.e., ISO/RTO markets) in the U.S. (ISO/RTO Council, 2010). Some organized markets have programs, such as the California ISO Participating Intermittent Resource Program, that help minimize costs associated with RT deviations. On the other hand, many transmission system operators outside of ISO/RTO markets apply punitive imbalance charges for deviations from scheduled generation (Rogers and Porter, 2011). In keeping with the approach used in most ISO/RTO markets, VG RT deviations in this model are settled at RT prices without any consideration of punitive imbalance charges.

The revenues in Equation 1 do not include any sort of capacity payment, instead all revenues earned by resources in the power market are earned through sales of power and ancillary services, similar to an "energy-only" market. This is just a modeling choice: it would be possible to obtain the same results by replacing the revenues that are earned during hours with scarcity prices by an equivalent "capacity payment" that depends on the contribution of generation resources during periods where generation capacity is limited. For example, the energy and ancillary service prices could be capped at $500/MWh and capacity payments would equal the difference in revenue if the capacity prices were not capped at that low level. While the choice of capacity payments or reliance on an "energy-only" market design is a simple choice for a model, the choice of mechanism to ensure adequate investment is much more important in real-world conditions due to issues like market power and risk associated with investment with long-term uncertainty (Stoft, 2002).

3.1.5 Low Price Periods and Curtailment

During some periods of the year too much generation in the DA or RT market can cause prices to drop to very low levels. During times with very low prices, variable generators, which have very low or zero marginal generation costs, may become indifferent between generating power and being compensated at the very low wholesale price for power or not generating at all. In this analysis, we assume (both for simplicity and so as to not forecast policy outcomes for 2030) that production-related incentives that are used today are no longer available for variable generation (e.g., the production tax credit (PTC) and renewable energy credits (RECs) are not used). Without these production incentives there is no opportunity cost associated with curtailment of VG when the wholesale power price drops to zero. VG is also indifferent to curtailment when the DA price is positive yet the RT price drops toward zero since, as shown by Equation 1, when the RT price is zero the RT generation can deviate from the DA schedule by any amount without penalty. In the case where the DA price is positive and the RT price is zero, VGs earn the same revenue whether curtailed in RT or not. To account for this situation, the dispatch model only curtails VG when the system cannot economically absorb additional VG and the price for power is zero.

The curtailment that is calculated in this analysis is only due to system flexibility issues and does not reflect curtailment that would occur due to insufficient transmission capacity between variable generation and loads. Current wind curtailment in U.S. power systems is due to a mixture of flexibility and transmission related factors, but transmission is the primary cause of curtailment (Wiser and Bolinger, 2011). The results from this analysis will not capture curtailment related to transmission.

In addition, since no production related incentives are included for VG in this analysis prices do not become negative in times of high VG generation. Had production incentives been included in the analysis there would be an opportunity cost associated with being curtailed. VG would then only be indifferent between curtailment and continuing to generate and earn the production related incentive if the wholesale power prices were to become negative.

3.1.6 Virtual Load

Virtual load bids were added to the DA process when average DA prices were found to differ from average RT prices. Ideally DA and RT prices should be approximately equal when averaged over a long period because an arbitrage opportunity exists between the DA and RT market when average prices are not equal. A generator that expects that average RT prices will be consistently greater than the average of DA prices would have the incentive to not participate in the DA market (or bid a very high cost so that they receive a DA schedule that has them not generate) but then make the generation available in the RT to capture the higher RT prices. Many organized markets allow market participants to use virtual bids to arbitrage between DA and RT markets to reduce these systematic deviations between DA and RT prices and therefore increase the overall efficiency of the power market (Isemonger, 2006).

A virtual load in the DA would appear to increase the DA load and increase the amount of generation that would be scheduled in the DA market. The actual RT load would be lower than the DA load since the virtual load from the DA would not show up in RT. This lower load in RT would tend to decrease RT prices. A market participant would find it profitable to bid virtual load in the DA as long as the RT price is greater than the DA price on average. The virtual load would "buy" a quantity of load (L_{vl}) at a price of p_{DA} and, since the load would not show up in RT, it would "sell" a RT deviation from the DA schedule of L_{vl} at the RT price (p_{RT}). Since the revenues from selling the virtual power in RT ($L_{vl}p_{RT}$) exceed the cost from buying the virtual power DA ($L_{vl}p_{DA}$) when the RT price exceeds the DA price ($p_{RT} > p_{DA}$) the virtual load bid is profitable. If too much virtual load is bid in the DA, however, the DA price will increase and eventually exceed the RT price. Virtual load bids would then be unprofitable since power would be bought DA at a price greater than the power was sold in RT.

Without the virtual load bids, the average DA and RT prices in our analysis were found to differ because, in general, there is an asymmetry associated with the cost of managing under-forecasts versus over-forecasts of variable generation. When the DA forecast of VG exceeds the actual RT VG the cost associated with backing down on-line generation, changing the dispatch of hydro or storage, or in extreme cases curtailing VG were not too high. On the other hand, when the DA commitment is made with the expectation that the DA forecast of VG will contribute in RT, and when actual VG in RT is lower than the DA forecast, there are often periods where the costs of dealing with under-forecasts were fairly high. After dispatching upward any available on-line capacity, for example, the remaining options for dealing with a shortage of generation in RT involved dispatching hydro and storage away from what would otherwise have been more profitable periods, starting any available quick-start CTs, missing reserve targets at the predefined social welfare cost (as described earlier in this section), or involuntary load shedding at the VOLL. The higher recourse cost associated with managing under-forecasts relative to the costs associated with over-forecasts leads average RT prices to exceed average DA prices when DA commitment decisions are based strictly on forecasted VG. Such an asymmetry in balancing costs has also been reported for real power markets (Skytte, 1999; Morthorst, 2003).

One solution to reduce the difference between average DA and RT price, as noted earlier, is to over-commit resources in the DA through the use of virtual load. A small amount of virtual load in hours with VG would increase the other generation resources available to be dispatched up when the RT VG is below the DA forecast. The right amount of virtual load to include, however, is not an easy task to determine. Methods like stochastic unit-commitment use several scenarios to determine the optimal DA commitment given uncertainty in RT generation (Bouffard and Galiana, 2008; Tuohy et al., 2009; Ruiz et al., 2009; Meibom et al., 2010; Papavasiliou et al., 2011; Wang et al., 2011). In this study, however, only one DA forecast scenario was used. As a result, in this study, the amount of virtual load included in each case was empirically found by increasing virtual load bids up to the point that there was near zero average profit (or losses) associated with virtual load bids over the course of a one-year simulation period (indicating that the systematic arbitrage opportunity was largely eliminated).

The shape of the hourly virtual load bids were a fraction of the DA forecast for VG (in the case of wind, PV, and CSP_0) or historic hourly load (in the case of CSP_6). The decision to use a fraction of the historic hourly load in the case of CSP_6 was based on early experimentation with the model. As an example from the model used in this report, in the case with 15% PV the average DA price exceeded the average RT price by \$11/MWh if no virtual load was included in the DA. When 14% of the DA forecast of PV generation was included as virtual load in the DA the difference between the average DA price and the average RT price decreased to \$2/MWh. This overall approach appeared to mitigate obvious issues with differences in average DA and RT prices, but this is an area where additional work should be focused in order to improve power market simulation methods with significant penetrations of VG.

3.2 Investment

An important feature of this analysis is that the detailed operational impacts of VG are always based on a system that is in long-run equilibrium for the given amount of VG. As described in Section 2, other studies have often examined the operational impacts of VG by adding VG to a system that was originally designed to meet future load but without consideration of the potential for significant additions of VG to the system. Or, conversely, studies that have examined the long-run impact of VG have ignored or downplayed the operational constraints of conventional power plants and therefore at least partially ignored integration concerns.

In this study, the system is considered to be in long-run equilibrium when the conventional power generation that has not reached the end of its technical life (the incumbent generation) is either able to earn enough revenue to justify staying in the market, or the generation retires for economic reasons, and any new conventional generation that enters the market is able to cover its annualized fixed cost of investment. In other words, the short-run profit of incumbent generation that stays in the market must exceed its fixed O&M cost and the short-run profit of new generation must equal the fixed investment and O&M cost of that generation. The short-run profit (SR_π) is defined as the difference between the total revenues (TR) from selling power (and ancillary services) in the power market and the variable cost ($VC(Q_{RT})$) of producing that power (including fuel costs, start-up costs, emissions costs, and variable O&M costs).

$$SR_\pi = \sum_{t \in T} \left(TR_t - VC_t \left(Q_{RT} \right) \right) \tag{2}$$

With these conditions met, the non-VG system is in long-run equilibrium because all incumbent generation that stays in the market has an economic incentive to remain in the market, no additional new generation would find it profitable to enter the market (because then prices would decrease and the generation would not be able to cover its investment costs), and no already added new generation has an economic incentive to leave the market (because those plants can cover their costs in the market and if these generators exited then prices would go up and some other generation would take its place in the market).

Simulating a system in long-run equilibrium is insightful because it indicates how power market rules and operational practices influence prices and investment decisions in the long term. It is also important to understand, however, that real power markets are never exactly in long-run equilibrium. Real investments are lumpy and power plants take time to build, fuel prices and investment costs change in unpredictable ways, market participants sometimes exercise market power, and regulatory interventions often affect prices and investment decisions. More detailed, dynamic models have been developed to explore these factors (absent the complicating contribution of high penetrations of variable generation) (e.g., Botterud et al., 2005; Murphy and Smeers, 2005; Olsina et al., 2006; Hobbs et al., 2007).

Any model of a power system makes certain simplifying assumptions in order to investigate the interactions between variables and parameters in the model. In this study the long-run investment model is simulating a world where long-run non-VG investments are made in a competitive manner based on the average performance of the investments over a year with a particular level of VG penetration. The dispatch over the year is simulated with a candidate set of investment generation. With each set of candidate generation capacity the same year of hourly load, hourly VG generation, VG forecast errors, and monthly hydro power generation budget are simulated.

When insufficient generation exists in the candidate portfolio the prices spike to high levels many times per year. The high prices signal the need for more generation in the candidate portfolio. When too much generation is in the candidate portfolio the prices collapse such that there are few if any scarcity pricing events within the year. The low prices signal too much generation in the candidate portfolio. In this way the long-run equilibrium is found based on repeated deterministic simulations of data that is inherently uncertain (including the load, VG production, VG forecast errors, and monthly hydro budget). The only

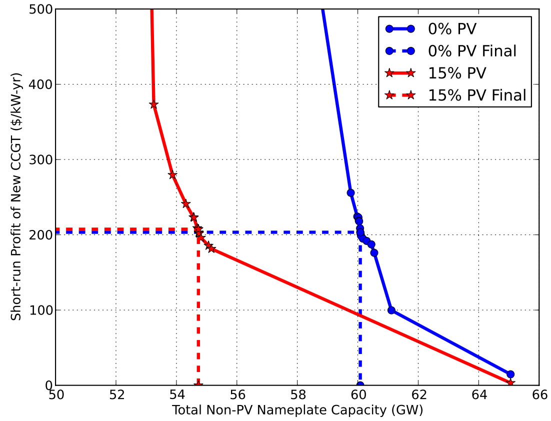


Figure 2: Relationship between short-run profit of new CCGT generation and total non-VG nameplate capacity with 0% and 15% PV.

uncertainty that is captured in this model, then, is with regards to day-ahead commitment decisions based on inaccurate day-ahead forecasts.

In reality, investment decisions must be made with significantly more uncertainty than is captured here (including fuel price uncertainty and capital cost uncertainty), and may be affected by regulatory interventions that are not modeled in the present analysis. Nonetheless, the simulations presented in the report indicate what could happen if market participants use the outcome of generation investment decisions in the previous year to adjust investment decisions for the next year. With repeated opportunities to adjust investment decisions, coupled with relatively stable load and amounts of VG installed capacity, the simulation results should mimic investment decisions that would be made by market participants within the economic framework considered.

To illustrate the operation of the model in one case, the performance of generation in terms of short-run profit earned over a year with different candidate sets of generation and for two different levels of PV penetration is shown in Figure 2. The short-run profit of new CCGT generation is shown on the vertical axis and the total non-PV nameplate capacity is shown on the horizontal axis (which includes incumbent pumped hydro storage, hydro, nuclear, geothermal, CCGTs, natural gas steam turbines, and CTs along with varying amounts of new CCGTs). The annualized investment and fixed O&M cost of new CCGT resources is approximately $200/kW-yr in this case.

When too little generation is available in the candidate set, the high short-run profits of CCGT resources, well above $200/kW-yr, show that additional new CCGT generation investments are profitable. When too much generation is available in the candidate set, the low short-run profits, below $200/kW-yr, mean that some of the generation in the candidate set is not able to cover its investment cost and should not be built. The final candidate set of generation is such that the short-run profit of the new CCGTs that are in the portfolio is equivalent to $200/kW-yr.

With the final candidate set of generation resources in this specific case, the other new investment options, including new CT, new coal, new nuclear, and new storage resources, all had short-run profits that were lower than their respective annualized investment and fixed O&M cost. These other options were therefore not included in the final set of generation resources. All of the incumbent generation, on the other hand, were able to cover their fixed O&M cost and therefore were also included in the final set of generation resources. Note that in other scenarios, however, combinations of different resource options can be and are added. Additional detail regarding how the investment algorithm decides which generation resources to include in the candidate sets of generation, including how the algorithm deals with combinations of multiple new investment options, is provided in Appendix B.

The effect of adding VG to a system, in this case PV, is that it makes some of the generation capacity that would be built if there were no PV (i.e. the investment decisions for 0% penetration) unable to cover the cost of new investment. This is shown in Figure 2 by the lower short-run profit of the new CCGT resources with 15% PV relative to the short-run profit of the same amount of generation in a case with 0% PV. As a result, with the additional PV generation, less CCGT is added to the final candidate portfolio of generation. If too little CCGT generation is added in the case with 15% PV penetration, however, the prices will again rise and increase the short-run profit of new CCGT resources. In the end, the short-run profit of the CCGT generation in the final candidate set of generation with 15% PV is the same as the short-run profit of the new CCGT in the final candidate set of generation with 0% PV.

3.3 Implied Capacity Credit

The change in the total amount of non-VG capacity that is included in the final candidate set of generation resources relative to cases with less VG represents the amount of generation capacity that VG displaces. In traditional planning studies with VG, the amount of conventional generation that can be displaced without reducing the level of reliability relative to what it would have been without the VG is sometimes called the capacity credit or the capacity value of the VG (Garver, 1966; Billinton et al., 1996; Milligan, 2000; Kahn, 2004; Milligan and Porter, 2006; Amelin, 2009; Keane et al., 2010; Hasche et al., 2011; Madaeni et al., 2012b).

In this study, the implied capacity credit is a result of the investment decisions and the impact of those decisions on dispatch rather than a detailed reliability analysis. The use of scarcity pricing during periods with insufficient generation capacity to meet loads, as described earlier in Section 3.1, is a proxy for indicating periods with high loss of load probability (LOLP), a common metric used in reliability studies. In a reliability study the sum of the loss of load probability over a period drives the loss of load expectation (LOLE) in a similar way that the sum of the scarcity prices over a period drive the short-run profits of a peaking plant. In a reliability study the LOLE is kept constant across cases that are meant to have the same level of reliability whereas in this study the short-run profits of generation that is built to meet peak loads is kept constant at the annualized fixed cost of investment across many scenarios. While investment decisions in this study are based on a fundamentally different approach than an explicit LOLP-based reliability analysis, it is clear that the relationship between displaced conventional generation capacity and additional VG follow similar drivers. This relationship is illustrated in more detail using a model of a simple power market that is much more simple than the power market modeled in this report in Appendix F.

In fact, one analysis that explicitly draws a link between investment decisions in a system where insufficient generation in periods leads to outage costs equal to the value of lost load (VOLL) and reliability based on LOLP is a paper by Chao (1983). The investment decisions in the model used in our analysis are built on similar intuition. The implied capacity credit of VG estimated in this analysis should therefore follow similar trends as what would be found with a detailed reliability analysis. However, for actual planning purposes a detailed reliability analysis that accounts for forced outages, required maintenance, and time to repair should be carried out.

3.4 Estimation of Long-run Value

In each case once the long-run equilibrium of non-VG resources has been determined, the system is dispatched a final time over the full year of hourly data using the final candidate portfolio of generation resources. Because the final non-VG portfolio is in long-run equilibrium, the prices for energy and ancillary services in the final dispatch represent the long-run marginal value of energy and reserves in each hour for the given level of VG penetration. The short-run profit earned by any resource that generates power when the system is in long-run equilibrium is therefore defined in this report as the marginal long-run economic value of that resource. For any new investments in non-VG resources that are part of the portfolio, the "market test" mentioned earlier in Section 2.1 results in the short-run profit being approximately equivalent to the fixed cost of investment and fixed O&M cost. Similarly, the short-run profit of VG resources can be compared to the fixed cost of investment to determine if it would be economically valuable to build more of that VG resource using the same "market test". In the case of VG, the short-run profit earned in this final dispatch represents the marginal economic value of that VG resource.

Since the prices that result from the dispatch of the system reflect the marginal value in that hour, the long-run marginal economic value calculated in any scenario indicates the value of adding a small increment of power with the same hourly generation profile. The marginal value does not, however, indicate the average value of all power that is produced by VG resources. For example, as will be shown in Section 5.2, the marginal value of most VG resources is lower when the system is at 10% penetration of VG than it is when at 0% penetration of VG. The marginal value of VG at 10% penetration indicates the value of increasing penetration beyond 10% while the greater marginal value at lower penetration levels indicates that the average value of all VG added to get to 10% penetration is greater than the marginal value at 10% penetration. The average value is useful for comparisons of average costs and benefits while the marginal value is useful for determining if there would be economic value to increasing the penetration from the predefined penetration level.

Because the marginal economic value of power is based on prices that result from a system that is in long-run equilibrium, the marginal economic value reflects both the value of displacing fossil fuel and the value of displacing the need for new conventional generation capacity. In contrast, a study that simply adds significant VG to a power system that is in equilibrium without VG is only reflecting the short-run economic value. In that case, the prices will fall below equilibrium levels and generators that were built to provide services to the system in a case with no VG will no longer be able to justify their investment costs in a system with high VG penetration. The system, in that case, would be far from equilibrium. Over the long life of a VG power plant, the long-run value is more useful for evaluating the benefits of VG because the short-run value reflects the temporary conditions of an out-of-balance system.

3.4.1 Decomposition of Marginal Economic Value

In addition to exploring how the marginal economic value of VG changes across technologies and with increasing penetration, it is important to understand what factors contribute to changes in the marginal economic value with penetration. Understanding what drives changes in the marginal economic value can help inform a search for market reforms or technological changes that can help mitigate decreases in economic value with increasing penetration, as will be discussed in a future paper.

In this study we choose to decompose the marginal value of VG into four separate and additive components: capacity value, energy value, day-ahead forecast error, and ancillary services. The definition of these components and the methods used to estimate each component differ from approaches sometimes used in other studies, particularly regarding the AS cost and DA forecast error cost. The values found in this report using this decomposition approach, however, do not appear to be out of line with values available in the other studies.

- Capacity Value ($/MWh): The portion of short-run profit earned during hours with scarcity prices (defined to be equal to or greater than $500/MWh).
- Energy Value ($/MWh): The portion of short-run profit earned in hours without scarcity prices, assuming the DA forecast 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 VG and paying for increased AS due to increased short-term variability and uncertainty from VG.

The capacity value reflects the contribution of VG to balancing supply and demand when generation is scarce. In particular, the periods with scarcity are defined to be periods where the price of energy rises to or above $500/MWh, the lowest scarcity price level for missing AS targets.[18] As will be described more in

[18] The choice of the price level that differentiates between prices that are categorized as scarcity prices and non-scarcity prices impacts the decomposition of the marginal economic value into "capacity value" and "energy value", but the choice does not impact the overall total marginal economic value.

Section 5.1, periods with scarcity prices are infrequent with the final candidate portfolios: less than 1% of the year has scarcity prices in all cases considered in this analysis.

Even though scarcity prices are infrequent, they play an extremely important role in determining the short-run profit of new investments. The short-run profit earned by new CCGT resources during periods with scarcity prices, for example, is equivalent to 85–95% of the total short-run profit earned over the year in most cases.[19] During periods with scarcity prices the price of energy far exceeds the variable cost for CCGT plants, leading to high short-run profit in these hours. In addition, in some hours CCGT resources are operating while more expensive CT resources are at the margin, leading to additional short-run profit.

In contrast, for most of the rest of the year the price of energy is found to be nearly equivalent to the marginal variable cost of the CCGT (and the CCGT is on the margin) or the price is found to be below the marginal cost of production (meaning that the CCGT resources will typically be off-line or at minimum generation). In these hours the CCGT resource earns almost no short-run profit. Note that in a sensitivity case with no retirements, presented later in Section 5.4, additional low efficiency natural gas steam turbine plants remain in the power market which makes the short-run profit of CCGTs less dependent on scarcity prices compared to the reference scenarios. Furthermore, across all scenarios, the short-run profit of VG are less dependent on scarcity prices than CCGTs in part because VG technologies have zero variable costs.

The energy value is the remainder of the short-run profit earned by VG assuming perfect DA forecasts. Additional generation by VG would displace energy from the marginal resource in these hours, and the energy value then reflects the avoided fuel, emissions, and variable O&M costs from the generation that is displaced by VG, again based on an assumed perfect DA forecast of VG.

Day-ahead forecast error cost is the cost of deviations from the DA schedule paid at the RT price. This cost reflects the impact of RT deviations from the DA schedule in each hour. If the value is positive then the RT deviations contribute to meeting system needs and this is an additional value (e.g. solar thermal storage being re-dispatched in RT can help mitigate system conditions). If the value is negative, then the day ahead forecast error represents the cost that the RT deviations impose (i.e. wind forecast errors on average increase cost).

The ancillary service component reflects the net value from a resource providing AS to the system (e.g., regulation down provided by wind or solar) and the additional burden of a resource in requiring an increase in the procurement of AS (e.g., regulation) to manage intra-hour variability. A negative value indicates a net cost: the expense of procuring additional AS due to the variability of VG exceeding any revenue earned by VG for selling AS. The costs that are attributed to VG reflect the assumption that AS requirements change in proportion to the DA schedule for VG. The amount of AS added to compensate for the additional short-term variability and uncertainty of VG is described in Section 4.

4 Data and Assumptions

This report focuses on a case study of adding increasing amounts of VG to a power system based on load, VG profile, and capacities of incumbent generation that loosely correspond to California in 2030. We are only using selected data from California primarily based on existing generation and historical load profiles. We are not attempting to exactly model many elements that impact California including the detailed CAISO market rules, imports, procurement and contracting policies, and emissions regulations, among other factors. The results reflect these assumptions which mean that not only would these results be different in other regions, they are not meant to exactly model California either.

The only load and conventional generation resources that are considered are for the California NERC sub-region; load and conventional generation resources defined by NERC as outside of the California NERC sub-region are ignored.[20] The generation profiles for VG, however, include some resources that are located

[19]The exception to this are cases with high penetrations of CSP with 6 hours of thermal storage. In these cases the normal peak-load pricing model no longer applies since the system becomes increasingly energy-limited rather than capacity-limited. As will be described later, this is an area that is worth additional research.

[20]In reality California is a net-importer of power from other regions in the WECC from power plants that are not considered by NERC to be part of the California sub-region. Imports in 2010 included renewable power, coal power, large hydro power, natural

outside of California based on the site selection process described in the next section. These resources are assumed to be dynamically scheduled into California such that all of the variability and uncertainty, including within-hour, is managed within the state.

4.1 Variable Generation

The VG profiles and DA forecasts are based on hourly data corresponding to the historical generation profile estimated for the year 2004. Other choices of the historical generation years for VG and load were not tested in this study. Future research could examine the sensitivity of the results to the choice of historical year or the number of years chosen for analysis. The wind generation profiles and forecasts for each 30 MW wind site used to reach the target wind penetration level are based on the dataset derived for the Western Wind and Solar Integration Study (WWSIS) (Potter et al., 2008).

The solar generation profiles are based on hourly satellite derived insolation data from the National Solar Radiation Database (NSRDB).[21] Each solar site used to reach the target penetration level is located at one of the 10 km $\times$ 10 km grid points included in the NSRDB. Each PV site is assumed to have a 100 MW nameplate capacity (AC) and each CSP site is assumed to have a 110 MW nameplate capacity. For PV the insolation data are converted into PV generation profiles using the NREL System Advisor Model (SAM). The PV data are based on single-axis tracking PV that is tilted at an angle of the PV site latitude. For CSP the insolation data are converted into thermal heat generation in the solar field using SAM. The solar plant is then dispatched within the dispatch model based on a method similar to Sioshansi and Denholm (2010).[22] The solar field multiplier (the ratio of the peak power output of the solar field relative to the nameplate capacity of the solar plant power block) is assumed to be 1.25 for CSP_0 and 2.5 for CSP_6. DA forecasts of solar insolation from the WWSIS are also converted into DA forecasts of generation for PV and solar field heat for CSP resources. DA solar forecasts were only generated on a 20 km $\times$ 20 km grid in the WWSIS. Individual solar sites on a 10 km $\times$ 10 km are then assigned forecasts from a nearby site on the 20 km $\times$ 20 km grid. This approximation will tend to overstate the correlation of DA forecast errors and potentially the DA forecast error costs for solar.

Note that the solar and wind DA forecasts are point forecasts developed in the WWSIS using numerical weather models. Increasingly studies of unit-commitment and scheduling with variable generation are using stochastic unit-commitment methods that rely on several different forecasts in order to represent the uncertainty inherent in day-ahead forecasts rather than relying on one point forecast, as discussed in Section 3.1.6. Evaluating the impact of stochastic unit-commitment on the long-run value of VG is left for future research.

The actual generation profiles for the VG resources that were modeled in each of the scenarios were selected from the resources identified in the Western Renewable Energy Zone Initiative (WREZ) (Pletka and Finn, 2009). The resources were picked by ranking all of the WREZ resources by their relative economic

gas power, nuclear power, and unspecified sources of power (`http://energyalmanac.ca.gov/electricity/total_system_power.html`). Estimating the role of imports in 2030 in California would require assessing plant retirements in 2030, modeling transmission between California and the rest-of-WECC in 2030, and projecting renewable penetration levels for the rest of WECC. This level of detail was not included in the model. Depending on how much of the out-of-state coal retires by 2030, access to more out-of-state coal would tend to lower the economic value of variable generation at high penetration since coal would be displaced instead of more expensive natural gas. Access to more out-of-state nuclear would also lower the economic value of variable generation at high penetration levels. Access to out-of-state large hydro in the Pacific Northwest and along the Colorado River would potentially increase the resources available to manage variability and uncertainty in some hours but it could also reduce flexibility in low load hours depending on the minimum flow constraints of out-of-state hydro. Access to out-of-state natural gas would raise or lower the economic value of variable generation depending on the heat-rate and flexibility of the out-of-state natural gas relative to the heat-rate and flexibility of the in-state natural gas.

[21] `ftp://ftp.ncdc.noaa.gov/pub/data/nsrdb-solar/`

[22] The key difference with the CSP dispatch approach used in this report is that the CSP sites are grouped together into a CSP vintage and decisions regarding how much CSP to bring on-line are linearized rather than the binary on/off decisions modeled for an individual CSP plant in Sioshansi and Denholm (2010). The linearization used in this report is a simplification that is used to maintain reasonable dispatch solution times at the expense of more accurate representation of individual power plant decisions.

attractiveness[23] to load zones in California[24] and then selecting the most attractive resources of the type of VG being considered up to the desired penetration level. As a result of this procedure, solar resources were all selected from high-quality solar resource hubs in California with some additional solar from Arizona hubs in cases with more than 20% solar penetration. Wind resources were similarly selected from California hubs at low wind penetration levels. At 10% penetration additional wind resources were selected from hubs in Oregon, Arizona, Nevada, and Utah. At 20% penetration additional wind resources were selected from Washington, Wyoming and Idaho, and for 30% penetration and above wind resources were selected from New Mexico as well.

4.2 Load

Historical hourly demand data for 2004 (in order to match the solar and wind data) are based on the aggregated demand reported for all of the transmission zones that are assigned to the California NERC sub-region.[25] The historical load profile for 2004 is increased to estimate demand in 2030 by applying a constant growth factor of 1.16 to all hours of the historic year.[26] The peak load in 2030 based on scaling the historical California load shape from 2004 is 63 GW. Demand is treated as nearly inelastic in this case study with an assumed constant elasticity of demand of -0.001 up to the assumed value of lost load ($10,000/MWh).

4.3 Hydropower and Pumped Hydro Storage

Hydropower is challenging to model accurately due to the many non-economic constraints on river flows downstream of the plant and the variable river flows upstream of the plant. Furthermore, detailed historical hydro data showing constraints and hydro plant parameters are rarely available in the public domain. In this analysis hydro is dispatched between the total nameplate capacity of hydro in the California NERC sub-region and a minimum generation constraint that varies by month as described below. The current nameplate capacity of hydro generation in California is 13.3 GW. All of this hydro capacity is assumed to be available in 2030. Additional investments in hydro are not considered in the investment model.

The amount of total hydro generation in California that is assumed possible each month (the hydro generation budget) is based on the total actual hydropower generation within the California NERC sub-region during the same calendar month from the median hydropower generation year for the years of 1990 through 2008.[27] The historical hydropower generation data were collected from Ventyx. The minimum hourly hydro-flow constraint each month is based on the average hourly generation rate that would lead to the lowest monhtly total hydro generation measured between 1990 and 2008 in that same calendar month.

The reasonableness of the hydro assumptions were checked by comparing hydropower generation duration curves for a modeled case (with no variable generation) to a short hourly record of aggregated hydropower production in the CAISO.[28] The shape of the modeled hydropower generation shows more time at maximum generation and minimum generation relative to the time spent at minimum and maximum for the actual hydropower generation. This could partly be explained by 2010-2011 being higher than median hydro years, but it may also be due to hydro constraints that are not captured in this analysis.

The 3.5 GW of existing pumped hydro storage (PHS) capacity in California is assumed to be available in 2030. The reservoir capacity is assumed to be equivalent to 10 hours of storage capacity at full power

[23]Specifically, the resources were ranked by the adjusted delivered cost estimated in the WREZ Peer Analysis Tool (`http://www.westgov.org/rtep/220-wrez-transmission-model-page`). This metric includes the bus-bar cost of the resource, a pro-rata share of a new 500 kV transmission line between the resource hub and the load zone, and a simplified estimate of the market value of the power to the load zone.

[24]The California load zones included in the WREZ Peer Analysis Tool included Sacramento, San Francisco Bay Area, Los Angeles, and San Diego.

[25]The demand data were collected from Ventyx Velocity Suite, hereafter referred to as Ventyx.

[26]The growth factor is based on an extrapolation of the annual growth rate between 2015-2020 estimated by WECC (which adjusts load forecasts for expected energy efficiency measures) to the period between 2005-2030.

[27]The median hydropower generation was used in this study but data were collected to be able to examine the impact of high hydro or low hydro years on the estimated economic value of variable generation.

[28]The available hourly hydro generation data between 2010 and the end of 2011 were extracted from the CAISO website at `www.caiso.com/green/renewableswatch.html`

(35 GWh). The round-trip efficiency of the pumped hydro is assumed to be 81%. Inflow into the pumped hydro storage from direct precipitation onto the reservoir or runoff from area surrounding the pumped hydro storage reservoir is assumed to be negligible.

Both hydropower and pumped hydro storage are assumed to be able to provide ancillary services and both can earn high revenue during hours with scarcity prices as long as sufficient energy is available.

4.4 Thermal Generation Vintages and Technical Life

The existing WECC thermal generation fleet was grouped into several different vintages based on factors including fuel, plant size, and age. The thermal plant vintages were then used to derive average performance characteristics that are used in the dispatch model. The amount of incumbent generation within each vintage is based on the amount of generation that would still be operating in 2030 assuming typical plant technical lifetimes.[29] Generation that is older than the technical life in 2030 is assumed to be retired for technical reasons, while economic retirement decisions are based on whether or not the short-run profit of incumbent generation is sufficient to cover its fixed O&M cost, as described earlier in Section 3.2. A sensitivity scenario, presented in Section 5.4.4, examines the impact of the technical life assumptions by assuming that no existing generation is retired by 2030 for technical reasons.

4.5 Incumbent Generation Capacity

The resulting total incumbent generation in California in 2030 is 45.5 GW of nameplate capacity. In addition to the incumbent hydropower and pumped hydro storage, the incumbent thermal generation is grouped into two coal vintages, three CCGT vintages, one CT vintage, one natural gas steam turbine vintage, geothermal, and nuclear. Based on the assumed technical life, 5% of the incumbent generation capacity is coal, 35% is CCGT, 9% is CT, 0.2% is natural gas steam turbine (almost all of the existing natural gas steam turbine fleet is assumed to reach the end of its technical life by 2030), 10% is nuclear, 4% is geothermal, 29% is conventional hydropower, and 8% is existing PHS. Additional older vintages are included for the incumbent generation in a sensitivity case where there are no assumed retirements from the existing generation. These additional vintages are described in Appendix D. The appendix also provides more details on the data and assumptions used to model pumped hydro storage, and thermal and hydropower generation.[30]

4.6 Generation Operational Parameters

Standard thermal generation performance parameters[31] (including maximum and minimum generation, ramp-rates, part-load heat rates and emissions curves, and start-up heat) were derived based in large measure on the average historical performance of WECC thermal generators within the same plant vintage based on

[29]The technical life assumptions were as follows: 60 years for nuclear plants, 50 years for coal, natural gas steam plants and geothermal, and 30 years for CT and CCGT plants. The technical life of coal and natural gas steam plants is based on an analysis of historical plant retirement ages in North America using the Ventyx Velocity Suite database of plant ages and retirement dates; similar assumptions are used in other studies (Sims et al., 2007; IEA, 2010). Fewer retirements of CTs and CCGTs were available from the historical Ventyx data, and instead a technical life of 30 years was assumed based on the technical life presented by IEA (2011). The technical life for nuclear plants is based on an original license life of 40 years with a single 20-year license renewal. A similar assumption was used in the 2010 EIA Annual Energy Outlook Alternative Nuclear Retirement Case (EIA, 2010).

[30]No existing wind or solar were included in the incumbent generation in order to be able to examine the marginal economic value of VG across a full range of VG penetration levels starting from nearly zero penetration. Existing biomass and combined-heat and power generation in California were also excluded from the analysis for simplicity. Biomass generation is similar to thermal generation in that there is often a non-negligible variable cost associated with generating energy. It differs from conventional generation however due to variability in resource availability and in demand for energy to satisfy policies external to the power market like the state RPS.

[31]A minimum run-time limit was not included since thermal generation is dispatched as a fleet in this analysis. The minimum run-time for an individual plant does not limit the minimum time a fleet of generation can operate with a given amount of generation online as the timing of when individual units were started and stopped could be staggered.

figures reported in the Ventyx Velocity Suite, as described in further detail in Appendix D.[32] The Ventyx data largely derive from actual historical plant performance measured hourly through the Continuous Emissions Monitoring System (CEMS) from the EPA. The Ventyx dataset does not quantify NO_x or SO_2 emissions during start-up that are in addition to normal emissions at part-load.[33] The NO_x and SO_2 emissions during start-up were therefore approximated as a ratio of the emissions at full load using the ratios reported by initial analysis of Lew et al. (2011).[34]

Ramp-rates for the CT vintage were found to be very low when using hourly data from the Ventyx dataset. In addition the Ventyx dataset does not include ramp-rates for hydro nor does Ventyx report non-fuel start-up costs. The ramp-rates for the CT vintage and for hydropower[35] along with the non-fuel start-up costs related to wear & tear for all thermal plants are therefore derived from the assumptions used in WECC transmission modeling (WECC, 2011). The non-fuel start-up costs for coal plants derived from the WECC assumptions are similar to the warm start costs (i.e., the plant is not down for longer than 120 hours) for coal plants reported by Gray (2001). More recent preliminary research on average "lower-bound" start-up costs for coal, natural gas steam turbines, CCGT, and CT plants by Intertek Aptech shows high variability depending on the way that plants are designed to operate and the degree to which investments are made to reduce start-up costs (Lefton, 2011). The Aptech research also indicates that the range of start-up costs from actual plants may be somewhat higher for coal plant and lower for CT plants than the assumed average costs used in this analysis. As non-fuel start-up costs are an area of ongoing research, this is an area where assumptions should be revisited as more detailed estimates become available.

The incumbent geothermal and nuclear plants were assumed to be inflexible and therefore not able to reduce their output from their nameplate capacity. Although there are examples showing that it is technically possible to ramp and cycle both some nuclear and geothermal plants,[36] it is assumed for simplicity that regulatory, policy, and practical restrictions prevent flexible operation. Even if these plants were modeled as being flexible, they would rarely be cycled due to the very low variable cost of the nuclear and geothermal resources; the wholesale price of power would have to drop below the low variable cost of these plants for there to be any economic benefit to cycling the plants.

The variable O&M costs for each vintage were based on averaging the Ventyx estimates for variable O&M cost for each WECC plant across the vintages. Where estimates were not available from Ventyx, estimates from WECC transmission modeling were used instead.

No consideration was made of planned and forced outage rates of generation in this analysis. This assumption is not expected to impact the relative changes in the marginal economic value of variable generation with increasing penetration. It will, however, tend to understate the capacity and energy value of VG. Irrespective of the VG penetration level this assumption will also tend to understate the absolute amount of conventional generation that is required to reach long-run equilibrium and low percentages of periods with scarcity prices and involuntary load shedding. Determining the actual amount of generation to build in 2030 will require the use of a reliability model that accounts for factors like conventional generation forced and planned outages.

[32]The thermal generator parameters used in this study are intended to be used in similar case studies of other WECC regions. Characteristics of all WECC generators were therefore used rather than focusing only on the characteristics of generation in California.

[33]CO_2 emissions during start-up can be estimated from the Ventyx data since Ventyx reports fuel combustion during start-up and CO_2 emissions are proportional to fuel combustion.

[34]The ratio of the start-up NO_x emissions to the full-load hourly NO_x emissions was 9.5 for a CCGT, 6.7 for a CT, and 2.9 for coal based on the analysis by Lew et al. (2011). The ratio of the start-up SO_2 emissions to the full-load hourly SO_2 emissions was only reported for coal by Lew et al. (2011). The ratio reported for the SO_2 emissions for coal, 2.7, was assumed to be the same for CCGTs and CTs in this analysis.

[35]The ramp-rates used here are more conservative than the ramp-rates that are reported for CTs and aggregated hydropower plants by (Makarov et al., 2008). This lower bound on ramp rate capabilities helps to reduce any bias that would otherwise be introduced by the fact that this study does not include any costs associated with ramping plants.

[36]Nuclear examples: A survey of cycling capabilities of steam plants concluded that limited nuclear cycling was a valid assumption (Fenton, 1982). The survey did report 6 nuclear power units, however, that were being turned down at night. The units could be turned down to as low as 50% of their capacity. Various occasions of the Columbia Generating Station, a nuclear power plant in the northwestern U.S., being turned down for economic dispatch have been reported (Rudolph and Ernst, 2010). There are also examples of geothermal plants being operated in a more flexible manner than strictly baseload (Brown, 1996; Grande et al., 2004).

4.7 Fuel Costs

Fuel costs for gas, coal, and uranium in 2030 are based on projections from the EIA in the Annual Energy Outlook, 2011 (EIA, 2011). The EIA gas price projection reflects recent reductions in expected gas prices due to the rapid growth of shale gas. While no sensitivity cases are used in this report to directly explore the impact of different gas prices on the economic value of variable generation, it should be recognized that uncertainty in future natural gas prices is a major source of uncertainty in estimating the absolute level of the marginal economic value of variable generation.

4.8 New Investments

This model allows for new investments in coal, CCGT, CT, nuclear, and PHS. The operating characteristics of the new investments (e.g., minimum generation, ramp rate, heat rates, emission rates, variable O&M costs, start-up costs, etc.) are assumed to be equivalent to the characteristics of recent vintages of incumbent plants that use the same fuel. The annualized capital cost and fixed O&M costs for all technologies except the PHS are based on a pro-forma financial model developed by E3 for WECC transmission modeling (WECC, 2010). The PHS annualized capital cost is based on EIA Annual Energy Outlook assumptions (EIA, 2010). No capital cost assumptions are made for wind and solar since these resources are forced in at different penetration levels. The variable O&M cost of wind and solar is assumed to be zero.

4.9 Ancillary Service Requirements

As described in Section 3.1, AS targets are included in the dispatch of the system in addition to energy demand. Market rules and operating procedures impact AS requirements and differ among power markets. Rather than explicitly modeling the AS requirements for a particular region or set of market rules, in this report the AS targets are based largely on the rules of thumb developed in the WWSIS (Piwko et al., 2010), with some minor adjustments made based on an examination of 1-min solar, wind, and load data synthesized for the CAISO 33% RPS analysis.[37] The rules of thumb developed in the WWSIS are largely based on examining the amount of reserves that would be required to meet three times the standard deviation of ten-minute changes in the net load. Implicitly, this reserve method assumes that sub-hourly dispatch is available and that day-ahead forecast errors dominate the uncertainty. Different reserve requirements would be needed for situations with different practices for scheduling and dispatching generation resources.

Hourly spinning and non-spinning reserves requirements are based only on the hourly load while hourly regulation reserve requirements are based on load and DA forecasts of VG. Similar AS requirements are applied for wind and solar (PV and CSP_0); a reasonable assumption based on previous analysis of 1-min data for wind and solar (Mills and Wiser, 2010). The AS targets are as follows:

- Non-Spinning Reserve: 4% of hourly load
- Spinning-Reserve: 2% of hourly load
- Regulation: 2% of hourly load plus 5% of day-ahead forecast of wind, PV, or CSP_0

The non-spinning reserves can be met by quick-start CT's that are off-line or by other resources that are on-line. The non-spinning reserves are assumed to be needed within 30-minutes. The amount of non-spinning reserve that a resource can offer is then based on how much it can increase its output in 30-minutes

[37] Data are available on the CAISO website under 33% Trajectory Case: Preliminary New Scenarios, One-Minute Data for Load, Wind and Solar. `http://www1.caiso.com/23bb/23bbc01d7bd0.html` The changes between the AS requirements used here and the rules of thumb developed in the WWSIS include (1) the WWSIS suggested an increase of reserves equivalent to 5% of the VG that would be split between spinning reserves and regulation reserves while this study allocates the full increase to regulation reserves and (2) the total amount of regulation and spinning reserves for hourly load was 3% of hourly load in the WWSIS while here it is 2% for regulation and 2% for spinning reserves. These adjustments were made in order to ensure that the regulation reserve requirement rules used in this model would be sufficient to cover the majority of the 1-min deviations of the 1-min data from interpolated 1-min data between hourly averages. Since this model uses only hourly average data, and does not explicitly model sub-hourly dispatch, these changes to the reserve rules act somewhat as a proxy to the resources that would be needed in sub-hourly dispatch.

given the ramp-rate limits of the resource. The spinning reserves can only be met by on-line resources and are assumed to be needed within 10-minutes.[38]

Regulation reserves are required in both the up and down direction, whereas spinning and non-spinning reserves are only required in the up direction. The regulation reserves can only be met by on-line resources and need to be fully deployable within 5-min. Additional details on how AS requirements are co-optimized with energy demand in the dispatch of generation resources are provided in Appendix C.

5 Results

The marginal economic value of wind, PV and CSP with increasing penetration of each variable energy resource in California is first explored by showing the total non-VG investment and the dispatch results for both VG and non-VG resources, including the implied capacity credit, changes in energy generation, emissions and curtailment. Variable generation profiles and the hourly prices for energy and ancillary services are then used to estimate the marginal economic value of variable generation. This marginal economic value is decomposed into capacity value, energy value, day-ahead forecast error, and ancillary service costs to show which factors contribute the most to changes in the marginal economic value with increasing penetration. Finally, sensitivity cases are used to explore how the marginal economic value would change for a system without flexibility constraints, with higher energy costs (by adding a carbon price), with lower capacity costs, and without retirement of currently existing generation. Future research will consider strategies to stem the decrease in the economic value of VG at high penetration such as price responsive demand, more flexible thermal generation, and lower-cost bulk-power storage (lower cost than the assumed cost of PHS in this report).

5.1 Investment and Dispatch Impacts

5.1.1 Nameplate Capacity of Generation

As described in Section 3.2, adding VG to a power system decreases the amount of new non-VG capacity that is economic to add in 2030 relative to a scenario with no VG capacity. The amount of non-VG capacity that is built in the present framework is based on economic considerations: new generation resources are only added if the short-run profits earned by the resource can cover the annualized investment cost and fixed O&M cost. The resulting investments, however, are coupled with indicators of the reliability of the system. Across all of the penetration scenarios and VG technologies, for example, the percentage of time with wholesale power prices that equal or exceed $500/MWh[39] is always below 1% of the year, Table 1.[40] If too little generation were built to cover peak demand and AS in cases with high penetration of VG then the percentage of time with price spikes would increase and, as illustrated earlier in Figure 2, the short-run profits of conventional generation would increase. The fact that the amount of time with price spikes stays relatively constant with increasing VG, suggests that just as sufficient generation capacity is being added in the case without VG as is being added in the cases with increasing VG penetration.[41]

[38]We were not exactly attempting to match AS requirements for the WECC region. To be in compliance with current WECC requirements, the spinning reserves would need to be equivalent to half of the total contingency reserves. This would imply that the spinning reserve would be increased to 3% of the load and the non-spinning reserve would be decreased to 3%. Since these requirements do not change with changes in the penetration of variable generation, this change in contingency reserve allocation would not be expected to have a noticeable impact on the marginal economic value of variable generation.

[39]$500/MWh is the lowest scarcity price level that indicates that AS targets are not being met.

[40]The percentage of time that wholesale prices equal or exceed $500/MWh is based on load and generation data from only one year. In a reliability focused planning study where it is important to ensure an absolute level of reliability (rather than maintaining a relative level of reliability in this study) it would be important to include more years of data with different load and generation shapes. In addition, factors like scheduled maintenance and forced outage rates would need to be considered. These issues are less important for this study since the results are driven primarily by maintaining a relative level of reliability rather than reaching an absolute reliability target.

[41]Following the arguments in Appendix F, a relatively constant number of hours with scarcity prices across the year, as expected for a system that maintains a long-run equilibrium, is an indicator that a reliability-based loss of load expectation analysis (LOLE) would similarly find a constant LOLE across the scenarios (other than the high CSP_6 cases).

Text Box 2. Comparison of variable generation to flat block of power

Irrespective of the generation profile, adding significant amounts of any type of new generation to a power system to some degree changes dispatch and investment decisions in the rest of the power system. A case was run using a resource that has a flat generation profile over the entire year in order to better highlight changes in the marginal economic value of variable generation that are due in part to factors like temporal generation profiles, variability, and uncertainty in contrast to changes that are associated with simply adding significant amounts of generation from a new resource. This resource is referred to as a flat block throughout the Results section. The flat block is only meant to provide an idealized comparison; it is not meant to characterize any particular alternative resource.

The total nameplate capacity and the total annual energy production from the resources in the power market with increasing penetration of a flat block are shown in Figure 3. From 0% to 30% penetration adding a unit of nameplate capacity from the flat block offsets the need to build new combined cycle natural gas plants. At 40% penetration of a flat block, however, no new combined cycle plants need to be built and none of the existing thermal generation finds it economically attractive to retire for economic reasons. At this penetration, then, the total nameplate capacity slightly exceeds the total nameplate capacity between 0% to 30% penetration of the flat block.

Increasing penetration of the flat block offsets energy generated by combined cycle natural gas plants. Even at high penetration adding power from a flat block does not displace any generation from the small amount of incumbent coal in this market in 2030.

Additional results based on increasing the penetration of a flat block are included throughout the Results section along with comparable results for the four variable generation technologies.

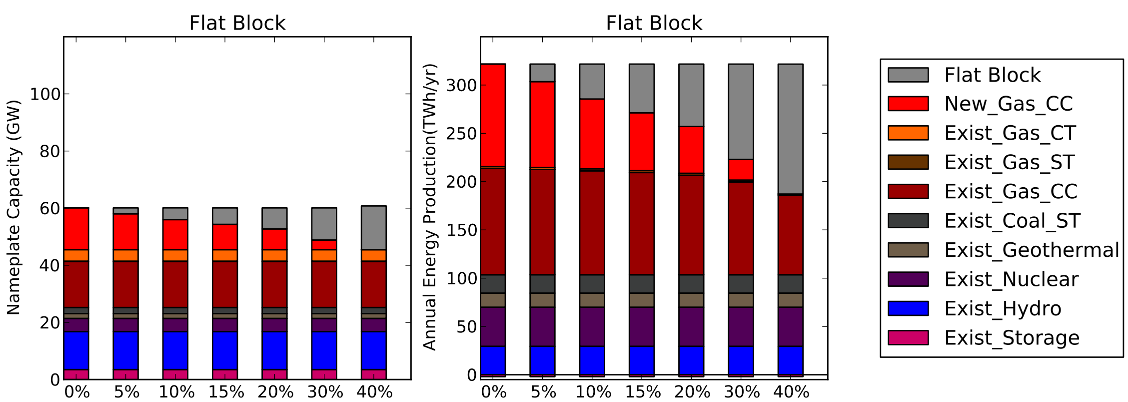


Figure 3: Total nameplate capacity and total energy generation from different resources with increasing penetration of a flat block of power.

Interestingly, the frequency of price spikes decreases with very high penetrations of CSP_6 presumably because the overall system shifts towards being energy constrained rather than capacity constrained as is explained throughout the Results section.

Table 1: Percentage of the year with energy prices that equal or exceed $500/MWh with increasing penetration of VG.

	Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	0.8%	n/a	0.8%	0.8%	0.8%	0.8%	0.8%	0.7%
Wind	0.8%	n/a	0.7%	0.7%	0.7%	0.8%	0.8%	0.8%
PV	0.8%	0.8%	0.8%	0.8%	0.8%	0.7%	0.7%	n/a
CSP0	0.8%	0.8%	0.8%	0.8%	0.7%	0.6%	0.6%	n/a
CSP6	0.8%	0.8%	0.7%	0.6%	0.6%	0.3%	0.0%	n/a

Additionally, the amount of involuntary load shedding as a percentage of the total load remains below 0.01% with increasing penetration of VG, Table 2. If too little generation were built or if the system did not have sufficient flexibility to manage higher penetrations of VG then the amount of involuntary load shedding would substantially increase. That the amount of involuntary load shedding remains below 0.01% even with high VG penetration also demonstrates that sufficient generation is being built by the model and that the system has sufficient flexibility to manage VG. The amount that the involuntary load shedding does increase in cases with high VG penetration, particularly high wind, can be explained in part due to the steeper net-load duration curve at the very high net-load levels with high VG penetration relative to the steepness of the load duration curve at very high load levels without VG. When the cost of new capacity is roughly $200/kW-yr and the value of lost load is assumed to be $10,000/MWh, it is more economic to involuntarily shed load for any net-load level that occurs less than roughly 20 hours per year than it is to build new capacity just to meet those very infrequent high net-load events. Because the net-load duration curve is slightly steeper more of the net-load occurs for less than 20 hours per year than the amount of load that occurs for less than 20 hours per year without VG.[42]

At 40% penetration of a flat block the amount of involuntary load shedding falls because new capacity no longer needs to be built and therefore the periods with prices high enough to trigger involuntary load shedding are not needed to induce new investments. Instead, the prices only need to rise high enough to ensure that incumbent generation does not retire for economic reasons. As with the frequency of high prices, the amount of involuntary load shedding decreases with high CSP_6 penetration as the overall system shifts towards being energy constrained rather than capacity constrained.

The resulting amount of new conventional generation that is built, the amount of incumbent conventional capacity, and the nameplate capacity of VG are shown for each penetration level in Figure 4.

In all cases (excluding the sensitivity cases explored later) the only new non-VG investments are in new CCGT resources under the assumptions used in this study. While the short-run profit of new CCGT resources was approximately equal to the investment cost of new CCGTs, the short-run profits of new coal, new nuclear, and new PHS resources were far below their annualized investment cost, Table 3. Major changes to fuel costs or investment costs would likely be needed to increase investments in these other technologies.

Similarly, no new CTs were built in addition to the existing incumbent CTs. The short-run profit of the CTs however, was commonly close to or above 90% of the annualized fixed investment cost of new CTs, or only $20/kW-yr or less below the assumed annualized investment cost of CTs. Even though the CCGTs were assumed to have fixed investment and O&M costs that were $10/kW-yr more than that of the CTs,

[42]Whereas the number of hours of the year with price spikes in Table 1 is a proxy for the loss of load expectation (LOLE) that would be estimated in a reliability analysis, the percentage of unmet load in Table 2 is a proxy for the expected unserved energy (EUE), a different reliability metric. As a result, these results suggest that even if the LOLE calculated in a reliability study were expected to remain constant across these scenarios, the EUE calculated in a reliability study would be expected to slightly increase with increasing penetration of variable generation.

Table 2: Percentage of the total annual load that is not met during periods with prices that exceed the value of lost load ($10,000/MWh).

	Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	0.004%	n/a	0.004%	0.004%	0.004%	0.004%	0.004%	0.002%
Wind	0.004%	n/a	0.005%	0.004%	0.005%	0.006%	0.008%	0.009%
PV	0.004%	0.002%	0.003%	0.004%	0.006%	0.007%	0.006%	n/a
CSP_0	0.004%	0.002%	0.003%	0.005%	0.006%	0.006%	0.006%	n/a
CSP_6	0.004%	0.004%	0.003%	0.002%	0.001%	0.000%	0.000%	n/a

the CCGTs were slightly more economically attractive because the CCGTs earned greater short-run profit in non-scarcity hours due to their relatively high efficiency in comparison to the CTs (they both earned roughly the same amount during scarcity hours). That being said, CTs become increasingly more attractive with increasing penetration of VG (except in the case of increasing CSP_6) due to the decreased amount of energy needed from CCGTs and the increased value of CT flexibility. Relatively modest reductions in the assumed investment cost of CTs relative to CCGTs would therefore lead to new CTs substituting for a portion of the CCGTs that are built, as is found in the sensitivity studies in Section 5.4.3. Similarly, consideration of factors such as the shorter lead time for construction and smaller size of individual units, factors not considered in this analysis, would tend to favor new CTs instead of new CCGTs. Furthermore, the relatively high amount of flexibility from the incumbent CTs, hydro, and pumped hydro storage in California all contribute significant flexibility to the system that would otherwise require new CTs in regions that lack substantial flexibility in the incumbent generation. Given the relatively small difference in the gap between the short-run profit and fixed cost of CTs relative to the gap for CCGTs it is important that CTs are considered in more detail in studies that would guide actual procurement processes.

Table 3: Short-run profit of investment options as a percentage of annualized fixed cost with and without 20% penetration of VG in 2030.

Investment Option	CCGT	CT	Coal	Nuclear	PHS
Fixed Cost ($/kW-r)	203	194	494	950	706
VG Technology	Short-run Profit as Percentage of Fixed Cost (%)				
0% VG	100%	88%	76%	51%	28%
20% Flat Block	100%	88%	76%	51%	28%
20% Wind	100%	94%	76%	51%	31%
20% PV	100%	95%	76%	51%	34%
20% CSP_0	100%	98%	74%	49%	36%
20% CSP_6	99%	68%	75%	51%	8%

As VG penetration increases, the total nameplate capacity of the combintation non-VG and VG resources increases above the nameplate capacity of non-VG resources alone in the 0% VG case. The increase in total nameplate capacity of the combintation of non-VG and VG resources is particularly evident in the cases with wind, PV, and CSP_0. This reflects the relatively low capacity factor of these resources and their relatively low ability to offset new investments in non-VG capacity especially at high penetration levels. Despite the increase in the combination of VG and non-VG nameplate capacity, in all cases the amount of non-VG capacity alone actually decreases with increasing VG penetration due to reductions in the amount

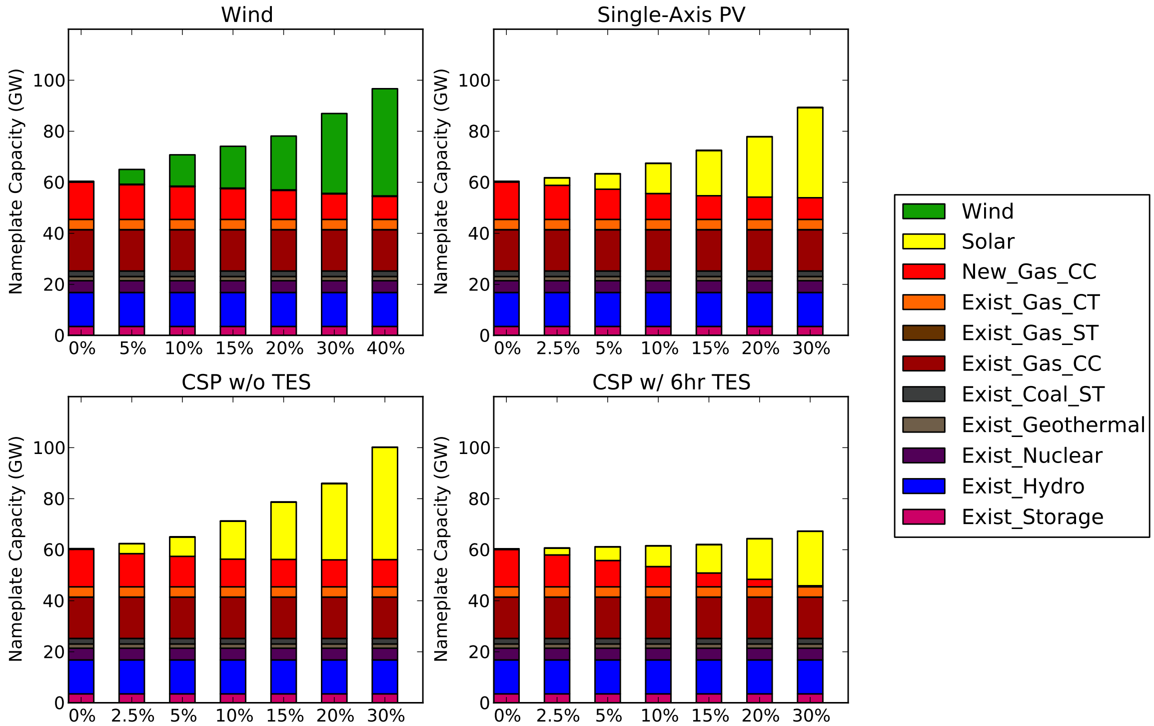


Figure 4: Total nameplate capacity of generation with increasing penetration of variable generation.

of new CCGTs that are built. No penetration levels showed an increase in the nameplate capacity of non-VG capacity relative to the 0% VG case, indicating that VG at all penetration levels had some ability to offset new investments in non-VG capacity. In addition, all incumbent capacity in 2030 that was not retired for technical reasons found it to be economically attractive to stay in the power market in 2030. In other words, the short-run profit of incumbent generation always exceeded the assumed fixed O&M cost required to continue to operate the incumbent resources.

The effectiveness of VG in reducing the amount of non-VG capacity that is needed with increasing penetration differed between technologies. PV and CSP_0 were more effective at reducing the non-VG capacity at low penetration, but lost effectiveness at higher penetration levels. Wind only slightly reduces the amount of non-VG capacity that is built, but wind continues to displace a small amount of non-VG capacity even at higher wind penetrations. CSP_6 was very effective at reducing non-VG capacity at both high and low penetration levels.

The effectiveness of VG in reducing the amount of new non-VG nameplate capacity that is built can be more easily observed through calculating the implied marginal capacity credit of VG. As described in Section 3.3, the implied marginal capacity credit (hereafter called the capacity credit) is calculated as the incremental reduction in non-VG nameplate capacity per unit of additional VG nameplate capacity added between two different penetration levels. The capacity credit between two low penetration cases (0% and 5% penetration) and between two high penetration cases (15% and 20% penetration) is shown in Table 4. The increase in total (VG and non-VG) nameplate capacity with increasing penetration for each VG technology shown in Figure 4 can be explained by the fact that the capacity credit of the VG resources is in most cases far below 100% of the nameplate capacity and is therefore also far below the capacity credit of new CCGT resources or of a flat block of power. Since the capacity credit of VG is less than the capacity credit of new

CCGT resources that are used to meet system needs in the 0% VG case, the total nameplate capacity of all generation increases.

There are also important differences between the various VG technologies in terms of their capacity credit. At low penetration, the capacity credit of the solar technologies is highest. This high capacity credit is due to the coincidence of solar production and scarcity prices, which at low penetration occur during times with peak demand. The capacity credit of PV and CSP_0 calculated in this model is within a similar range estimated for low penetrations of solar using more detailed probabilistic methods (Shiu et al., 2006; Pelland and Abboud, 2008; Madaeni et al., 2012b).[43] The ability of TES to shift production from mid-day into the later afternoon hours results in a significantly higher capacity credit for CSP_6 relative to CSP_0 and PV. The coincidence of wind production and scarcity prices is lower, which leads to a lower capacity credit for wind.

At high penetration, the capacity credit of PV and CSP_0 drop by a considerable amount while the capacity credit of wind only decreases by a small amount from its already low level. In fact, the marginal capacity credit of wind at high penetration is slightly greater than the capacity credit of PV and CSP_0 at high penetration. The steep decline in the capacity credit of PV and CSP_0 indicates that the addition of more PV or CSP_0 when the penetration of those technologies is already high does not offset as much conventional capacity as they did at low penetration levels. Intuitively, this is because with high PV and CSP_0 penetration the net load peaks during early evening hours, and no increase in PV or CSP_0 capacity can help meet demand during that time. More specifically, as will be described in Section 5.2, the decreasing capacity credit of these solar technologies is a result of prices decreasing during times with higher solar production (i.e. scarcity prices stop occurring in the afternoon on summer days) and scarcity prices shifting to early evening hours in the summer when there is little or no solar production from PV and CSP_0 yet demand is still high. The decreased capacity credit for PV or CSP_0 with increasing penetration has been noted before (Kahn, 1979; Perez et al., 2008).

With thermal storage, however, the TES is dispatched such that a CSP_6 resource continues to produce power into the early evening and even later evening hours until the normal diurnal demand is considerably lower. The capacity credit of CSP_6 is therefore relatively high both at low penetration and high penetration.

5.1.2 Energy Production

Irrespective of the ability of VG to reduce the amount of conventional capacity that is built in future years, it is clear that all VG resources reduce the amount of electricity that is generated by conventional generation. Similar to the impact of adding a flat block of power, generation from natural gas fired CCGTs is found to be particularly affected with increasing penetration of VG as shown in Figure 5. The slight increase in total energy production with increasing VG penetration in Figure 5, as opposed to constant energy production across all scenarios, is due to the energy that is available from VG but is curtailed. Curtailment is examined in more detail later in this section.

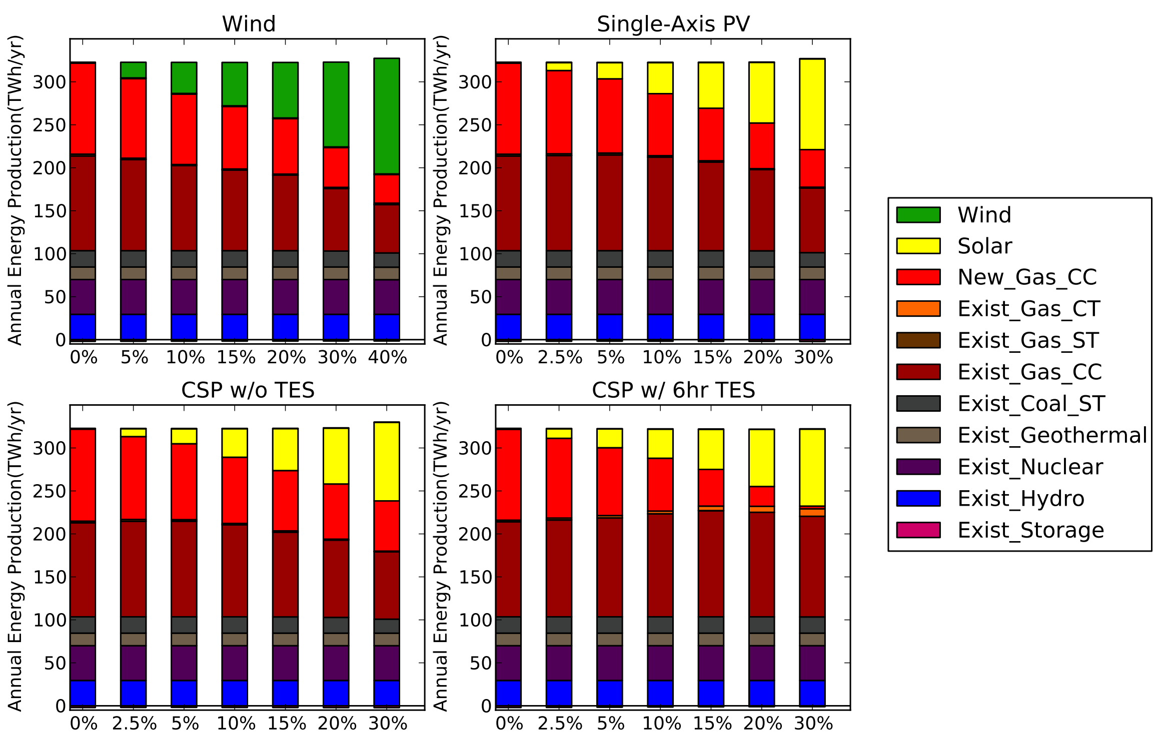
The amount of energy from incumbent CT resources remains a small fraction of total generation. Only in the high penetration cases with CSP_6 does the generation from CT resources increase a noticeable amount.

Further investigation shows that the increase in energy from CT resources in high CSP_6 penetration scenarios is due to a lack of sufficient energy generation in winter months. One interesting trend noted earlier in Table 1 is that power prices are less likely to rise to high levels in the cases with increasing penetration of CSP_6. This lack of high price periods coupled with new generation investment in CCGT

[43] It is not clear exactly why the effective incremental capacity credit of single-axis tracking PV is slightly greater than the capacity credit of CSP_0. The result appears to be very sensitive to the generation profile at the end of the day. In some days with price spikes PV generated slightly more energy per unit of nameplate capacity in early evening hours relative to CSP_0 at low penetration levels, which would contribute to a slightly larger capacity credit for PV relative to CSP_0. This finding is not only due to the assumed latitude tilt of the single-axis tracking PV because similar differences in the generation profile in the few days with price spikes were observed at low penetration using a PV generation profile based on single-axis tracking PV that was not tilted at the latitude of the PV site. One potential reason for the small difference in capacity credit is due to the minimum generation constraint on CSP_0 of 25% of the nameplate capacity which would potentially cause CSP_0 to generate less energy in the early evening hours relative to a PV plant without a similar minimum generation constraint. Nevertheless it is clear that the relatively small differences in the capacity credit are extremely sensitive to early evening generation profiles and further detailed analysis of the capacity credit would be needed to determine if there is a significant difference between the capacity credit of single-axis tracking PV and CSP_0.

Table 4: Effective incremental capacity credit of VG at low and high penetration levels.

	Low Penetration of VG 0% → 5%			High Penetration of VG 15% → 20%		
Technology	Incremental Reduction in Non-VG Capacity (GW)	Incremental Increase in VG Capacity (GW)	Effective Marginal Capacity Credit	Incremental Reduction in Non-VG Capacity (GW)	Incremental Increase in VG Capacity (GW)	Effective Marginal Capacity Credit
Flat Block	2.1	2.1	100%	1.6	1.6	100%
Wind	1.0	5.7	18%	0.7	4.7	15%
PV	2.8	5.8	48%	0.4	5.9	7%
CSP_0	2.7	7.3	37%	0.2	7.4	2%
CSP_6	4.3	5.1	84%	2.5	4.8	52%



Note: Energy for existing storage (Exist_Storage) is a negative value that represents the net energy consumed by pumped hydro storage.

Figure 5: Total energy generation from different resources with increasing penetration of variable generation in 2030.

resources and an increase in CT production indicates that the system is increasingly “energy-constrained” rather than “capacity-constrained” in these scenarios. In these high CSP_6 cases, new CCGT resources are built, in part, to provide energy in winter months. In December, in particular, sufficient capacity is available to meet demand between the capacity of the thermal plants, hydropower generation, storage, and CSP_6 resources. However, in order to meet demand, during this month the capacity factor of CT resources rises to 98% when in a case with no VG the CTs would normally be off for the entire month. While the thermal generation is dispatched near to its maximum capacity for the month of December, the amount of energy that can be produced over the month by hydropower and the amount of energy that can be produced by CSP_6 resources is limited due to resource constraints (limited water supply for the hydro resources and extended cloudy periods for the CSP_6). The addition of new CCGT plants provides additional energy in December in addition to capacity in other high load months.

The incumbent PHS is represented as a net consumer of energy on the system in Figure 5 because storage consumes more electricity during the storage cycle than it can discharge during the generation cycle. The net energy consumption of storage is very small, usually less than 2 TWh/yr, and does not change noticeably between the high and low penetration cases for most VG technologies. With high penetrations of CSP_6 the net energy consumption of PHS decreases. The decrease indicates that incumbent PHS is used less frequently in the high CSP_6 cases than it is used in cases without VG. This is presumably because the system has access to considerable amounts of TES and arbitrage opportunities between low and high price periods are less prevalent.

At high penetration levels a small amount of incumbent coal generation is also displaced by VG. Since the variable cost of coal is much lower than the variable cost of CCGT resources, natural gas plants will generally be dispatched to their lower limits before coal plants are dispatched down. The slight reduction in energy generation from incumbent coal plants indicates that coal plants will be the marginal plant more often in cases with high VG than in cases without VG. In regions of the country with more incumbent coal than California the displacement of coal is expected to occur at a lower penetration of VG than observed in this case study.

Even before displacing energy from coal plants, however, cases with VG increasingly decrease the energy production from natural gas CCGTs. The ratio of the energy produced by incumbent natural gas CCGTs to the energy that could be produced if the CCGT were at full output all year, also known as the CCGT capacity factor, decreases with increasing penetration of VG, Table 5. Even increasing the penetration of a flat block of power, however, causes incumbent CCGTs to have a lower capacity factor. The increased energy available from the flat block of power effectively pushes the supply curve out, increasing the frequency by which incumbent CCGTs are marginal generation resources, at minimum generation, or offline.[44] Relative to the impact of a flat block, adding wind, PV, or CSP_0 further decreases the capacity factor of incumbent CCGTs with increasing penetration. The capacity factor of incumbent CCGTs increases with increasing CSP_6 relative to the same amount of energy with a flat block of power.

Though the capacity factor of incumbent CCGTs decreases substantially with increasing penetration of most VG technologies, the load factor of the CCGTs does not necessarily decrease at the same rate with increasing VG penetration. The load factor for a CCGT vintage is the energy-weighted average of the ratio of the actual generation from the CCGT vintage relative to the amount of the CCGT vintage that was on-line. The load factor in a particular hour where the new CCGT vintage was generating at 800 MW when 1000 MW of the new CCGT vintage was online would be 80%. Since CCGT plants are most efficient when operated at their full capacity, the most efficient dispatch, assuming there were no AS requirements, no forecast errors and no start-up costs, would always ensure that the amount of on-line generation exactly matched the amount of energy that would be needed from the generation vintage in each hour. The new CCGT vintage would therefore only have 800 MW online when it was generating at 800 MW, such that the load factor was 100% (i.e., at full-load).

Constantly matching the amount of power generated by the vintage to the amount of the vintage that

[44]This reduction in capacity factors for incumbent resources with increasing penetration of a flat block of power is similar to the observation by Milligan et al. (2011) that increasing penetrations of a flat block could lead to increased cycling of incumbent coal plants.

Table 5: Capacity factor of mid-size incumbent CCGT resources with increasing penetration of VG in 2030.

	Capacity Factor (%) Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	81%	n/a	80%	79%	77%	75%	69%	58%
Wind	81%	n/a	78%	72%	68%	63%	52%	40%
PV	81%	82%	82%	80%	76%	70%	59%	n/a
CSP0	80%	82%	82%	79%	74%	68%	61%	n/a
CSP6	81%	83%	85%	89%	91%	89%	85%	n/a

is online would require frequent start-ups and shutdowns of the generation resources. The dispatch model used in this report is formulated to account for AS requirements, DA forecast errors and start-up costs which means the load factor can and will be less than 100% (i.e., part-loaded) in any hour. The load factor of a vintage is less than 100% in some hours due to some combination of (1) contributions toward meeting the AS targets, (2) redispatch to manage forecast errors between the DA and RT and (3) avoiding start-up costs associated with bringing CCGT capacity on-line. The latter factor can also decrease the load factor of CCGTs in a case with an increasing penetration of a flat block of power. Hence, cases with high VG penetration and even the case with high penetrations of a flat block of power increasingly require natural gas CCGTs to be operated at part-load. Increased operation at part-load will decrease the overall efficiency of CCGT plants.[45]

The decrease in efficiency at part-load means that the actual reduction in fuel consumption and emissions measured by the dispatch model is less than the reduction that would be expected if the efficiency of CCGTs remained at the full-load efficiency level even while part-loaded. The increase in part-loading of CCGT plants is quantified by examining the load factor of CCGT resources with increasing penetration in Table 6.

Table 6: Energy-weighted average load factor of mid-size incumbent CCGT resources with increasing penetration of VG in 2030.

	Load Factor (%) Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	97%	n/a	96%	96%	96%	95%	94%	93%
Wind	97%	n/a	96%	95%	94%	93%	92%	91%
PV	97%	97%	98%	97%	94%	91%	91%	n/a
CSP_0	96%	97%	98%	97%	94%	93%	92%	n/a
CSP_6	97%	98%	98%	99%	99%	99%	98%	n/a

The results in Table 6 indicate that mid-size incumbent CCGT resources operate at part-load (a load factor less than 100%) more frequently with high penetration of a flat block, but even more so with high VG penetration, except with CSP_6 where the TES helps the mid-size incumbent CCGT be dispatched more efficiently. Even with high VG penetration, however, the load factor remains above 90%. A mitigating factor that helps keep the load factor from dropping too low with VG penetration, even though the capacity factor of the same vintage drops at a much faster rate, is the ability to shut-down CCGT resources during low load or high VG generation periods rather than always part-loading the resource. The tradeoff is the increase in start-up costs to bring the generation offline and then back online at a later point.

[45] The heat rate curves and the no-load heat rate for each vintage are described in more detail in Appendix D.

Table 7: Average heat rate of mid-size incumbent CCGT resources with increasing penetration of VG in 2030.

	Average Heat Rate (MMBTU/MWh) Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	7.2	n/a	7.2	7.2	7.2	7.2	7.3	7.3
Wind	7.2	n/a	7.2	7.2	7.3	7.3	7.3	7.4
PV	7.2	7.2	7.2	7.2	7.3	7.4	7.6	n/a
CSP_0	7.2	7.2	7.2	7.2	7.3	7.4	7.5	n/a
CSP_6	7.2	7.2	7.2	7.2	7.2	7.2	7.2	n/a

Increased part-load operation, more frequent start ups, and increased provision of reserves from on-line resources will reduce the overall average efficiency of thermal plants in converting fuel into electricity. The reduction in efficiency can be observed through an increase in the ratio of annual fuel consumption to annual energy production, or the average heat rate of a resource. The average heat rate of a particular vintage of thermal generation, incumbent mid sized CCGT resources, is shown to slightly increase with increasing penetration of a flat block and increase even more with increasing penetration of VG in Table 7, with CSP_6 again being an exception due to the thermal energy storage. For the other VG technologies, this reduction in efficiency of thermal generation also leads to a reduction in the avoided emissions from adding VG than otherwise would be the case were efficiency degradation not to occur.

5.1.3 Avoided Emissions

A byproduct of the investment and dispatch decisions is the pollution emissions from the thermal generation with increasing penetration of VG.[46] Since the addition of VG is found to primarily displace electricity generated by incumbent and new natural gas fired CCGT plants in the cases evaluated here, the reduction in emissions relative to a case without VG are also primarily from avoiding emissions from CCGT resources. The avoided CO_2 emissions are proportional to the avoided fuel combustion in thermal resources. The avoided NO_x and SO_2 emissions, however, are not proportional to fuel consumption due to emissions during start-up and part-load that are greater than would be expected based on the fuel burned during those times. NO_x emissions during start-up and part-load operation are reported to be particularly high (Denny and O'Malley, 2006; Katzenstein and Apt, 2009; Suess et al., 2009).

The formulation of the dispatch model, described in Section 3.1, accounts for the increase in emissions during start-up and due to part loading of thermal plants, though the same caveats regarding the simplification of the commitment and dispatch based on vintages applies equally to estimating the avoided emissions. The total emissions of CO_2, NO_x, and SO_2 all decrease with increasing VG penetration relative to the case with 0% VG penetration, Figures 6–8. The decrease in emissions with increasing penetration of all VG indicates that the start-up and part-load emission impacts are secondary to the overall reduction in electricity production from thermal generation, the main driver of the decrease in emissions. CO_2 emissions decline with increasing VG penetration to a greater degree in percentage terms than NO_x and SO_2 because NO_x and SO_2 are found to be dominated by the relatively small amount of incumbent coal resources that are not, until very high penetration, displaced by VG.

At very high penetration (greater than 20% penetration) VG begins to reduce the energy generated from incumbent coal resources. The emissions from incumbent coal resources are higher per unit of electricity than

[46] Similar to the decision to not model regulations and policies like the California RPS, we do not include any existing emissions related policies that would impact the cost and quantity of power plant emissions in California, such as a SO_2 cap-and-trade program. Actual emissions will be impacted by technology characteristics (which are modeled in this report) as well as regulations (which are not considered here). Moreover, NO_x and SO_2 are regional pollutants where the damage of the pollutant depends on factors including where pollution is emitted from, when the pollutant is emitted, and prevailing weather conditions, not just the quantity of pollutant emitted. These factors are not considered in this analysis.

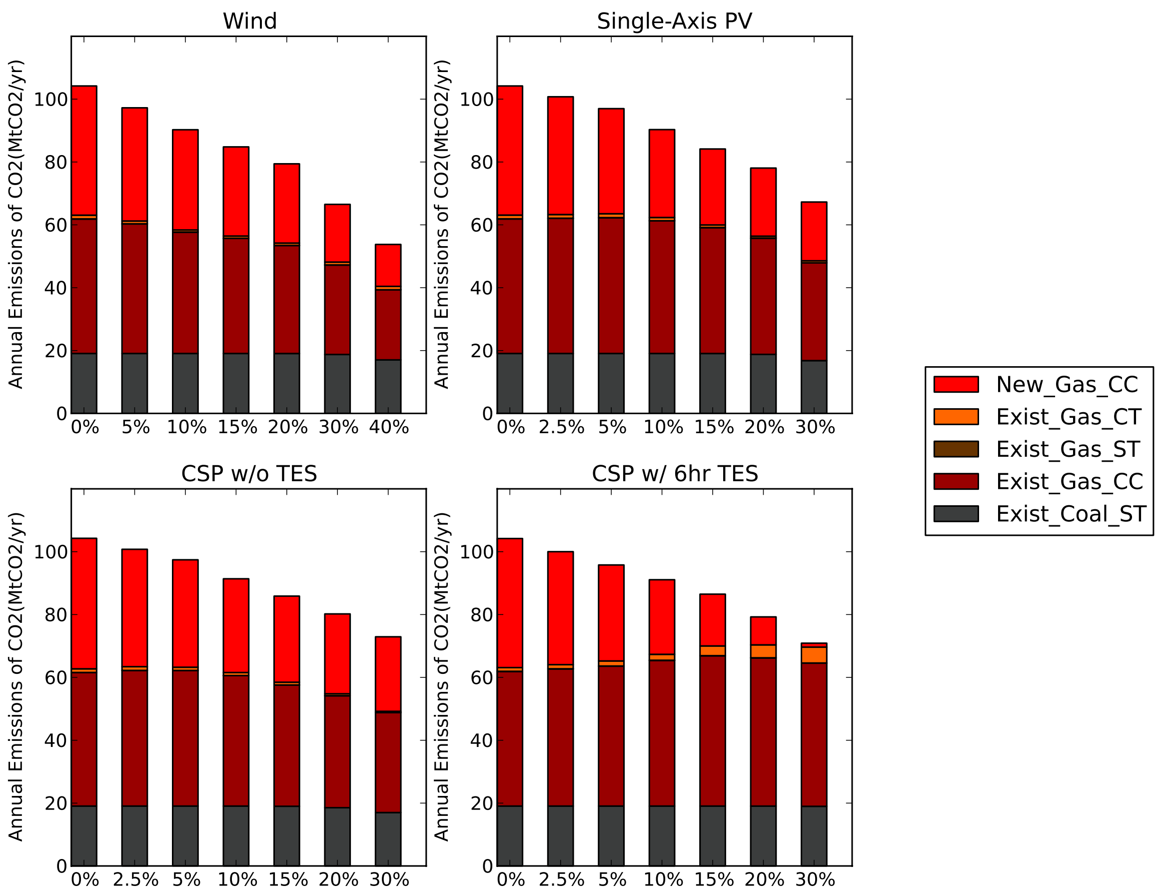


Figure 6: Total CO_2 emissions from different resources with increasing penetration of variable generation in 2030.

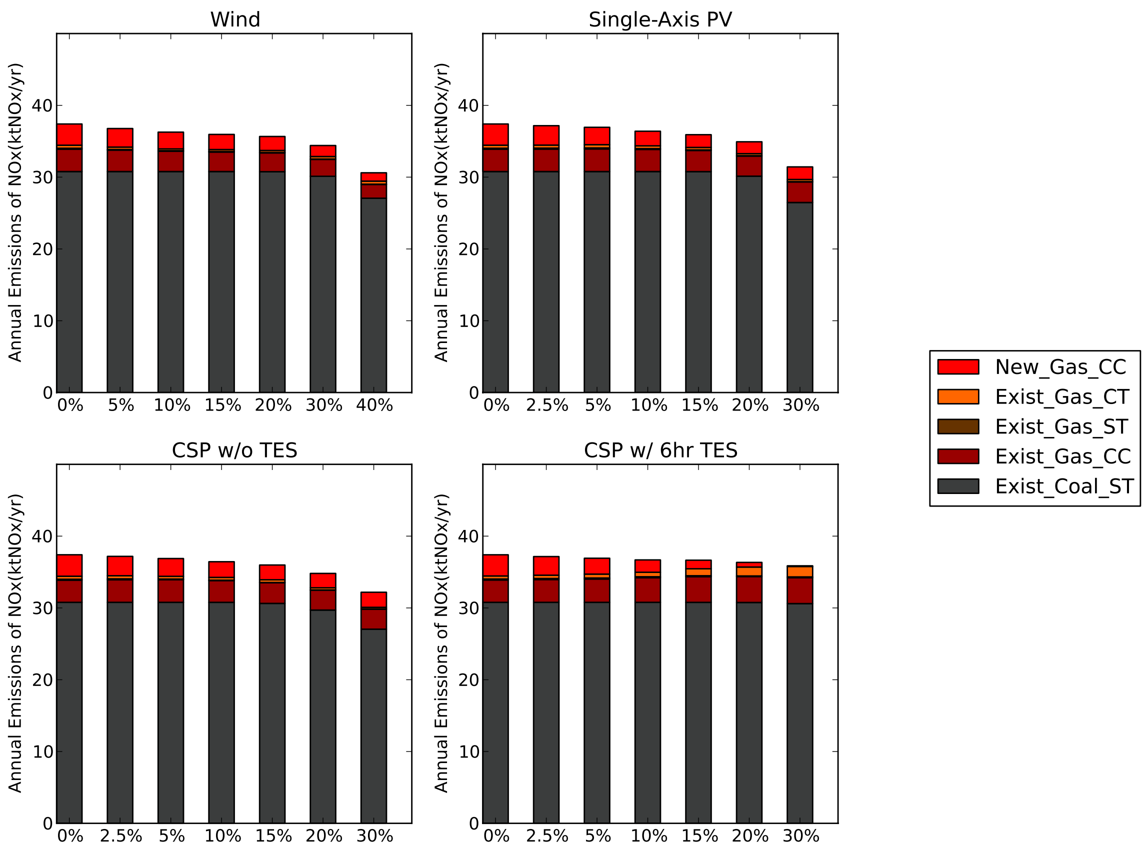


Figure 7: Total NO_x emissions from different resources with increasing penetration of variable generation in 2030.

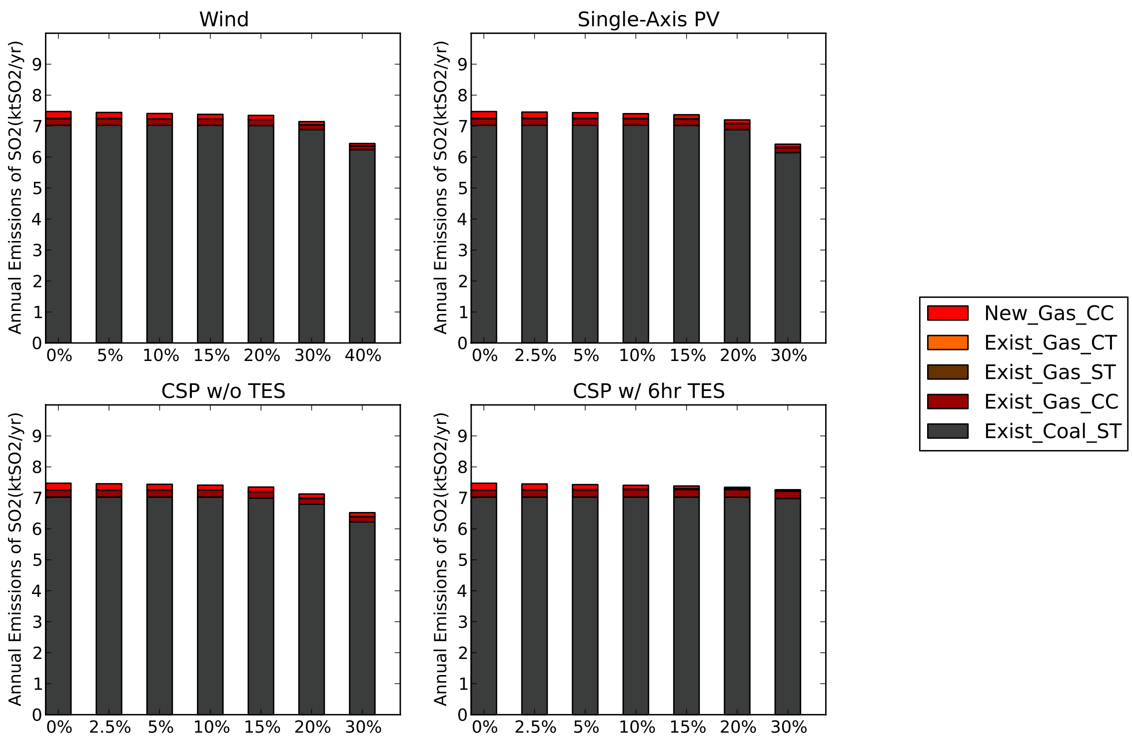


Figure 8: Total SO_2 emissions from different resources with increasing penetration of variable generation in 2030.

the emissions from natural gas resources, with over two orders of magnitude difference in the emissions rate per unit of electricity in the case of SO_2. The reduction of electricity from coal resources at high penetration overwhelms any effects due to start-up and part-loading of natural gas resources for NO_x and SO_2 emissions. Though this is less evident for CSP_6, the overall impact of very high VG penetration, therefore, is to displace more emissions per unit of electricity from VG than at low penetration, at least under the assumptions used in the present analysis. The penetration level at which VG start to displace incumbent coal is of course dependent on the amount of incumbent coal capacity in the region. Regions with more incumbent coal will experience reductions in coal plant output and emissions at lower VG penetration levels than found here.

Another way to examine the avoided emissions from adding VG is to show the ratio of the incremental reduction in emissions between two cases and the incremental increase in VG generation between those two cases. This incremental avoided emissions rate is shown for CO_2 in Table 8, NO_x in Table 9, and SO_2 in Table 10. The avoided emissions rate is similar to the rate of emissions of a fully-loaded CCGT plant at high and low penetration levels (385 kg CO_2/MWh, 28 g NO_x/MWh, and 2 g SO_2/MWh for a mid-sized incumbent CCGT), except when VG starts displacing generation from coal resources. The reduction in efficiency due to part-loading and start-up of thermal generation ends up leading to a small reduction in the overall incremental avoided CO_2 emissions rate at high penetration relative to the incremental avoided CO_2 emissions rate at low penetration, as shown in Table 8, particularly for PV and CSP_0. The somewhat greater degradation in CO_2 emissions benefits for PV and CSP_0 are presumably caused by the relatively higher part loading and start up required to manage these resources relative to wind and CSP_6. On the other hand, Table 9 shows a reduction in the incremental avoided NO_x emissions rate for wind and CSP_6 when comparing 0-5% penetration to 15–20% penetration at the same time that the incremental avoided NO_x emissions rate for PV and CSP_0 increases. The incremental avoided SO_2 emission rate also increases for PV and CSP_0, Table 10. The increase in the incremental avoided NO_x and SO_2 emissions rate for PV and CSP_0 is due to the small displacement of coal between 15–20%. When VG displaces generation from incumbent coal, as is the case with high PV and CSP_0 penetration, the incremental avoided emissions from VG increase since coal produces significantly higher emissions (for NO_x, and SO_2) than CCGT resources. While coal also produces higher CO_2 emissions per unit of electricity, the difference between the emissions rate of coal and natural gas is not as high as it is for NO_x and SO_2. As can be seen in Figures 7 and 8, the incremental avoided NO_x and SO_2 emissions rate for wind also begins to climb at very high penetration levels as wind displaces incumbent coal.

These avoided emissions results are dependent on the particular mix of generation and assumptions regarding retirement. In particular, regions with more incumbent coal than California would have emissions from coal plants displaced by VG at lower penetration levels than found in this case study. Nonetheless, the main conclusion from these results is that adding VG avoids emissions, even when part-load and start up emissions are accounted for. The magnitude of avoided emissions depends on the mix of generation (including retirements), the type of generation that will be built in future years, and the generation profile of VG.

5.1.4 Curtailment

At higher penetration levels, VG will sometimes produce power when the system has limited flexibility to manage the additional VG (i.e., the system has limited ability to reduce the output of other generation), as described earlier in Section 3.1.5. During these hours the wholesale price for electricity will decrease to very low levels (approaching \$0/MWh) which may make VG indifferent to curtailing (and earning no revenue) or generating (and earning almost no revenue). When even more VG is available during these constrained times curtailment of VG will be required. In contrast to VG, curtailment did not occur for increasing penetrations of the flat block of power.

The challenges of accommodating higher penetrations of VG can therefore be illustrated in two ways: (1) by examining the amount of VG that is sold at low prices and (2) by examining the amount of VG that has to be curtailed, Figure 9. The amount of energy that is sold at low prices is based on summing the amount of VG scheduled in the DA that occurs when the DA price is below \$1/MWh with the amount of RT deviations from the DA schedule that is sold when the RT price is below \$1/MWh. The amount of curtailment is based

Table 8: Incremental avoided CO_2 emissions rate of VG at low and high penetration level in 2030.

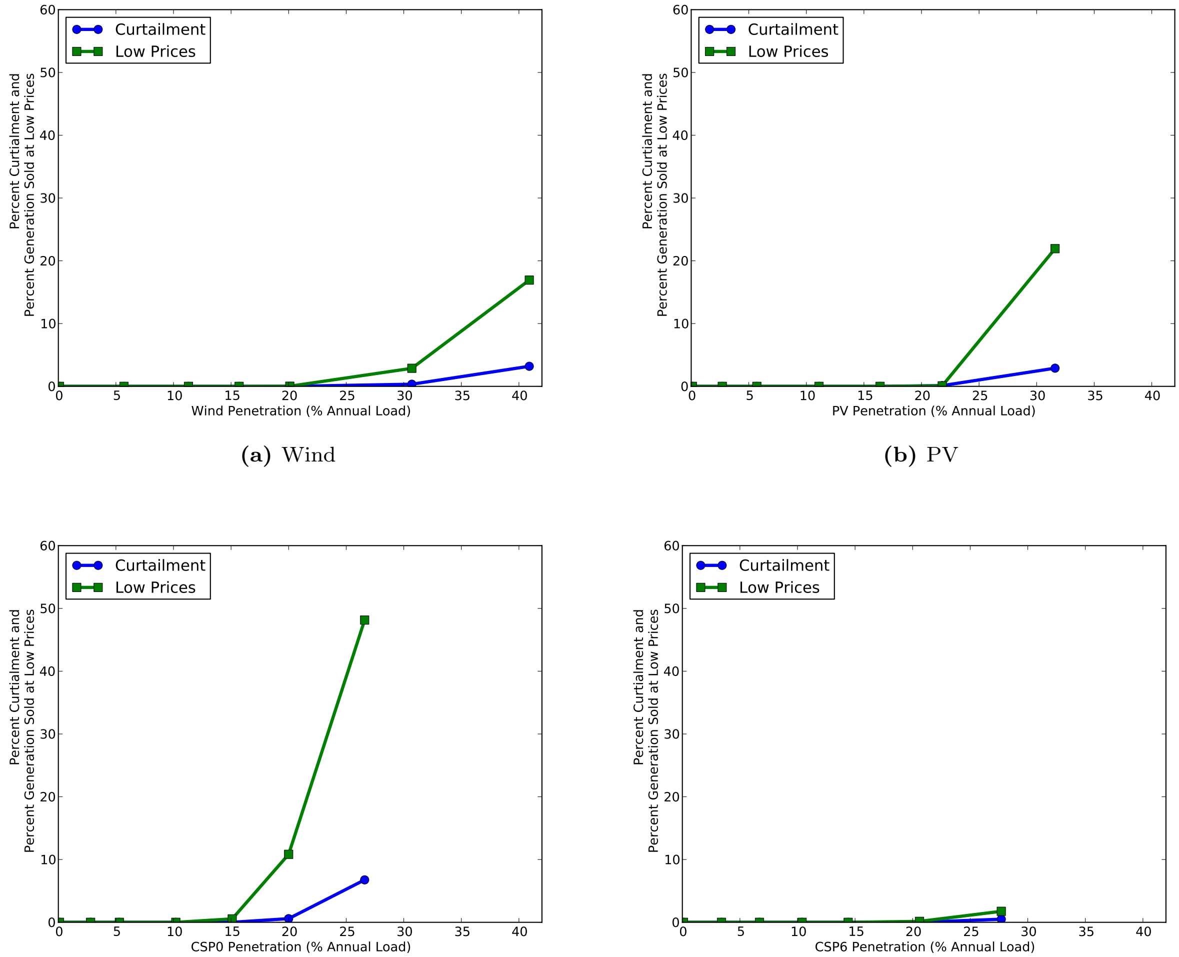
Technology	Low Penetration of VG 0% → 5%			High Penetration of VG 15% → 20%		
	Incremental Reduction in CO_2 Emissions (10^9 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (kg/MWh)	Incremental Reduction in CO_2 Emissions (10^9 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (kg/MWh)
Flat Block	7.0	18	390	5.5	14	390
Wind	7.0	18	390	5.4	14	380
PV	7.2	18	400	6.1	17	350
CSP_0	6.8	17	410	5.7	16	350
CSP_6	8.4	21	400	7.2	20	370

Table 9: Incremental avoided NO_x emissions rate of VG at low and high penetration level in 2030.

Technology	Low Penetration of VG 0% → 5%			High Penetration of VG 15% → 20%		
	Incremental Reduction in NO_x Emissions (10^3 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (g/MWh)	Incremental Reduction in NO_x Emissions (10^3 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (g/MWh)
Flat Block	510	18	28	380	14	27
Wind	630	18	35	290	14	20
PV	460	18	26	990	17	57
CSP_0	520	17	31	1,170	16	72
CSP_6	480	21	23	310	20	16

Table 10: Incremental avoided SO_2 emissions rate of VG at low and high penetration level in 2030.

Technology	Low Penetration of VG 0% → 5%			High Penetration of VG 15% → 20%		
	Incremental Reduction in SO_2 Emissions (10^3 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (g/MWh)	Incremental Reduction in SO_2 Emissions (10^3 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (g/MWh)
Flat Block	35	18	1.9	27	14	1.9
Wind	30	18	1.7	34	14	2.4
PV	37	18	2.1	170	17	9.6
CSP_0	34	17	2.1	220	16	14
CSP_6	44	21	2.1	41	20	2.1



(a) Wind

(b) PV

(c) CSP_0

(d) CSP_6

Figure 9: Curtailment of variable generation and percentage of variable generation that is sold during periods where wholesale power prices are very low (<$1/MWh) in 2030.

on the difference between the amount of energy that is used in the market relative to what could have been used if there were no curtailment. Note that CSP resources have solar fields that are sized larger than the power block (i.e., a solar field multiplier that is greater than 1) in this model. The curtailment that is due to this oversizing was excluded from the curtailment reported here by only focusing on curtailment of CSP that occurs during periods with very low prices (<$1/MWh). This curtailment reflects power system flexibility constraints rather than factors related to the design of CSP plant for cost minimization.

The amount of energy that is sold at low prices increases at a much faster rate with increasing penetration than the amount of VG curtailment. The reason is that when curtailment occurs, only the fraction of the VG generation that exceeds what the system can economically accommodate is curtailed whereas all of the DA scheduled energy is sold at low prices when the DA prices are low. For example, if in a particular hour the DA forecast of VG was 1000 MW but the system could only economically accommodate 950 MW of VG in the DA scheduling process, then 50 MW of VG generation would be curtailed but the remaining 950 MW of generation would be sold at a price of $0/MWh.

Changes in curtailment and the amount of energy sold at low prices with increasing penetration differ substantially across VG technologies. For wind and CSP_6, the amount of energy that is curtailed in the 30% penetration case is less than 1% of the annual available energy. At 40% penetration of wind, curtailment is around 2.5%. At 30% and 40% penetration of wind the amount of energy that is sold at low prices is around 3% and 18% of the annual available wind, respectively. For CSP_6, thermal energy storage helps reduce the amount of energy sold at low prices, less than 2% at 30% penetration. PV and CSP_0 experience substantially greater curtailment and amount of energy sold during low price periods than do CSP_6 and wind, especially at penetrations above 15–20%. The curtailment and amount of energy sold at low prices for CSP_0 at 30% penetration, for example, is 7% and 48%, respectively, more than double the curtailment and amount of energy sold at low prices for wind at 40% penetration. The curtailment and amount of energy sold at low prices for PV follows a similar path as CSP_0. Though not shown here, incremental curtailment rates (incremental curtailment per unit of incremental VG energy) when increasing penetration from 20% penetration to 30% penetration are much higher than average curtailment rates (total curtailment per unit of total VG energy). In the case of CSP_0 the incremental curtailment rate between 20% and 30% penetration is approximately 22%.

The curtailment and amount of energy sold at low prices has an impact on the marginal economic value of VG at high penetration, impacting PV and CSP_0 to a greater extent than wind and CSP_6 (see Sections 5.2 and 5.3). Curtailment was highlighted by Denholm and Margolis (2007) as a potential limit to PV penetration. This report adds further insight by highlighting the portion of VG that is sold at low prices. The curtailment of VG is relatively low compared to other studies and the current curtailment that is observed for wind at relatively low penetration rates for three reasons. First, California is a relatively flexible system with significant hydro resources and substantial gas-fired generation. Analysis of curtailment with increasing PV penetration by Denholm and Margolis (2007) highlighted the important role of the overall system flexibility in mitigating PV curtailment at increasing penetration levels. Second, in long-run equilibrium in 2030 no plants with high fixed costs and low variable costs, such as nuclear generation, are found to be built. If these plants were built the total amount of inflexible baseload generation would increase and curtailment of variable generation would similarly increase. Third, this analysis does not consider curtailment due to insufficient transmission capacity. As mentioned in Section 3.1.5, curtailment due to insufficient transmission capacity between generation and loads is one of the largest contributors to wind curtailment that is currently occurring in the U.S.

5.2 Marginal Economic Value

The preceding dispatch and investment results point to a number of important differences between VG technologies and highlight the impact of increasing VG penetration. At low penetration, solar has a much greater capacity credit than wind. Both wind and solar primarily displace electricity, fuel, and emissions from natural gas CCGT resources at low penetration, under the assumptions used in this report. At high penetration, the marginal capacity credit of wind declines but neither the capacity credit nor the resources that are being displaced by wind generation change dramatically. For solar at high penetration, however, the marginal capacity credit of PV and CSP_0 decrease substantially from the capacity credit at low penetration and these resources begin to displace energy from coal plants. At high penetration more curtailment and energy sales at low energy prices is expected for PV and CSP_0 than for wind. Due to thermal energy storage, CSP_6 maintains a higher marginal capacity credit even at high penetration and avoids substantial curtailment and energy sales during times with low energy prices.

This section explores the impact of these trends on the relative differences in the marginal economic value of wind and solar and how the marginal economic value changes with increased penetration. The marginal economic value, as described in more detail in Section 3.4, is based on the DA and RT prices calculated with the equilibrium set of generation investments and the VG generation less any additional costs due to increased AS requirements for VG.

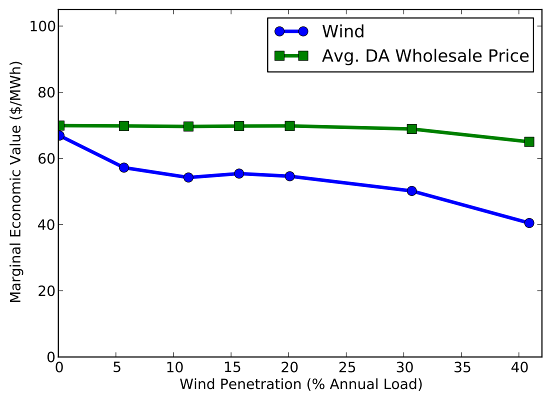
The calculated marginal economic value of wind, PV, CSP_0, and CSP_6 with increasing penetration of each VG technology is shown in Figure 10. For comparison purposes, the time-weighted average wholesale DA price in each case is also shown. The average wholesale price is relatively constant with increasing penetration of VG until high VG penetration levels. This relatively constant wholesale price with increasing VG is largely a result of the assumption that the rest of the non-VG system remains in long-run equilibrium. In particular, this assumption of long-run equilibrium requires prices to rise high enough and frequently enough to cover the fixed cost of any new non-VG investment. Since all cases require some new non-VG capacity to be built the prices must be sufficiently high to cover the fixed cost of that new non-VG generation. Only at very high penetration levels (>20% energy penetration) does the time-weighted average wholesale price begin to decrease, though the non-VG system remains in long-run equilibrium.

The marginal economic value of wind is found to be similar to (but slightly lower than) the average wholesale price at low penetration levels. As the penetration of wind increases to 20%, the marginal value of adding additional wind decreases by approximately \$12/MWh relative to the case without wind even though the average wholesale price does not change. At very high penetrations of 30% and 40% the marginal value of wind decreases further. At 40% wind penetration the time-weighted average wholesale price also begins to decrease.

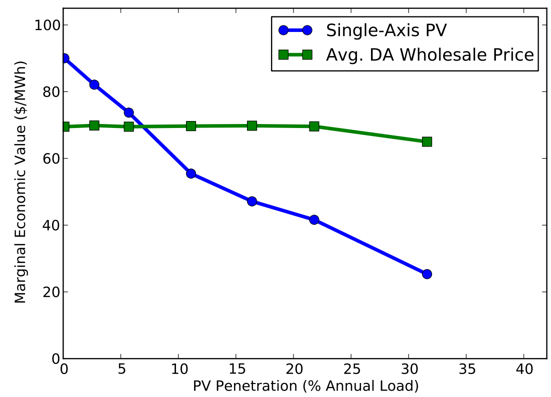
Based on the "market test" from Borenstein described earlier in Section 2.1, the marginal economic value of wind can be used to indicate the "grid-parity" cost where the economic value of the wind plant would equal the fixed cost of the wind plant. If the annualized fixed cost of wind is above the marginal economic value of wind, then no additional wind would be built based on this "market test" (of course more might be built based on other non-market factors including an RPS requirement or because of other factors not modeled here). If, on the other hand, the annualized fixed cost of wind were less than the marginal economic value of wind then it would be economically attractive to add more wind assuming again that no other factors are at play. The declining marginal economic value of wind with increasing penetration indicates that the cost of wind needs to be continuously driven lower to justify adding more wind strictly on economic grounds, particularly for adding additional wind beyond 20% penetration. Related, the value to a utility of adding more wind decreases when there is already significant wind penetration.

As shown in Figure 10, the marginal economic value of solar exceeds the time-weighted average wholesale DA price of power as well as the marginal value of wind at low penetration levels. The high value of solar, \$20–30/MWh higher than the average wholesale power price and the marginal economic value of wind, is due largely to the high degree of coincidence of solar generation and times of peak load and scarcity prices when using a demand profile based on California loads. This high degree of coincidence is also what led to the high capacity credit estimated earlier in Section 5.1. The high marginal economic value of solar resources at low penetration has been highlighted in several recent studies (e.g., Borenstein, 2008; Lamont, 2008; Sioshansi and Denholm, 2010). Of course, when comparing wind and solar resources in procurement decisions the higher marginal economic value of solar at low penetration must also be weighed against the relative levelized cost of wind and solar supply.

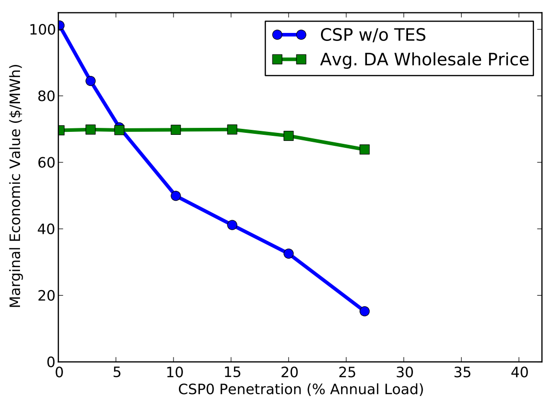
One particularly interesting result at low penetration levels is that the marginal economic value of PV, CSP_0, and CSP_6 are all relatively similar on a \$/MWh basis. This shows that there is not a strong economic signal at low penetration levels that would indicate that CSP with TES would be more valuable than a plant



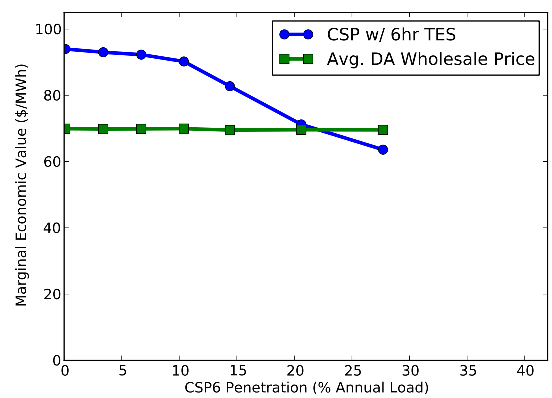
(a) Wind



(b) PV



(c) CSP_0



(d) CSP_6

Figure 10: Marginal economic value of variable generation and an annual flat-block of power with increasing penetration of variable generation in 2030.

without TES on a per unit of energy basis. It might be possible to justify the addition of TES to a CSP plant based on the fact that TES can increase the capacity factor of a CSP power block. Depending on the cost of TES and the cost of increasing the solar field size, adding TES may actually decrease the levelized cost of a CSP plant (Herrmann et al., 2004; Turchi et al., 2010). At low penetration, the cost reduction benefits would need to be the primary motivation for adding TES since there is not a clear increase in the value of CSP with TES relative to the value of CSP without TES. This finding supports the relatively sparse market interest in CSP with TES in markets that currently have low solar penetration.

As the penetration of solar is increased to 10% the marginal value of adding additional PV and CSP_0 drops significantly relative to the marginal economic value of adding additional CSP_6. At 10% penetration, the marginal economic value of adding additional CSP_6 is about \$4/MWh less than the value at 0% penetration. For solar without TES, in contrast, the marginal economic value of adding more solar at 10% penetration is \$35/MWh and \$50/MWh less than the value of adding solar at 0% penetration for PV and CSP_0, respectively. Also at about 10% penetration, the marginal economic value of PV and CSP_0 reach and then drop below the economic value of wind. The marginal economic value of CSP_6, on the other hand, remains above that of wind at all penetration levels considered here.

This relative difference in value at high penetration indicates that solar resources with TES can be substantially more valuable than resources without TES. Of course, the decision to procure CSP with TES relative to other solar technologies would also need to consider the relative cost of these options. If the recent rapid decrease in the price of PV is sustained and the cost of CSP with TES does not follow the same trajectory, then PV could still be a more attractive option for increasing solar penetration even with 10% PV penetration and despite the lower marginal economic value.

At higher penetrations of VG, the marginal economic value of adding additional PV or CSP_0 is below the marginal economic value of wind. While the economic value of wind starts lower than the value of the three solar technologies at low penetration, its value does not drop as fast as the marginal economic value of PV and CSP_0. In this particular case, the wind resources that are procured at high penetration levels increasingly come from diverse wind regions that are out-of-state. The diversity in the wind generation patterns and forecast errors are part of the reason for the slower decline in the value of wind with high penetration. Solar generation profiles, on the other hand, are largely dictated by the position of the sun. Geographic diversity can help mitigate short term variability issues due to clouds, but it does not impact the overall daily solar generation profile.

5.3 Decomposition of Marginal Economic Value

The marginal economic value of VG and the flat block of power can be decomposed into several components in order to better pinpoint the causes of the high economic value of solar at low penetration, the relatively slow decline in the value of wind with increasing penetration, the drivers for the steeper decrease in the value of PV and CSP_0 with higher penetration, and the reasons for the substantially higher value of CSP_6 relative to the other VG at high penetrations. Without this decomposition step it is not clear if these trends are due to changes in capacity credit, changes in thermal generation that is being displaced, imperfect forecastability, or AS impacts.

Specifically, using the method that is described in Section 3.4, in this section the marginal economic value of VG is decomposed into capacity value, energy value, DA forecast error, and AS impacts. All of these components are presented in terms of \$/MWh-of-VG such that the values can be easily compared.

Decomposing the marginal economic value in this way helps to understand the causes for changes in the value of VG and, perhaps more importantly, can help identify promising strategies for mitigating decreases in the marginal economic value of VG with increasing penetration. The results of the decomposition are shown in Table 11. For comparison, the marginal economic value of a flat block of power that is assumed to have no variable fuel or O&M cost is equivalent to the time-averaged wholesale DA price of power, which at low penetration levels is about \$70/MWh. The capacity value of a flat block between 0% to 30% penetration is found to be about \$20/MWh (or about \$170–180/kW-yr) and the energy value is about \$50/MWh.[47] Only

[47] The capacity value of a flat block is similar to the cost of capacity in this market, which corresponds to the fixed cost of

at 40% penetration does the energy value and capacity value of the flat block of power begin to decrease.

Up to 30% penetration the decomposition for wind shows that the marginal economic value of wind is less than the marginal value of a flat block due primarily to the lower capacity value of wind. As the penetration of wind increases from 0% to 20% penetration, for example, the marginal capacity value of wind decreases by \$8/MWh. The energy value of wind at 0% penetration is found to be similar to the energy value of a flat block of power. Moreover, the energy value only drops by \$2.5/MWh when the penetration of wind increases from 0% to 20%. At still higher penetration levels the capacity value of wind is relatively stable while the energy value begins to fall more noticeably between 30% and 40% penetration.

DA forecast error costs are found to be meaningful, though these costs do not impact the marginal economic value of wind as much as the declining capacity value and energy value in this particular region. In addition, while the absolute \$/year cost of forecast errors steadily increases with increasing wind penetration, the changes in the DA forecast error cost per unit of wind energy are somewhat ambiguous with increasing penetration. At first, as wind penetration grows from 0% to 10% the DA forecast error cost increases up to \$4/MWh. Between 10% to 20%, however, the DA forecast error cost declines to \$2/MWh and then begins to increase again at 30% penetration up to a cost of \$6/MWh at 40% penetration. There are three primary factors of the DA forecast error cost that can contribute to the variation: (1) the difficulty associated with managing DA forecast errors (measured by the standard deviation of the difference between the DA and RT price), (2) the relative magnitude of the DA forecast errors (measured by the standard deviation of the difference between the RT generation and the DA forecast for wind normalized by the annual wind generation), and (3) the correlation between DA and RT differences in prices and wind generation.

Each of these factors are examined in turn to better understand the causes of the variation in the DA forecast error cost. With increasing penetration of wind the relative magnitude of wind forecast errors decreases between 0% and 30% penetration due to increasing geographic diversity in wind sites and only slightly increases between 30% and 40% wind penetration. The correlation between DA and RT wind deviations and price deviations steadily increases with increasing penetration. The remaining factor, the difficulty with managing DA forecast errors, is therefore the main contributor to the variability of the DA forecast error cost with increasing penetration. Between 0% and 10% penetration the difficulty with managing DA wind forecast errors steadily increases. Between 10% and 20% penetration, however, the spread of differences between DA and RT prices decreases. This indicates that the cost of "purchasing" power in RT to make up for a generation shortfall between DA and RT or the discount for "selling" power in RT that exceeds the DA scheduled generation are lower between 10% to 20% penetration than between 0% to 10% penetration. Beyond 20% penetration the cost of purchasing power in RT or the discount for selling power in RT increases to levels beyond those at 10% penetration resulting in an overall increase in the DA forecast error cost at 40% penetration.

The ancillary service costs for wind are found to be low, less than \$1/MWh, and do not increase with increasing penetration. The large amount of hydropower in California helps to maintain low AS costs even with increasing AS targets. In all cases the time-weighted average price for regulation up remains in the range of \$8–10/MW-h. Hydropower does not entirely drive the AS costs, however, since similarly low AS costs and AS prices were observed during prior analysis by the authors of a region with significantly less hydropower (namely the Rocky Mountain Power Area) using the same model and similar assumptions. In addition, this price range for regulation up reserves is similar to the prices for regulation in recent years for several centralized markets in the U.S. (CAISO, MISO, and ISO-NE) but lower than regulation prices in other markets. Regulation prices in ERCOT, NYISO, and the CAISO prior to the recent market technology upgrade and redesign have been in the range of \$20–60/MW-h (Milligan and Kirby, 2010). Increases in the prices for ancillary services would potentially lead to higher costs for ancillary services for wind.

Interestingly, rather than AS costs increasing with increasing wind penetration, the AS costs actually slightly decrease with increasing penetration per unit of wind energy. The modeling assumptions in this analysis lead to AS targets increasing in proportion to the increase in energy generated by wind. As a result, if the AS prices (and their correlation with wind generation) did not change with increasing wind

new CCGT resources (\$200/kW-yr = \$23/MW-h). The energy value of a flat block is similar to the fuel and variable O&M cost of a fully loaded CCGT (\$46–52/MWh in the model used here, depending on the vintage).

Table 11: Decomposition of the marginal economic value of variable generation in 2030 with increasing penetration.

Component ($/MWh)	Penetration of a Flat Block 0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(170) 20	(180) 20	(170) 20	(180) 20	(180) 20	(180) 20	(140) 16
Energy Value	50	50	50	50	50	50	49
DA Forecast Error	0	0	0	0	0	0	0
Ancillary Services	0	0	0	0	0	0	0
Marginal Economic Value	70	70	70	70	70	70	65

Component ($/MWh)	Penetration of Wind 0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(69) 17	(37) 12	(30) 10	(30) 10	(28) 9	(25) 8	(25) 8
Energy Value	50	49	48	48	48	46	39
DA Forecast Error	-0.2	-3	-4	-2	-2	-3	-6
Ancillary Services	-0.4	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Marginal Economic Value	67	57	54	55	54	50	40

Component ($/MWh)	Penetration of PV 0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(120) 37	(110) 34	(82) 27	(39) 13	(24) 8	(11) 4	(4) 1
Energy Value	54	53	52	49	45	41	27
DA Forecast Error	-0.2	-5	-4	-6	-5	-4	-3
Ancillary Services	-0.9	-0.8	-0.7	-0.4	-0.2	-0.1	-0.0
Marginal Economic Value	89	81	73	55	47	41	25

Component ($/MWh)	Penetration of CSP_0 0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(110) 47	(84) 36	(54) 24	(22) 10	(11) 5	(6) 3	(5) 2
Energy Value	56	54	52	46	41	33	16
DA Forecast Error	-2	-5	-5	-6	-5	-4	-4
Ancillary Services	-1.1	-0.8	-0.5	-0.2	-0.1	-0.1	-0.1
Marginal Economic Value	100	84	70	50	41	32	14

Component ($/MWh)	Penetration of CSP_6 0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(150) 37	(160) 37	(150) 37	(150) 35	(100) 24	(85) 20	(61) 15
Energy Value	55	55	55	55	58	53	52
DA Forecast Error	-0.1	-1	-1	-1	-1	-2	-3
Ancillary Services	1.4	1.4	1.3	1.2	1.0	0.7	0.1
Marginal Economic Value	94	93	92	90	83	71	64

a - Capacity value in parentheses is reported in $/kW-yr terms and reported to two significant digits.

penetration then the cost of AS for wind would remain relatively constant with increasing wind production. In fact, the slight decrease in the cost of AS for wind with increasing penetrations shown in Table 11 and the relatively stable time-averaged AS prices indicates two potential changes that may occur as the penetration of wind increases. First, the AS prices could become lower specifically during times when wind power is generating and higher at other times as the penetration of wind increases from 0%. Second, wind could be selling more AS in the form of regulation down with increasing penetration. Examination of regulation down from wind shows that it does increase with increasing wind penetration, but the impact is negligible (less than $0.003/MWh at 40% penetration). Thus the price of AS must decrease during hours with high wind penetration. Previous analysis of modeled regulation prices with increasing wind production in ERCOT noticed a similar trend. In a previous study by GE, regulation prices were found to decrease with increasing wind penetration even though the total regulation requirement increased (GE Energy, 2008).[48]

Though the findings are specific to the cases analyzed, overall, the decomposition of the value of wind shows that:

- The primary value of wind is the energy value. The energy value of wind at low penetration is similar to the variable cost of energy from a fully loaded CCGT. At high penetration, the energy value starts to decline as wind displaces energy from incumbent coal plants.
- The capacity value of wind is slightly less than the capacity value of a flat block of power at zero penetration. The capacity value of wind drops as penetration increases, but is relatively stable at a low value at medium to high penetration.
- The cost of day-ahead forecast errors is impacted by the degree of the wind site diversity, but remains below $5/MWh except at very high penetration.
- Ancillary service costs are modest, less than $1/MWh, and do not significantly increase at high penetration levels at least for the cases analyzed here.

These conclusions are broadly consistent with findings of the many detailed operational and valuation studies that have explored the impacts of higher levels of wind penetration. In particular, the ancillary service cost and day-ahead forecast error cost for wind are within the range, though on the lower end, of "integration costs" found in various operational integration studies of wind (DeCesaro et al., 2009). It should be recognized that there is some controversy regarding how these costs should be calculated and interpreted (Milligan et al., 2011).

The decomposition of the value of the three solar technologies shows that at low penetration, the primary reason that the value is greater than that of a flat block and of wind is due to the substantially greater capacity value. At 0% penetration, the capacity value of solar is $17–27/MWh greater than the capacity value of a flat block (and more so when compared to wind).

Based on the earlier finding that the effective capacity credit of CSP_6 at low penetration was greater than the capacity credit of the other solar technologies, it is somewhat counter-intuitive that the capacity value of CSP_6 is not greater in dollars per unit of energy ($/MWh) terms, though it is greater in dollars per unit of nameplate capacity ($/kW-yr) terms. The reason is that the CSP_6 technology produces more energy per unit of nameplate capacity than the other solar technologies. As an illustration, consider two different 100 MW power plants that both earn the same $8 million/yr revenue during hours with scarcity prices (or $80/kW-yr), but one plant generates 200 GWh/yr and the other generates 400 GWh/yr. The plant that produces more energy over the year will have a lower capacity value of $20/MWh while the plant that produces less energy over the year will have a higher capacity value of $40/MWh. Along the same lines,

[48]This is explained by GE as follows: "In general, with increasing wind generation capacity, the unit price per MWh of spinning reserve decreases due to several factors. First, the balance of generation is provided by units with lower variable costs as wind generation capacity is increased. Second, because of the daily variability of wind generation, thermal units with long start-up times and minimum-run times tend to be scheduled for hours where their dispatch levels are reduced by wind output. This provides regulating range with virtually no opportunity cost for these high-wind hours. Third, the accuracy of wind forecasting used in the day-ahead unit scheduling plays a role. If wind generation forecasts are not considered at all, or are heavily discounted, the balance of generation will tend to be over-committed"(GE Energy, 2008).

consider the same two 100 MW plants but the plant that generates 400 GWh/yr earns the full \$8 million/yr revenue during hours with scarcity prices whereas the generation profile of the plant that generates 200 GWh/yr is such that it earns only \$4 million/yr during hours with scarcity prices (or \$40/kW-yr). The capacity value of both plants would be equal to \$20/MWh, notwithstanding the high capacity credit and the high capacity value in \$/kW-yr terms associated with the former.

Similarly, even though the CSP_6 technology is more likely to be producing power during scarcity hours and has a higher capacity value in \$/kW-yr terms it produces more energy per unit of capacity and therefore has a similar capacity value, in \$/MWh terms, to the other solar technologies. This also explains how the capacity value of CSP_0 can be greater than the capacity value of PV at zero penetration level in \$/MWh terms even though the capacity value in \$/kW-yr terms of CSP_0 is slightly lower than the capacity value of PV in \$/kW-yr terms. The difference between the capacity value of PV and CSP_0 in \$/MWh terms is due to the lower amount of energy per unit of nameplate capacity for CSP_0 relative to PV.

The energy value of solar at 0% penetration is found to be \$4–6/MWh greater than the energy value of a flat block because it displaces relatively less efficient, and therefore higher cost, gas plants during periods of high demand in summer. At 0% penetration the energy value of solar is similarly \$4–6/MWh greater than the energy value of wind.

The AS and DA forecast error cost for PV and CSP_0 are small in magnitude relative to the energy value and capacity value, and are also similar in magnitude to the AS and DA forecast error cost for wind. Variations in AS and DA forecast error costs for PV and CSP_0 with increasing penetration are driven by similar factors as for wind, discussed earlier. Similar to what was found for wind, the DA forecast error cost increases in absolute \$/year terms with increasing penetration, but the marginal DA forecast error cost per unit of solar energy does not monotonically increase with increasing penetration. Detailed analysis of the factors driving the DA forecast error cost similarly shows that the relative magnitude of forecast errors decreases with increasing penetration and that variations in the DA forecast error cost are primarily related to variations in the difficulty of managing DA forecast errors at different penetration levels.

One important difference with wind, however, is that further examination of the AS costs for PV and CSP_0 at high penetration levels shows that the sales of regulation down begin to become relatively more important in keeping the cost of ancillary services at the very low level at high penetration. At 0% penetration, for example, the cost of purchasing AS for CSP_0 is about \$1.1/MWh and the revenues from selling regulation down from CSP_0 is zero, leading to a net cost of AS for CSP_0 at 0% penetration of about \$1.1/MWh, as reported in Table 11. At 30% penetration, on the other hand, the cost of purchasing AS for CSP_0 is about \$1.5/MWh and the revenues from selling regulation down from CSP_0 increases to about \$1.4/MWh, leading to the reported net cost of AS of only \$0.1/MWh. Revenues from the sale of regulation down only begins to exceed \$0.05/MWh for CSP_0 penetration levels above 10%, indicating that provision of regulation down by CSP_0 plants is only found to be useful at higher penetration levels. Similar behavior is observed for the sale of regulation down by PV at high penetration levels.

The net AS portion is positive for CSP_6 indicating that CSP_6 resources are earning revenue from selling AS whereas the other VG technologies are net buyers of AS at all penetration levels. Regardless, because AS prices are found to be low (in the range of \$8–10/MW-h for regulation up), the AS revenue earned by CSP_6 is found to be relatively low, under \$2/MWh. As mentioned earlier in this section, if the AS prices were to be higher (as they are in some organized markets within the U.S.) the AS revenue for CSP_6 could potentially be higher. Though AS costs are relatively small, the provision of regulation down by PV and CSP_0 at high penetration levels and provision of AS by CSP_6 appears to be an area where further research and demonstration of technical capabilities might be of interest. Similar research is being conducted for wind (e.g., Kirby et al., 2010). Additional research specifically on the impact of ancillary service revenues for CSP with TES based on historical energy and AS prices is available from Sioshansi and Denholm (2010).

In all penetration levels the DA forecast error costs are found to be substantially larger than AS costs. Although DA forecast errors caused a decrease in the value of CSP_0 of up to \$6/MWh, the same type of DA forecast errors were managed by the CSP_6 resource at a cost of at most \$2/MWh. This may represent an upper bound to the value of TES in managing DA forecast errors, however, since perfect foresight is assumed in RT for the management of DA forecast errors.

The most dramatic change in the marginal value of VG resources is the decrease in capacity value of PV and CSP_0 with increasing penetration levels. By the time the penetration reaches 10% on an energy basis, the marginal capacity value decreases by \$24/MWh and \$37/MWh from the marginal capacity value at 0% penetration for PV and CSP_0, respectively. While at low penetration the marginal capacity value of PV and CSP_0 are considerably greater than the capacity value of wind and of a flat block of power, at 10% penetration the marginal capacity value from adding additional PV or CSP_0 is comparable to the marginal capacity value from adding additional wind. Beyond 10% penetration the capacity value of PV and CSP_0 continues to drop steeply relative to that for wind.

The change in capacity value with increasing penetration of PV and CSP_0 is explained in Figure 11. The figure shows the historical hourly load shape scaled up to 2030 and the net load (historical load less hourly solar generation) on three days of the year where high load leads to scarcity pricing. The net load is shown for increasing penetrations of PV. The log of the hourly wholesale price is also shown in the figure to illustrate the coincidence of times of high system need with times of solar generation. PV generates significant amounts of power during the scarcity period at low penetration levels, but as the penetration of PV increases, times with high net load and high prices shift towards the early evening, when PV production has dropped off. As similarly found in Section 5.1, PV generation clearly reduces the need for new capacity at low penetration, but with increasing penetration PV is less effective at reducing that need.

A similar net-load curve and pricing is shown with increasing levels of CSP_6 on the same three days, Figure 12. The addition of TES allows solar generation during the day to be shifted into the early evening and reduce the peak net load at higher penetration levels. As a result, the times with scarcity prices do not shift as much as in the PV case and solar generation remains high during times with scarcity prices. The end result is that the capacity value of CSP_6 remains relatively high over all penetration levels considered and only begins to meaningfully decline above 10% penetration.

In contrast to the steeply declining capacity value of PV and CSP_0 at high penetration levels, the capacity value of wind is relatively stable with increasing penetration for two reasons: first, the low capacity credit of wind means that even as wind is added, the times with the peak loads and scarcity prices largely remain the same times even as penetration increases. Second, while wind is not producing a significant amount during times with peak loads and scarcity prices, many wind sites are producing a small amount. Adding more wind sites that have a small probability of producing power during these times keeps lowering the total peak net load slightly with increasing penetration. As a result the small capacity credit of wind is maintained even with high wind penetrations.

The marginal energy value of PV and CSP_0 also decline at a faster rate than the marginal energy value of wind. As a result, at 15% penetration, the energy value of PV and CSP_0 is less than the energy value of wind. The lower energy value for PV and CSP_0 at 15% penetration can be explained in part by the fact that in some hours of the year (<2% of the hours in a year) incumbent coal resources are dispatched to less than their nameplate capacity, while incumbent coal is found to be always at its full capacity with 15% wind. In particular, as PV and CSP_0 increases, incumbent coal tends to be dispatched down in winter and spring months during early morning hours on weekends when solar generation increases faster than the morning load picks up. The displacement of coal increases further with higher PV and CSP_0 penetration, and coal begins to be dispatched down with wind at 20% penetration. By 30% penetration, the incumbent coal is found to be dispatched below their nameplate capacity 5% of the year with wind and over 25% of the year with PV and CSP_0. The energy value of VG decreases when coal is displaced due to the lower full load variable cost of energy from coal (\$27/MWh) relative to the full load variable cost of energy from CCGT resources (\$46–52/MWh).

The energy value of CSP_6 on the other hand, remains greater than or equal to the fully loaded cost of energy from a CCGT resource even at 30% penetration. The decrease in the total marginal value of CSP_6 with increasing penetration is due to the declining capacity value after a penetration of 10%. As described earlier in Section 5.1, increasing penetrations of CSP_6 begin to reduce price spikes and involuntary load shedding as the penetration increases above 10%. This decreases the need to build new conventional capacity to meet peak loads in the summer. At the same time, reducing the amount of new generation

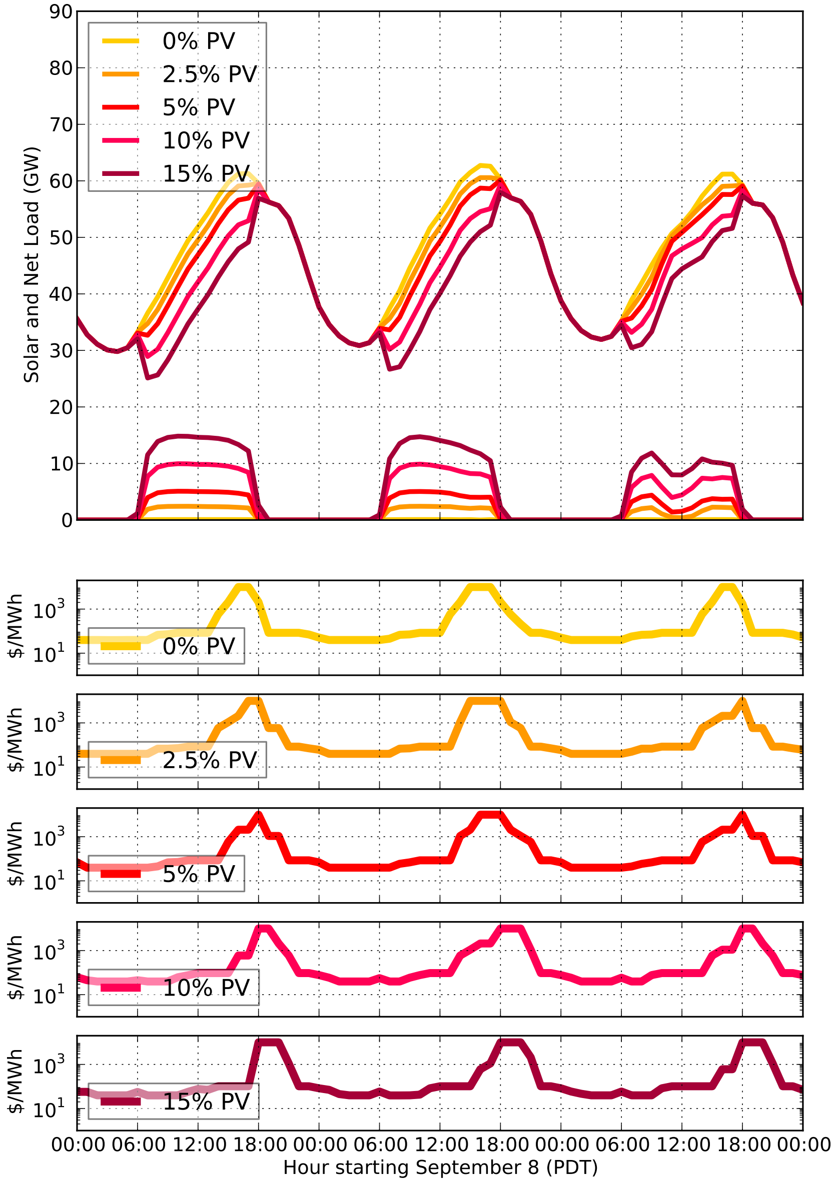


Figure 11: Historical load less the generation from PV and hourly energy prices on three peak load days with increasing PV penetration.

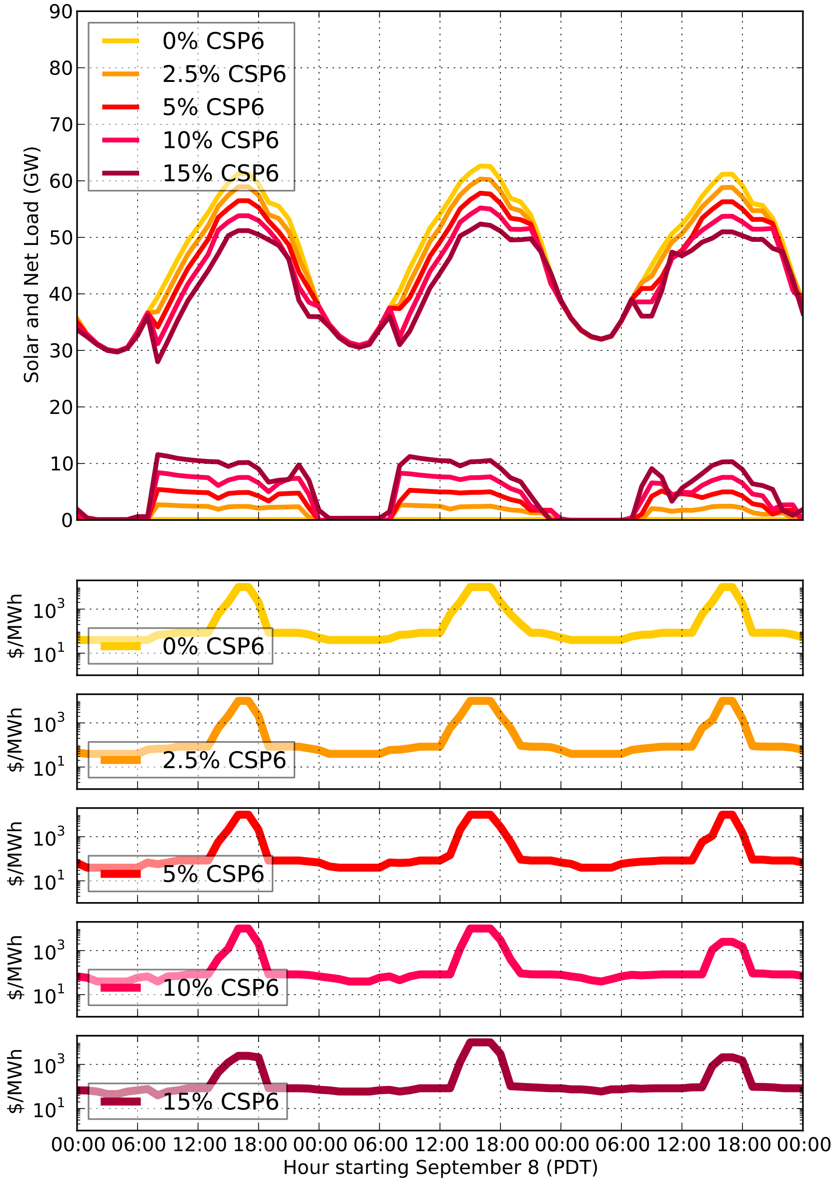


Figure 12: Historical load less the generation from CSP$_6$ and hourly energy prices on three peak load days with increasing CSP$_6$ penetration.

capacity that is built starts to lead to a situation where the lower conventional capacity and the lower solar production in the winter months becomes the most constrained time for the power market. The constraints are not due to insufficient generation capacity but due to insufficient energy. Either way new conventional capacity is needed to balance the available generation and demand. This particular result depends on how much energy is available from hydropower and the CSP_6 in winter months, factors that would not normally be considered in reliability based studies that focus primarily on periods with peak loads. As the penetration of CSP_6 increases, the shift from a capacity-constrained to an energy-constrained system causes the capacity value to begin to decrease at these high penetration levels.[49] Eventually the value of CSP_6 is found to be lower than the average DA wholesale price.[50] Even at 30% penetration, however, the marginal economic value of CSP_6 is found to be well above that of wind (+$14/MWh) and of PV and CSP_0 (+$45/MWh and +$50/MWh).

In sum, the main contributor to the decline in the marginal economic value of wind, PV, and CSP_0 are changes in the capacity value for penetrations between 0% and 10% and changes in the energy value with greater penetration. The change in capacity value at low penetration can lead to a decrease on the order of $24–37/MWh in the value of PV and CSP_0 and a decrease on the order of $7/MWh for wind. The change in the energy value between 10% penetration and 20% penetration can decrease the value of PV and CSP_0 by $8–13/MWh, while the change in the energy value between 10% and 40% can decrease the value of wind by $8/MWh. The cost of DA forecast errors do not dramatically increase with increasing penetration, but they are not negligible at $2–6/MWh. The cost of ancillary services, given the assumed AS procurement rule, are consistently less than $2/MWh for wind, PV, and CSP_0. Because of TES, CSP_6 is able to avoid—to some degree—many of these factors that otherwise drive down the marginal economic value of VG. As a result, especially at high penetration, the marginal economic value of CSP_6 is considerably higher than for the other resources considered.

5.4 Sensitivity Cases

To explore the sensitivity of these results to a small subset of important parameters, four sensitivity cases were developed:

- **No operational constraints:** Relax major operational constraints in the dispatch model to quantify the impact of operational constraints on the marginal economic value of VG.
- **Carbon cost:** Increase the cost of energy through a price on carbon to illustrate the sensitivity of the marginal value of VG to inclusion of one type of externality.
- **Cost of capacity:** Reduce the cost of capacity from conventional resources to demonstrate the impact of lower capital costs for CTs and the shifting of new investments toward CTs instead of CCGTs.
- **No retirements:** Assume that plants do not have a technical life and therefore that no plants that exist today will retire by 2030 for technical reasons. This tests the sensitivity of the marginal economic value to the assumption about the technical life of incumbent plants.

Key results from the four sensitivity cases are described below.

[49] The changing dispatch of the incumbent generation capacity, including the increasing capacity factor of CTs in the winter months described in Section 5.1.2, may in part explain the slight increase in the energy value of CSP_6 at 15% penetration.

[50] We tested whether there is notable value in increasing the size of the thermal storage at higher penetration levels. We found that increasing the thermal storage from 6 hours to 10 hours of thermal storage with the same sized solar field as used in the CSP_6 cases (a solar field multiplier of 2.5) only increased the value by $1–2/MWh relative to CSP_6 at 20% penetration. In contrast, increasing the thermal storage to 10 hours and simultaneously increasing the solar field size (a solar field multiplier of 3) increased the value by about $8/MWh relative to CSP_6 at 20% penetration. The increase in value was due to an increase in capacity value and energy value and a small decrease in the DA forecast error cost. Additional research on how the optimal thermal storage and solar field multiplier change depending on penetration (and deployment of other VG resources) is an area where additional research should be conducted.

5.4.1 No Operational Constraints

In order to determine how much of the decline in the economic value of VG was due to operational constraints on conventional generation and hydropower, a sensitivity case was run where major operational constraints were relaxed.

The dispatch in this case resembled a pure-merit order dispatch because power plants were assumed to be able to startup and shutdown without cost, ramp between zero output and full generation at any rate, and not experience part-load efficiency penalties related to low output levels. Furthermore any unit was assumed capable of providing each type of reserves. Hydropower was assumed to no longer be restricted by a minimum flow constraint.[51]

Though this unconstrained case is not a realistic representation of the power system, the difference in the marginal economic value of VG between the un-constrained sensitivity case and the case with the operational constraints indicates the importance of modeling such constraints, Figure 13. The difference in the value of wind with and without operational constraints considered, for example, at up to $5/MWh, is similar to the size of the day-ahead forecast error cost for wind. Furthermore, decomposition of the value of wind without operational constraints[52] shows that the capacity and energy value of wind do not change significantly with and without operational constraints in California. This leads to the conclusion that the factors affecting the day-ahead forecast error costs (e.g., DA commitment of non-quick-start generation and costs and capacity of quick-start generation) are some of the most important constraints to model for wind in this case study in addition to the merit-order dispatch.

At low penetration levels, the operational constraint sensitivity case demonstrates that the initial decrease in the marginal value of PV and CSP_0 would still occur even if the system were perfectly flexible. The no constraints scenario only modestly increases the value of PV and CSP_0.

On the other hand, at high penetration levels the relative difference in the marginal economic value for PV and CSP_0 between the no constraint and reference case is large and far exceeds the cost of the day-ahead forecast errors. As shown in the Appendix E, removal of operating constraints substantially increases the energy value at high penetration relative to the energy value in the reference scenario, suggesting that said removal allows the system to not dispatch down coal. This suggests that operational constraints that might impact energy value, such as the thermal generator ramp rate limits and minimum generation constraints, may be more important for understanding the decline in the value of PV and CSP_0 at very high penetration levels (>20% penetration or so). The difference in the value of CSP_6 with and without the operational constraints shows no strong trend, suggesting that increasing CSP_6, as modeled in this study, does not push the limits of power system operations in the same way as PV, CSP_0, and wind.

5.4.2 Carbon Cost

Adding a carbon cost in the model increases the variable cost of thermal generation and therefore increases the energy value of variable generation. The increase in the marginal economic value of VG with a carbon cost relative to the reference case which had no carbon cost is shown in Figure 14.

With a carbon cost of $32/tonne CO_2,[53] the value of a flat block of power increases from about $70/MWh ($20/MWh capacity value and $50/MWh energy value) to just over $80/MWh ($20/MWh capacity value and $63/MWh energy value).

[51] More specifically, the operational constraints that were relaxed include the following:

- Conventional thermal generation: start-up costs removed from objective function and short-run profit calculation, minimum generation constraint relaxed, all plants able to offer non-spinning reserves even if offline, ramp rate limits removed for non-spinning, spinning, and regulation reserves and for hour to hour changes in energy, no day-ahead commitment decisions are binding in real time. Removing these constraints allows generation vintages to always operate at full load and therefore results in no part-load efficiency losses.
- Hydropower generation: relaxed minimum flow constraint, removed ramp rate limits for reserves and hour to hour changes in energy production.

[52] See Table 25 in Appendix E.

[53] The carbon cost is similar to the cost used in economic evaluations of generation resources in transmission planning studies at WECC (WECC, 2010).

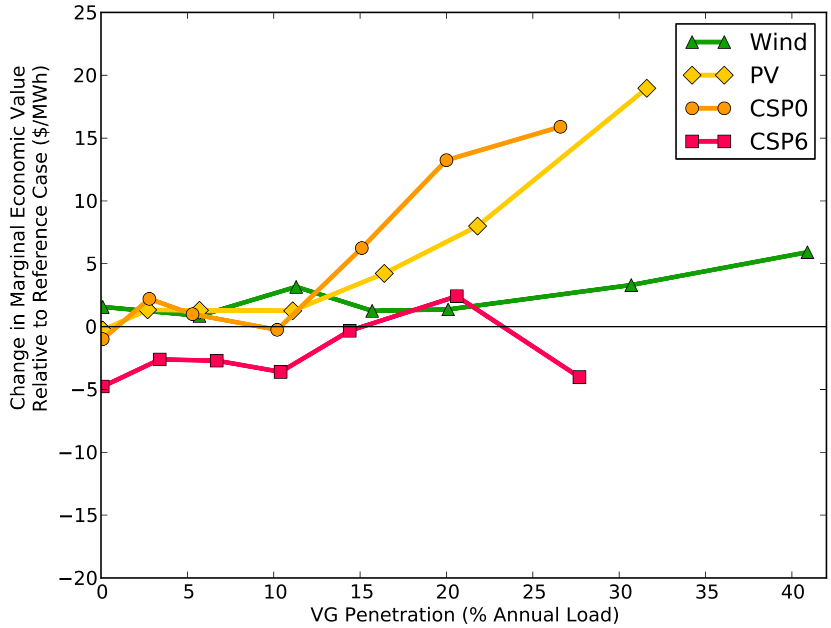


Figure 13: Difference in marginal economic value of variable generation between a case where the operational constraints for thermal and hydropower generation are ignored and the reference case.

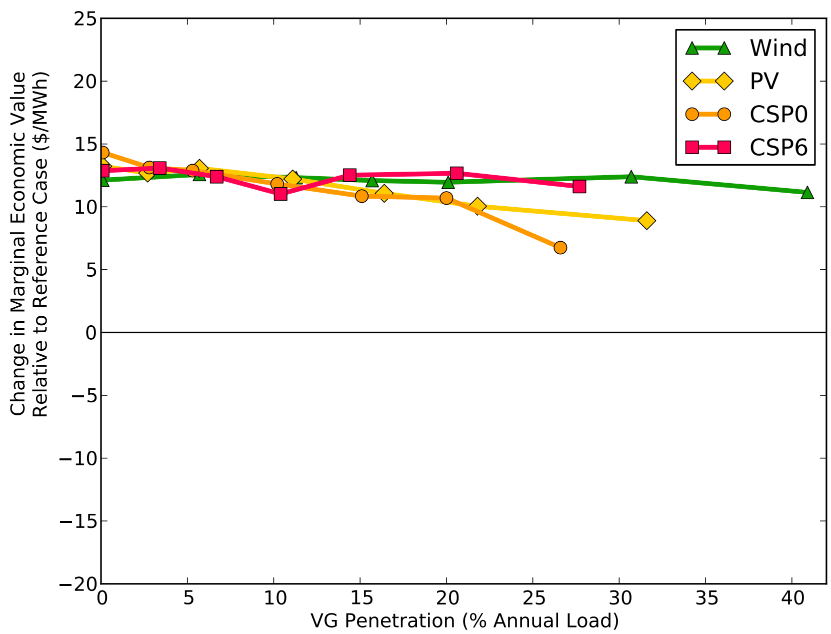


Figure 14: Difference in marginal economic value of variable generation between a case with a \$32/tonne CO_2 carbon cost and the reference case without a carbon cost.

The only noticeable change in the value of wind in the carbon cost case comes in the form of an increase in the energy value of wind across all penetration levels of \$11–13/MWh. This increase in the energy value is expected since wind was shown to have an avoided emissions rate in the range of 380–390 kg CO_2/MWh in Table 8. At this rate of avoided emissions, wind would decrease carbon costs by \$12/MWh when the cost of carbon is \$32/tonne CO_2. The capacity value, DA forecast error, and AS cost of wind do not noticeably change under the carbon cost scenario.

Similar to wind, the addition of a carbon cost to the solar cases only has a noticable impact on the energy value. Furthermore, the increase in energy value from the higher carbon cost is also similar to the increase in energy value that would be expected based on the avoided emission rates reported in Table 8. At low penetration levels, the avoided CO_2 emissions rate for PV and CSP_0 is 400–410 kg CO_2/MWh leading to an expected increase in energy value with a carbon cost of \$32/tonne CO_2 of \$13/MWh. At high penetration levels the avoided CO_2 emissions rate for PV and CSP_0 is 350 kg CO_2/MWh leading to an expected increase in energy value with a carbon cost of \$32/tonne CO_2 of \$11/MWh. The actual increase in the energy value is about \$13/MWh at low penetration and \$10/MWh at high penetration.

5.4.3 Cost of Capacity

The cost of capacity is an important driver of the capacity value of variable generation. Reducing the cost of new gas-fired CTs from \$194/kW-yr in the reference scenario to \$139/kW-yr[54] in the sensitivity scenario results in a change in investments from only CCGTs in the reference case to a mixture of new CTs and new CCGTs in this sensitivity scenario. Without VG about 32% of the new capacity that is built is from CTs and the rest of the new capacity remains CCGTs. At low penetration levels of PV and CSP_0 the proportion of CTs slightly declines. At 10% PV penetration and above, however, the proportion of CTs increases with increasing penetration. The proportion of CTs steadily increases with increasing wind penetration. In contrast to the other VG technologies, the proportion of CTs steadily declines with increasing penetration of CSP_6 and at 15% penetration and above CTs are no longer built even with the reduced capital cost of CTs.

Reducing the cost of CTs also results in shorter periods with scarcity prices and therefore a lower capacity value for both a flat block and for variable generation. The capacity value of a flat block decreases from \$20/MWh in the reference case to \$16/MWh in the case with the lower cost of capacity. The capacity value of solar at low penetration, specifically 0% penetration, decreases by \$7–8/MWh and the capacity value of wind at low penetration decreases by \$4/MWh.[55] At 20% penetration, the capacity credit is lower for VG leading to less sensitivity in the capacity value to changes in the cost of capacity.

Overall, the impact of the lower cost of capacity on the marginal economic value of VG is somewhat ambiguous. CT resources have a worse heat rate than CCGTs, which leads to higher energy costs during the increasing times when CTs are dispatched. Therefore, although the reduction in the cost of capacity decreases capacity value, the increase in the dispatch of less efficient generation increases the energy value of a flat block and of VG. The energy value of a flat block in the low cost of capacity case, for example, is \$54/MWh, \$4/MWh greater than the energy value of a flat block in the reference case. At low penetration, the energy value of wind is \$4/MWh higher and the energy value of solar is \$5–6/MWh higher in the low cost of capacity case than the energy value in the reference case. At high penetration, the energy value of wind remains about \$4/MWh higher while the energy value of solar is \$1–2/MWh higher in the low cost of capacity case relative to the energy value in the reference case. In sum, even though the lower cost of capacity decreases the capacity value of VG, the overall change in the marginal economic value is small due to the opposing increase in the energy value, Figure 15.

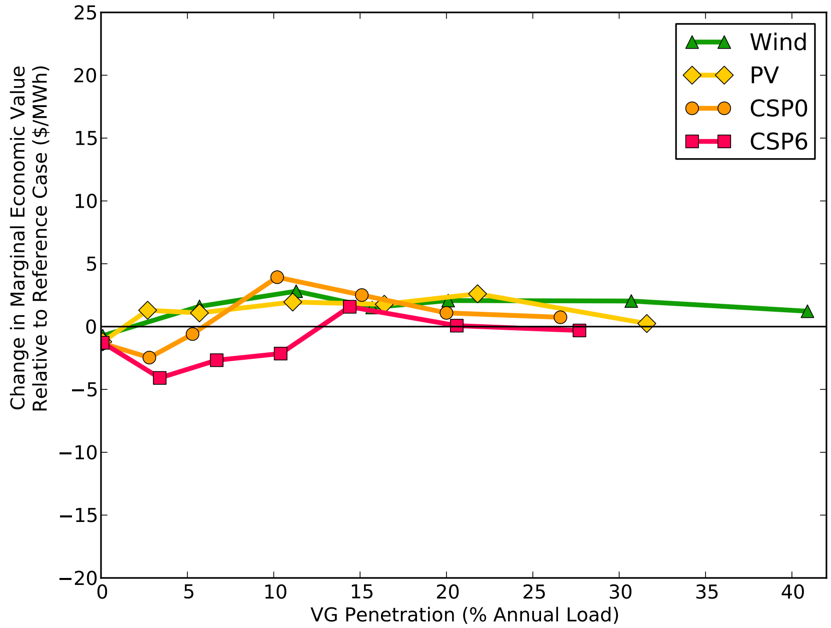


Figure 15: Difference in marginal economic value of variable generation between a case with a lower cost of combustion turbines and the reference case.

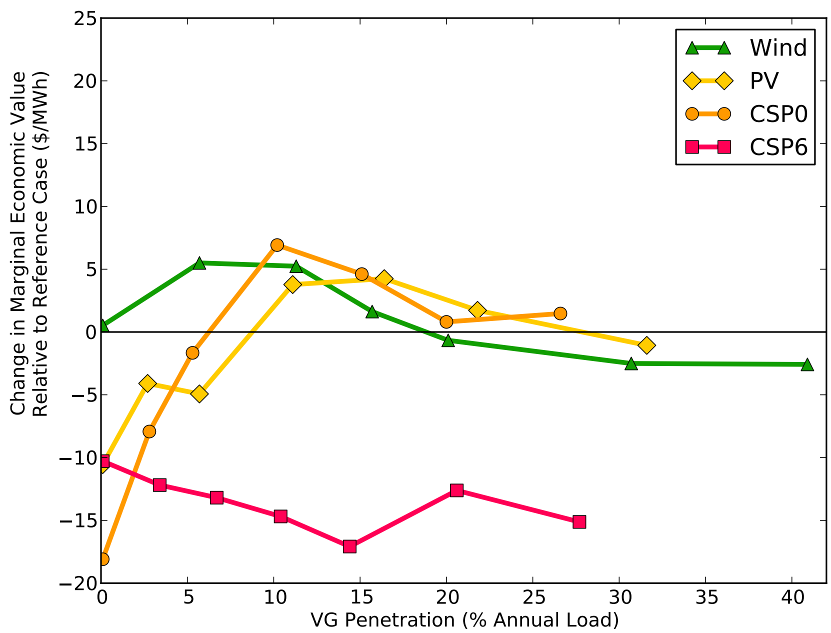


Figure 16: Difference in marginal economic value of variable generation between a case without retirements of existing generation and the reference case where generation is retired after a technical life.

5.4.4 No Retirements

Without retirements of existing generation due to plants reaching the end of their technical life, significantly more incumbent natural gas steam turbines along with additional older CT and CCGT generation is available in 2030 than in the reference scenario. The total incumbent non-VG capacity is 69.4GW in the no retirements scenario in comparison to 45.5 GW in the reference scenario. Even without VG, however, in the no retirements scenario a portion of this incumbent capacity, about 9.2 GW, was found by the model to retire for economic reasons because the short-run profits of these incumbent generators were insufficient to cover their assumed fixed O&M cost; in the reference scenario, no economic retirements were found to occur. A small amount of new CCGT (1.5 GW) were also built in the no retirement scenario without VG. A large portion of the short-run profit for these new CCGTs was found to be derived from hours where less efficient plants with higher variable costs were setting the energy price. In the reference case, on the other hand, hours with scarcity prices provided the majority of the short-run profit of new CCGTs. In total, the nameplate capacity of generation in the no retirements scenario without VG was 61.8 GW, slightly greater than the 60.1 GW of nameplate capacity of generation in the reference scenario without VG. The greater amount of total generation in the no retirements scenario can be explained by the lower cost of capacity: in the no retirements scenario the cost of capacity is simply the assumed fixed O&M cost of the natural gas steam turbines that retire for economic reasons (about $66/kW-yr) whereas in the reference scenario the cost of capacity is similar to the cost of the new CCGTs (about $200/kW-yr). With a cost of capacity of around $200/kW-yr in the reference case it is economically more attractive to shed load for load levels that occur less than 20 hours a year whereas with the lower cost of capacity it is more economically attractive to shed loads that occur only 6–7 hours per year. Hence, without VG the total nameplate capacity in the no retirements scenario is found to be greater than the total nameplate capacity in the reference scenario.

One of the impacts of these changes is that, at low penetration levels, the capacity value of solar and wind resources is lower in the no retirements case than it is in the reference case. The energy value, on the other hand, is somewhat higher since VG displaces less efficient plants. How these two opposing trends impacts the total value of VG depends on the technology and the penetration level. At low penetration levels for solar, the net result is that the value of solar in the no retirements case is lower than it is in the reference case, Figure 16. At 10% and 15% penetration, however, the higher energy value of PV and CSP_0 leads to a net greater value than the reference case. At 20% and 30% penetration the value of PV and CSP_0 in the no retirements case is about the same as the value in the reference case. The value of CSP_6 in the no retirements case remains below the value in the reference case at all penetration levels. The reason is that although the energy value of CSP_6 increases relative to the reference scenario, the capacity value of CSP_6 decreases by a larger amount across all penetration levels. The value of wind is greater in the no retirements case for penetration levels of 15% and below but becomes slightly less valuable at higher penetration levels. Overall, these results suggest that the value of VG can be relatively sensitive to assumptions about retirements.

6 Conclusions

Understanding the economic value of variable generation is important for making long-term decisions about renewable procurement and supporting infrastructure. This paper uses a unique modeling framework that captures both long-run investment decisions as well as dispatch and operational constraints in order to understand the long-run marginal economic value of wind, PV, and CSP with and without thermal energy storage and how that value changes with increasing penetration levels. Though the model only captures a subset of the benefits and costs of renewable energy, it provides unique insight into how the value of that subset changes with technology and penetration level. Pollution emissions were not the focus of this analysis, and as such we did not include the impact of many emissions related policies, though emissions were

[54] The lower cost of capacity is based on the benchmark "cost of new entry" (CONE) levelized revenue requirement for the 2014-15 period in the PJM forward capacity market: `http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx`. The CONE for this period is $139/kW-yr.

[55] see Table 27 in the Appendix for the decomposition of the marginal economic value of VG in this sensitivity case.

estimated as a byproduct of the investment and dispatch decisions. The decrease in emissions of CO_2, NO_x, and SO_2 with increasing penetration of variable generation illustrates that there are additional benefits of variable generation that were not monetized in this analysis.

The results from this case study implementation of the model demonstrate that the narrowly-defined economic value and changes in economic value with increasing penetration differ among variable renewable technologies. Not only does the economic value vary by renewable energy technology and penetration but the ordering of renewable energy technologies based on marginal economic value also change with penetration. The magnitude of these variations suggests that investors, resource planners, and policy makers should carefully consider the economic value and relative differences in the economic value among renewable energy technologies when conducting broader analyses of the costs and benefits of renewable energy. Nor should these evaluations be static—as renewable energy penetration increases new analysis will be needed. Also important is identifying ways to minimize the decline in value of variable renewable energy with penetration. Though that has not been the focus of the present work, by decomposing changes in economic value into capacity value, energy value, day-ahead forecast error and AS costs the present work can inform future analysis of these mitigation options. This analysis can also inform the design of simplified renewable procurement and transmission planning tools, like the WREZ model or other simple screening tools, by illustrating the relative importance of changes in the economic value of VG with increasing penetration to other factors that would be included in the simplified tools. The change in the value of PV and CSP_0 with increasing penetration should be given particular attention in such tools. More specifically, the key conclusions from this case study assessment of California include the following:

- *Solar has high value at low penetration:*

  The marginal economic value of solar at low penetration levels is high in California. This high value at low penetration is largely due to the ability of solar resources to reduce the amount of new non-VG capacity that is built, leading to a high capacity value. The magnitude of the capacity value of solar resources depends on the coincidence of solar generation with times of high system need, the cost of generation resources that would otherwise be built, and decisions regarding retirement of older, less efficient conventional generation.

- *There is little apparent value to thermal storage at low solar penetration:*

  At low penetration levels in California, we find that there is no strong increase in value per unit of electricity associated with adding TES to CSP plants. TES may be justified for minimizing the levelized cost of CSP plants, but there is no clear evidence in the present analysis that it is required to maximize economic value at low solar penetration.

- *The value of PV and CSP without thermal storage drop considerably with high penetration:*

  Without any mitigation strategies to stem the decline in the value of solar, the value of PV and CSP_0 drop considerably with increasing penetration. For penetrations of 0% to 10% the primary driver of the decline is the decrease in capacity value with increasing solar generation. Additional PV and CSP_0 are less effective at avoiding new non-VG capacity at high penetration than at low penetration. For penetrations of 10% and higher the primary driver of the decline is the decrease in the energy value. At these higher penetration levels additional PV and CSP_0 start to displace generation with lower variable costs. The operational constraints of thermal generation and hydropower contribute to the declining energy value of PV and CSP_0 at high penetration levels. At 20% solar penetration and above, there are increasingly hours where the price for power drops to very low levels, reducing the economic incentive for adding additional PV or CSP_0, and eventually there is curtailment of a portion of the energy generated by those solar technologies. The decline in the value is not driven by the cost of increasing AS requirements and is not strongly linked to changes in the cost of DA forecast errors.

- *At medium to high penetration CSP with thermal storage is considerably more valuable relative to PV and CSP without thermal storage:.*

The value of CSP_6 also decreases at higher penetration levels but not to the extent that the value of PV and CSP_0 decline. As a result, at higher penetration levels the value of CSP with thermal storage is considerably greater than the value of PV or CSP_0 at the same high penetration level. The capacity value of CSP_6 remains high up to penetration levels of 15% and beyond because the thermal energy storage is able to reduce the peak net load even at higher CSP_6 penetration levels. Power system operational constraints are less severe for high penetrations of CSP_6 due to the ability to use thermal energy storage, as modeled in this analysis, to avoid pushing against any such constraints.

- *The value of wind is largely driven by energy value and is lower than solar at low penetration:*

  The value of wind is found to be significantly lower than solar at low penetration due to the lack of correlation or slightly negative correlation between wind and demand or wind and high prices. This lower value of wind is largely due to the lower capacity value of wind and at least for low to medium penetrations of wind the decline in the total marginal economic value of wind with increasing penetration is found to be largely a result of further reductions in capacity value. The energy value of wind is found to be roughly similar to the energy value of a flat block of power (and similar to the fuel and variable O&M cost of natural gas CCGT resources operating at full load). Only at very high penetration levels does the energy value of wind start to drop in the California case study presented here. Operational constraints cause some of the decline in the value of wind, but a large part of the decline in the value of wind is due to the merit-order impact of wind. The DA forecast error costs have little influence on the value of wind at low penetration and remain fairly manageable, on average less than $7/MWh, even at high penetration levels. AS costs are not found to have a large impact on the economic value of wind as modeled in this analysis.

- *At high penetration, the value of wind can exceed the value of PV and CSP without thermal storage:*

  While the marginal economic value of solar exceeds the value of wind at low penetration, at around 10% penetration the capacity value of PV and CSP_0 is found to be substantially reduced leading to the total marginal economic value of PV and CSP_0 being similar to the value of wind. At still higher penetrations, the energy value of PV and CSP_0 fall faster than the energy value of wind leading wind to have a higher marginal economic value than PV and CSP_0. CSP_6 on the other hand, is found to have a considerably higher value than wind at all penetration levels.

These results may, to a degree, be influenced by the fact that the analysis has loosely focused on California. In California, a region characterized by considerable natural gas fired generation, substantial hydropower generation, and diversity in potential wind resource sites, the dominant factors in understanding the economic value of wind and solar with increasing penetration levels are changes in the energy and capacity value of these sources. Analysis tools and methods for understanding economic value must therefore be able to adequately represent factors affecting resource adequacy and the merit-order stack of resources. Analysis, especially at high penetration, should also characterize conventional plant operational constraints like ramp-rates and start up costs. In regions outside of California that lack as much flexible gas and hydropower, consideration of operational constraints will be even more important.

Characterizing the impact of DA forecast errors and ancillary service requirements adds significant complexity to the analysis. Though the model used in this analysis relied on several simplifications, including commitment and dispatch decisions based on vintages rather than individual units and perfect foresight in the RT, the overall results indicate that the economic impact of DA forecast errors and AS requirements do not change as dramatically with increasing penetration and are a second order cost in the case of AS. That said, the actual amount of AS and the amount of flexibility required to manage DA forecast errors do increase with increasing VG penetration. Even though the economic impact may not be very large per unit of renewable energy, managing DA forecast errors and procuring adequate AS are both extremely important for ensuring system reliability and should continue to receive significant attention in studies of the steps necessary to ensure the technical feasibility of increasing variable generation penetrations.

One of the most important results from this work is the high capacity value of solar at low penetration and the decline in that capacity value (with the exception of CSP_6) with penetration levels around 10% on an energy basis. Given the importance of capacity value to the value of solar, areas of research that should be explored further include the ability of solar to contribute to resource adequacy, how that contribution changes with increasing penetration, and the economic implications of the decreasing contribution with increasing penetration. The capacity credit of PV and CSP_0 at increasing penetration levels should be investigated in more detail using detailed LOLP models to complement the less detailed, economic-focused analysis used here. In addition, as flexibility of generation resources becomes more important with increasing penetration of variable generation, methods to incorporate measures of flexibility into adequacy studies may also need to be developed. The capacity credit for CSP_6 should also be investigated further at high penetration levels. Based on the results presented here, however, energy constraints appear to impact the ability of CSP_6 to reduce the need for new generation capacity suggesting that methods used to evaluate the capacity credit of CSP_6 should be based on those suited to evaluating the capacity credit of resources in energy-constrained systems (e.g., methods used to evaluate resource adequacy in a system dominated by hydropower).

Another important finding of the present work is that the long-term value of adding TES to CSP is only obvious at higher penetration levels where the energy and capacity value of CSP_0 and PV fall off much faster than the value of CSP_6. Based on these results, TES should be especially considered by resource planners, solar manufacturers, and project developers for regions where the penetration of solar is expected to become substantial. Additional research is needed to assess whether this finding holds for power systems that differ from the one studied here. Research to explore the value of thermal storage in helping to manage DA forecast errors and AS increases caused by other VG technologies is also warranted.

Though this study focused on California and just one variable generation technology at a time, the same framework can be used to understand the economic value of variable generation in other regions and with different combinations of renewable energy. In a future report, the same framework will be used to evaluate how changes in the power system, like price responsive demand, more flexible thermal generation, and lower cost bulk power storage, might impact the value of variable generation. Each of these “mitigation strategies” might help slow the decline in the marginal economic value of variable generation found in this report. Ultimately, it is not possible to precisely know the long-run value of variable generation due to numerous sources of uncertainty, including future regulatory policies, future fuel prices, and future investment costs of conventional technologies. Analysis models like the one presented in this report, however, can help identify promising routes forward and inform decisions.

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Appendix A Overview of the Model

The appendix is structured as follows. Appendix A provides an overview of the model used in the analysis. Appendix B describes the general method used to find a set of conventional generation that leads to a long-run equilibrium. The method chooses different candidate sets of conventional generation that are then tested in the dispatch model, which is described in Appendix C. The parameters that are used in the model and additional detail on how the various parameters were estimated are in Appendix D. Finally, Appendix E includes the decomposition of the marginal economic value of variable generation with increasing penetration from each of the four sensitivity cases described in Section 5.4. The appendix is not a stand-alone document, rather it provides additional detail that supplements the main text.

The analysis of the long-run economic value of wind and solar in this report is based on an iterative search method that selects a candidate set of conventional generation resources and evaluates how those candidate resources perform over a full year of hourly dispatch and operations in a competitive electric power market with an exogenously set amount of variable generation (VG), namely wind or solar generation. The candidate set of generation can include both new investments in coal, combined-cycle gas turbines (CCGTs), simple cycle combustion turbines (CTs), or nuclear or existing thermal generation of the same type along with existing natural gas steam turbines and geothermal. Pumped hydro storage with 10 hours of storage capacity and an 81% round-trip efficiency can also be part of the candidate set of resources. Existing pumped hydro storage with the same characteristics as the new pumped hydro storage and existing hydro are assumed to not be able to be retired and are therefore always included in the model.

The overall objective is to find a portfolio of non-VG generation that is in long-run equilibrium for the given VG penetration. Long-run equilibrium means that the short-run profit earned by new generation in the portfolio is approximately equal to the fixed investment and fixed O&M cost of the generation and that the short-run profit earned by incumbent generation that remains in the portfolio is equal to or exceeds its fixed O&M cost. Short-run profit is defined as the total revenues earned over the year from the sale of energy and ancillary services less any variable costs (e.g., cost of fossil fuel, variable O&M, start-up costs, and carbon costs in the sensitivity scenario).

The method used to search for a portfolio of generation that is in long-run equilibrium is largely based on an approach that tests if the expected increase in short-run social surplus when generation capacity of a particular vintage is increased in the candidate set of generation exceeds the annualized investment cost of that generation capacity. Short-run social surplus is defined as the difference between the gross consumer surplus (the total economic benefit to consumers of consuming electricity irrespective of the cost of the electricity to consumers, or the area under the demand curve for all consumption) and all of the variable cost associated with producing electricity with a particular set of generation. In general, capacity is added when the expected increase in the social surplus exceeds the fixed cost. Generation capacity is removed if the savings from no longer paying for the fixed cost of that capacity is greater than the expected decrease in the short-run social surplus associated with the lower amount of available generation capacity. The selection of candidate sets of generators and the evaluation of the set in a power market continues until the set of generation cannot be improved upon using this search pattern. The search algorithm is based on insights from the Benders Decomposition method (Conejo et al., 2006).

In some cases this first search pattern fails to yield a solution where the short-run profits of any new generation is about equal to its annualized fixed costs. In this case the candidate set of generation is refined using various techniques, including the bisection method, to ensure that the short-run profit of new generation is approximately equal to its fixed cost. While this approach works for the specific objectives of this research, additional research on methods to identify portfolios of generation that are in long-run equilibrium while accounting for uncertainty between day-ahead and real-time markets is needed for more general studies.

The performance of a candidate set of generators in the power market is evaluated using a simplified, linear commitment and economic dispatch model. The power market is assumed to be composed of a two part day-ahead and real-time settlement process. The day-ahead commitment process determines how much of the thermal generation should be on-line in each hour, within operational constraints, based on the load, a deterministic day-ahead forecast of variable generation, and ancillary service requirements.

The real-time economic dispatch process then locks the day-ahead decision of how much generation is online in each hour for all thermal generators that cannot start within the hour (only CTs are modeled as quick start). The on-line capacity and quick start capacity are then dispatched within the operational constraints to meet the load, considering actual variable generation, and assumed ancillary service requirements. Hydro and storage resources are assumed to be able to be dispatched within the real-time market with perfect foresight. Unlike the treatment of variable generation forecast errors, load forecast errors are not explicitly included in this analysis. Instead, load forecast errors and generator outages are assumed to be handled through load-driven operating reserves in the ancillary service requirements.

The model used to evaluate the power market does not make commitment and dispatch decisions for individual generation units. Instead, generation resources with similar characteristics are grouped together as a generation vintage. Each vintage of generation is then dispatched as a single fleet of generation using linear dispatch constraints. Individual unit commitment would require integer variables rather than only linear variables in the dispatch problem which would greatly increase the complexity of the problem and increase the solution time. The linearization of commitment decisions using generation vintages is based on a similar approach used by Müsgens and Neuhoff (2006). The operational constraints for the vintages of thermal generation that are modeled in this way include start-up costs when the amount of on-line generation capacity increases, ramp-rate limits, minimum generation limits for on-line generation, and no-load fuel consumption for on-line generation. New generation resources are treated as separate new vintages with the amount of capacity in the vintage determined by the iterative search method summarized above and described in more detail in the pages that follow.

During challenging periods over the year, the generation resources may not be able to meet the ancillary service targets and load simultaneously either in the day-ahead or real-time process. The model is set up such that ancillary service targets are not met prior to involuntarily shedding load. In extreme cases, however, both ancillary service targets are not met and load is involuntarily shed. In hours when ancillary service targets are not fully met, the power market prices jump to high levels to indicate scarcity conditions. The highest that prices can go is assumed to be $10,000/MWh, which only occurs during times when load is assumed to be involuntarily shed. The power market is assumed to be an "energy-only" market such that high prices during periods of scarcity are used to cover the fixed investment cost of peaking plants (and contribute to covering a portion of the fixed investment cost of other generation) rather than relying on specific capacity obligations (Stoft, 2003; Hogan, 2005). The prices from the power market therefore reflect both the energy and capacity value of generation at any particular point of time throughout the year.

Appendix B Detailed Description of Investment Search Procedure

The power system planning and operations objective modeled in this paper is to maximize the gross economic value of consuming electricity while minimizing the investment and operating costs of electricity generation within dispatch constraints. As described later, this ideal situation is complicated by the inefficiency introduced between the day-ahead commitment of generation based on forecasts and the commitment that would have been made if there were no forecast errors. Ignoring forecast errors for now, the problem is summarized as:

$$\begin{aligned} \max_{\substack{(k_1 \ldots k_m) \\ (q_1^t \ldots q_m^t) \\ (l^t)}} \quad & \text{Social Surplus } (k_1 \ldots k_m, q_1^t \ldots q_m^t, l^t) - \sum_{g=1}^{m} FC_g k_g \\ \text{s.t.} \quad & \text{dispatch constraints} \end{aligned} \tag{3}$$

, where k is the capacity of a vintage of generation, q is the dispatch of the generation, and l is the load that is met by generation. The short-run social surplus is the difference between the total economic value of electricity to consumers (the gross consumer surplus, or the area under the demand curve for all consumption) and the variable cost of producing electricity for the generators (the variable production cost).[56] The power plants that generate electricity also have fixed costs (FC_g) including annual fixed maintenance and upkeep costs as well as capital costs for new power plants. These fixed costs are assumed to be proportional to nameplate capacity and are, in the model, annualized.[57]

B.1 Simplification of Investment and Operation Problem

This ideal power system planning objective cannot be directly solved due to the lack of perfect forecastability of variable generation between the day-ahead and real-time. Using insight from techniques used in Benders Decomposition (Cote and Laughton, 1979; Conejo et al., 2006, e.g.,), the challenge of determining the best choice of generator investments such that it maximizes the short-run social surplus less the fixed cost can be separated into two problems, the investment and the dispatch problem. All of the constraints related to dispatch of load and generation are contained in the dispatch problem, while decisions related to investment in capacity are contained in the investment problem. The imperfect forecastability of variable generation is included in the dispatch problem, which in turn impacts the selection of candidate generation portfolios in the investment problem. The investment problem becomes:

$$\max_{(k_1 \ldots k_m)} \quad \beta(k_1 \ldots k_m) - \sum_{g=1}^{m} FC_g k_g \tag{4}$$

The function, $\beta(k_1 \ldots k_m)$, is an unknown function that represents the dependence of the short-run social surplus on the choice of installed generation capacity. Specifically, function β is defined as:

[56] Short-run social surplus is an economic term in this context and is not meant to represent all potential costs and benefits to society related to the electric power system. We do not characterize the social costs of pollution, for example. A full societal cost benefit analysis of high penetrations of variable generation should consider these externalities, but is out of the scope of our analysis.

[57] Incumbent plants only have a fixed O&M component of FC_g without any fixed investment cost. In contrast to new investments, the nameplate capacity of incumbent generation chosen by the model, k_g, must be less than or equal to the nameplate capacity of the incumbent generation assumed in the model. As a result, "economic retirements" are implied when the model chooses less than the nameplate capacity of the incumbent generation, while retirements based simply on projected technical life are exogenously determined. The nameplate capacity constraints for incumbent capacity are included in the model but are not explicitly discussed here for clarity.

$$\beta(k_1 \dots k_m) \equiv \max_{\substack{(q_1^t \dots q_m^t) \\ (l^t)}} \quad \text{Social Surplus } (q_1^t \dots q_m^t, l^t)$$
$$\text{s.t.} \quad \text{dispatch constraints } (k_1 \dots k_m) \tag{5}$$

Even though the function β is unknown for all potential sets of generation, the function can be evaluated at specific points (i.e., specific candidate sets of generation capacity) by solving the maximization problem in Eq. 5 with a defined set of candidate generation capacity (which focuses only on operations or the dispatch of that generation). Solving the problem in Eq. 5 with a specific candidate set of generation capacity is described in more detail in Appendix C. Normal production cost models or unit-commitment and economic dispatch (UC/ED) models are designed to solve the problem in Eq. 5 with a given set of generators. The dispatch problem is therefore straightforward to evaluate with a specific set of generation using an appropriate dispatch model.

B.2 Approximation of the Investment Problem

The investment problem, on the other hand, is not as straightforward to evaluate since the function $\beta(k_1 \dots k_m)$ is unknown for all possible sets of generation. Since it is possible to evaluate $\beta(k_1 \dots k_m)$ at specific points using a candidate set of generation capacity in a dispatch model, however, the procedure for solving the investment problem involves approximating $\beta(k_1 \dots k_m)$ with an increasing number of planes that are tangent to the unknown function $\beta(k_1 \dots k_m)$ at the evaluated points (or with a candidate set of generation capacity). In more general terms, the unknown relationship between the social surplus and the choice of investment decisions is approximated by evaluating the social surplus in a dispatch model then estimating how the surplus would change with slightly different generator investments. The approximation of the function $\beta(k_1 \dots k_m)$ within the neighborhood of a particular set of generators, n, is denoted as $\beta^{(n)}(k_1 \dots k_m)$ and can be estimated as:

$$\beta^{(n)}(k_1 \dots k_m) \approx \text{Social Surplus}^{(n)} + \sum_{g=1}^{m} \frac{\partial \text{Social Surplus}^{(n)}}{\partial k_g} \left(k_g - k_g^{(n)} \right) \tag{6}$$

If the unknown function $\beta(k_1 \dots k_m)$ is concave, then the tangent planes that approximate $\beta(k_1 \dots k_m)$ will be greater than or equal to the actual unknown function. The function $\beta(k_1 \dots k_m)$ is approximated as the largest value β that is less than any of the tangent planes, $\beta^{(n)}(k_1 \dots k_m)$. The investment problem, Eq. 4, is then approximated as:

$$\begin{aligned}
\max_{\substack{(k_1 \dots k_m) \\ (\beta)}} \quad & \beta - \sum_{g=1}^{m} FC_g k_g \\
\text{s.t.} \quad & \beta \leq \text{ Social Surplus}^{(1)} + \sum_{g=1}^{m} \frac{\partial \text{Social Surplus}^{(1)}}{\partial k_g} \left(k_g - k_g^{(1)} \right) \\
& \beta \leq \text{ Social Surplus}^{(2)} + \sum_{g=1}^{m} \frac{\partial \text{Social Surplus}^{(2)}}{\partial k_g} \left(k_g - k_g^{(2)} \right) \\
\dots \quad & \\
& \beta \leq \text{ Social Surplus}^{(n)} + \sum_{g=1}^{m} \frac{\partial \text{Social Surplus}^{(n)}}{\partial k_g} \left(k_g - k_g^{(n)} \right)
\end{aligned} \tag{7}$$

, where Social Surplus$^{(n)}$ is the actual social surplus for a particular set of generators as found from a dispatch model. Each additional tangent plane or constraint in the investment problem leads to an evaluation of

$\beta(k_1 \ldots k_m)$ for a set of generators and a tightening of the estimate of the function that describes $\beta(k_1 \ldots k_m)$ for other potential sets of generators. Since the tangent planes are greater than $\beta(k_1 \ldots k_m)$, the actual unknown function is estimated "from above" as the estimate is tightened.

B.3 Estimating the Change in Social Surplus with Installed Capacity

The next challenge before being able to implement this simplification is to determine how to estimate the change in the social surplus with a change in generation capacity in the neighborhood of a particular set of generators. For a simple power system with perfectly flexible power plants that have constant marginal costs up to their generation capacity, it is straightforward to show (using the Karush-Kuhn-Tucker conditions) that the change in the social surplus with a slight increase in the capacity of a particular generator is based on the difference between the market clearing price (or the intersection of the demand curve and the generator supply function) and the marginal cost of the generator. In a simple system, the generator will be offline when the market clearing price is less than its marginal cost and at its full capacity when the market clearing price is above its marginal cost. It can then be shown that the short-run profit ($SR_{\pi,i}$) earned by a generator that is paid the market clearing price is equivalent to the change in the social surplus with a small change in the amount of installed capacity.

In the more general case, the change in the social surplus with a change in capacity is only approximated by the short-run profit earned by a generator where generators are paid the market clearing price. The short-run profit of the generator is estimated using the dispatch and price results from simulating a particular set of generation in the dispatch model used to calculate the social surplus for a particular set of generation.

The investment problem can therefore be approximated as:

$$\begin{aligned} \max_{\substack{(k_1 \ldots k_m) \\ (\beta)}} \quad & \beta - \sum_{g=1}^{m} FC_g k_g \\ \text{s.t.} \quad & \beta \leq \text{ Social Surplus}^{(n)} + \sum_{g=1}^{m} SR_{\pi,i}^{(n)} \left(k_g - k_g^{(n)}\right) \quad \forall n \in 1 \ldots \nu - 1 \end{aligned} \tag{8}$$

B.3.1 Convergence Criteria

With additional estimates of the tangent planes evaluated with a specific set of generators, the simplified maximization problem in Eq. 8 will be an increasingly accurate representation of the full optimization problem in Eq. 3. Since each set of generators evaluated in the simplified maximization problem in Eq. 8 adds tangent planes that are 'above' the true unknown function representing the real-time surplus as a function of generation capacity, $\beta(k_1 \ldots k_m)$, the upper bound to the full optimization problem in Eq. 3 is given by:

$$\text{UB}^{(n+1)} = \beta^{(n)} - \sum_{g=1}^{m} FC_g k_g^{(n+1)} \tag{9}$$

For any candidate set of generators, the true maximum real-time surplus with those generators can be calculated using a dispatch model. Because the candidate set of generators will not necessarily be the optimal generators that would be calculated in the full optimization problem in Eq. 3, the lower bound is given by:

$$\text{LB}^{(n+1)} = \text{Social Surplus}^{(n+1)} - \sum_{g=1}^{m} FC_g k_g^{(n+1)} \tag{10}$$

A sufficient number of candidate sets of generators have been evaluated to create an adequate approximation when the upper and lower bounds converge within some convergence criteria, ϵ.[58]

[58] Typically the convergence criteria used in this report was 2×10^{-8} times the upper bound.

B.4 Implementation

In sum, the original problem Eq. 3 is approximated by the following procedure, starting first with an excess of generation capacity in the candidate set of generator investments:

1. Determine the optimal commitment and dispatch of the chosen set of generation in a dispatch model.
2. Calculate the optimal social surplus for the set of generation (Social Surplus$^{(n)}$) and estimate the change in social surplus with a change in generation capacity as the short-run profits of the generation.
3. Check to see if the current approximation of the social surplus function, $\beta(k_1 \ldots k_m)$ is adequate, (i.e. is $\text{UB} - \text{LB} < \epsilon$).
   - If it is adequate, stop: the current set of generation and the dispatch is the best estimate of the solution to Eq. 3.
   - If it is not adequate: continue.
4. Use the results of the dispatch model with the current set of generation to create an additional tangent plane to the social surplus function, $\beta(k_1 \ldots k_m)$. Add the tangent plane as a new constraint in the investment problem, Eq. 8.
5. Solve the investment problem with the n sets of tangent planes to determine the $n+1$ set of generators.
6. Return to Step 1 with the new set of generators.

This iterative procedure, which passes a candidate set of generators into the dispatch problem then uses the results of the dispatch problem to generate a new constraint in the investment problem, usually leads to an adequate approximation of the social surplus function, $\beta(k_1 \ldots k_m)$. The set of generators and their dispatch in the final run of the dispatch model is the best approximation of the solution to Eq. 3 and usually leads to a candidate set of generation that is in long-run equilibrium.

In practice, the investment problem did not always converge in the expected manner, likely due to differences between the simplified generators used in the derivation of the search procedure and the complexity of the operational constraints associated with the actual generator vintages modeled for this paper and due to the complexity associated with the uncertainty between the day-ahead and real-time. In these cases, the iterations were stopped when the iteration procedure could no longer improve upon the current set of generators, and alternative techniques were then used to refine the set of generation. The main alternative technique that was used was the bisection method. The objective of the bisection method was to adjust the capacity of the lowest fixed cost generation until the short-run profit of that generator was approximately equal to its fixed costs. Alternatively manual adjustment of the candidate set was made in order to find a candidate set of generation that was in long-run equilibrium. Usually only slight adjustments needed to be made.

Appendix C Commitment and Dispatch Model Formulation

The commitment and economic dispatch model maximizes the social surplus over a year with hourly time steps given a particular choice of generation investments, which in simplified form is represented by:

$$\text{Social Surplus}^{(n)}(k_1^{(n)} \dots k_m^{(n)}) \equiv \max_{\substack{(q_1^t \dots q_m^t) \\ (l^t)}} \quad \text{Social Surplus } (q_1^t \dots q_m^t, l^t)$$
$$\text{s.t.} \quad \text{dispatch constraints } (k_1^{(n)} \dots k_m^{(n)}) \tag{11}$$

This section summarizes the formal method for estimating the social surplus and defines the assumed dispatch constraints.

Overall, the day-ahead commitment model is used to generate day-ahead commitment, day-ahead generation schedules, and day-ahead prices for energy and ancillary services. The day-ahead decisions are made using day-ahead forecasts for wind and solar generation and perfectly accurate load forecasts. The commitment formulation largely follows approaches used by Sioshansi and Short (2009) and Müsgens and Neuhoff (2006). In contrast to the simplifications used here, the CAISO uses a much more detailed unit-specific unit-committment model in its DA and RT market. The basic principal of solving a commitment model to determine generation schedules and deriving prices for energy and ancillary services using the shadow value of the load balance and reserve target constraints, respectively, is similar to the way the CAISO market is operated (California ISO (CAISO), 2009).

The problem nomenclature is as follows:

Problem Parameters

- General:
  - M: number of months in a year
  - T: number of hours, t, in a month
  - I: conventional generation vintage index set
  - V: variable generation vintage index set
- Conventional generation:
  - $VC_i(q)$: generator $i \in I$ convex piecewise-linear variable cost function
  - N_i: generator vintage $i \in I's$ no-load cost
  - SU_i: generator vintage $i \in I's$ startup cost
  - K_i^+: generator vintage $i \in I's$ nameplate capacity
  - α_i^{min}: generator vintage $i \in I's$ minimum generation as a fraction of online generation
  - α_i^{qs}: generator vintage $i \in I's$ quick start availability for non-spinning reserves (1 for quick-start capacity, 0 for other capacity)
  - RR_i: generator vintage $i \in I's$ ramp rate capability per hour
- Variable generation:
  - K_ν^+: nameplate capacity of variable generator vintage $\nu \in V$
  - $CF_{\nu,t}^f, CF_{\nu,t}^a$: forecast and actual hourly variable generation in hour $t \in T$ from variable generator $\nu \in V$ as percentage of nameplate capacity
- Hydropower and pumped hydro storage:

- $E_{hy,m}$: hydropower energy budget for each month $m \in M$
- K_{hy}^{+}: nameplate capacity of hydropower generation vintage
- $K_{hy,m}^{-}$: minimum hydropower generation rate in each month $m \in M$
- K_{pc}^{+}: nameplate capacity of pumped hydro storage power converter
- K_{pr}^{+}: capacity of storage reservoir in number of hours at full converter output
- ξ^{in}: efficiency of storage while pumping water into storage
- ξ^{out}: efficiency of storage while converting discharging water into electricity

- Demand, reserves, and virtual load:
  - $p_t(l)$: non-increasing stepped inverse demand function in hour $t \in T$, with an assumed price cap at the value of lost load (VOLL)
  - $\eta^{ns}, \eta^{s,l}, \eta^{r,l}$: nonspinning, spinning, and regulation reserve requirements as a fraction of hourly load
  - $\eta^{ns,\nu}, \eta^{s,\nu}, \eta^{r,\nu}$: non-spinning, spinning and regulation reserve requirements as a fraction of scheduled hourly variable generation
  - $\eta^{vl,\nu}$: Virtual load bid in the day-ahead market as a fraction of the scheduled hourly variable generation
  - $\eta^{vl,l}$: Virtual load bid in the day-ahead market as a fraction of the load
  - $\tau_{ns}, \tau_{sp}, \tau_{r}$: fraction of an hour by which (1) non-spinning reserve, (2) spinning reserve, and (3) regulation reserves need to be fully available
  - P^r, P^s, P^{ns}: assumed loss of social welfare per unit of regulation, spinning, and nonspinning reserve not procured (loss of social welfare declines with lower quality reserves)

Decision Variables

- Conventional generation:
  - $q_{i,t}$: generation provided by generator $i \in I$ in hour $t \in T$
  - $u_{i,t}$: generation online and spinning by generator $i \in I$ in hour $t \in T$
  - $s_{i,t}, d_{i,t}$: variables indicating if generating unit $i \in I$ started up or shut down in hour $t \in T$, respectively
  - $r_{i,t}^{+}, r_{i,t}^{-}$: regulation up reserves and regulation down reserves provided by generator $i \in I$ in hour $t \in T$
  - $sp_{i,t}, nsu_{i,t}, nsd_{i,t}$: spinning and nonspinning (from online (u) or offline (d) generation) reserves provided by generator
- Variable generation:
  - $q_{\nu,t}$: variable generation for $\nu \in V$ scheduled in hour $t \in T$
  - $r_{\nu,t}^{-}$: regulation down reserve provided by variable generator $\nu \in V$ in hour $t \in T$
- Hydropower and storage:
  - $q_{hy,t}$: hydropower generation scheduled in hour $t \in T$
  - $q_{spill,t}$: hydropower generation spilled in hour $t \in T$
  - $q_{p,t}^{in}$: pumped hydro storage pumping load in hour $t \in T$
  - $q_{p,t}^{out}$: pumped hydro storage generation in hour $t \in T$

- e_t: energy in pumped hydro storage reservoir in hour $t \in T$
- $r^+_{hy,t}, r^+_{p,t}$: regulation up reserve provided by hydropower, pumped hydro storage in hour $t \in T$
- $r^-_{hy,t}, r^-_{p,t}$: regulation down reserve provided by hydropower, pumped hydro storage in hour $t \in T$
- $sp_{hy,t}, sp_{p,t}$: spinning reserve provided by hydropower, pumped hydro storage in hour $t \in T$
- $ns_{hy,t}, ns_{p,t}$: non-spinning reserve provided by hydropower, pumped hydro storage in hour $t \in T$

- Demand, reserves:
  - $r^-_{P,t}, r^+_{P,t}$: regulation up and regulation down reserve target not met in hour $t \in T$
  - $sp_{P,t}, ns_{P,t}$: spinning and nonspinning reserve target not met in hour $t \in T$
  - l_t: load served in hour $t \in T$

Dual variables

- λ_t: load balance constraint in hour $t \in T$ (energy price)
- $\lambda_{ns,t}$: nonspinning reserve constraint in hour $t \in T$ (nonspinning reserve price)
- $\lambda_{s,t}$: spinning reserve constraint in hour $t \in T$ (spinning reserve price)
- $\lambda_{r^+,t}$: regulation up reserve constraint in hour $t \in T$ (regulation up reserve price)
- $\lambda_{r^-,t}$: regulation down reserve constraint in hour $t \in T$ (regulation down reserve price)

Day ahead problem formulation:

The objective function for each month is:

$$\max \quad \text{Social Surplus} =$$
$$\sum_t \int_0^{l_t} p_t(x)dx - \sum_t \left(\sum_i \left(VC(q_{i,t}) + N_i u_{i,t} + SU_i s_{i,t}\right) + P^r(r^-_{P,t} + r^+_{P,t}) + P^s sp_{P,t} + P^{ns} ns_{P,t}\right)$$

subject to the following system operational constraints:

- load-balance $(\forall t \in T), \lambda_t$:

$$\sum_i q_{i,t} + \sum_\nu q_{\nu,t}\left(1 - \eta^{vl,\nu}\right) + q_{hy,t} + q^{out}_{p,t} = l_t\left(1 - \eta^{vl,l}\right) + q^{in}_{p,t}$$

- nonspinning reserve target $(\forall t \in T), \lambda_{ns,t}$:

$$\sum_i (nsu_{i,t} + nsd_{i,t}) + ns_{hy,t} + ns_{p,t} + ns_{P,t} \geq \eta^{ns} l_t + \eta^{ns,\nu} CF^f_{\nu,t} K^+_\nu$$

- spinning reserve target $(\forall t \in T), \lambda_{s,t}$:

$$\sum_i sp_{i,t} + sp_{hy,t} + sp_{p,t} + sp_{P,t} \geq \eta^{s,l} l_t + \eta^{s,\nu} CF^f_{\nu,t} K^+_\nu$$

- regulation up reserve target $(\forall t \in T), \lambda_{r^+,t}$:

$$\sum_i r^+_{i,t} + r^+_{hy,t} + r^+_{p,t} + r^+_{P,t} \geq \eta^{r,l} l_t + \eta^{r,\nu} CF^f_{\nu,t} K^+_\nu$$

- regulation down reserve target ($\forall t \in T$), $\lambda_{r^-,t}$:

$$\sum_i r^-_{i,t} + \sum_\nu r^-_{\nu,t} + r^-_{hy,t} + r^-_{p,t} + r^-_{P,t} \geq \eta^{r,l} l_t + \eta^{r,\nu} CF_{\nu,t} K^+_\nu$$

and the following conventional generator constraints ($\forall i \in I, t \in T$):

- minimum generation constraint

$$\alpha_i^{min} u_{i,t} \leq q_{i,t} - r^-_{i,t}$$

- generation total capacity constraint

$$u_{i,t} + nsd_{i,t} \leq K^+_i$$

- generation from spinning plant

$$q_{i,t} + r^+_{i,t} + sp_{i,t} + nsu_{i,t} \leq u_{i,t}$$

- generation nonspinning reserve from on-line plant capability

$$0 \leq nsu_{i,t} \leq u_{i,t} RR_i \tau_{ns}$$

- generation nonspinning reserve from quick-start plant capability

$$0 \leq nsd_{i,t} \leq K^+_i \alpha^{qs}_{i,t}$$

- generation spinning reserve capability

$$0 \leq sp_{i,t} \leq u_{i,t} RR_i \tau_{sp}$$

- generation regulation up capability

$$0 \leq r^+_{i,t} \leq u_{i,t} RR_i \tau_r$$

- generation regulation down capability

$$0 \leq r^-_{i,t} \leq u_{i,t} RR_i \tau_r$$

- generation ramp down capability

$$q_{i,t-1} - q_{i,t} + r^-_{i,t} \leq u_{i,t-1} RR_i$$

- generation ramp up capability

$$q_{i,t} - q_{i,t-1} + r^+_{i,t} + sp_{i,t} + nsu_{i,t} \leq u_{i,t-1} RR_i$$

- generation start up and shut down transition

$$u_{i,t} = u_{i,t-1} + s_{i,t} - d_{i,t}$$

and subject to variable generation constraints ($\forall \nu \in V, \forall t \in T$)

- variable generation capacity

$$0 \leq q_{\nu,t} + r^{-}_{\nu,t} \leq K^{+}_{\nu} CF^{f}_{\nu,t}$$

- variable generation regulation down capability

$$0 \leq q_{\nu,t} - r^{-}_{\nu,t}$$

and subject to hydro generation constraints

- hydropower generation monthly energy budget

$$\sum_{t} q_{hy,t} + q_{spill,t} \leq E_{hy,m}$$

- minimum hydropower generation rate ($\forall t \in T$)

$$q_{hy,t} - r^{-}_{hy,t} + q_{spill,t} \geq K^{-}_{hy,m}$$

- hydropower capacity limit ($\forall t \in T$)

$$q_{hy,t} + r^{+}_{hy,t} + sp_{hy,t} + ns_{hy,t} \leq K^{+}_{hy}$$

and subject to pumped hydro storage constraints ($\forall t \in T$):

- storage inventory

$$e_t = e_{t-1} + q^{in}_{p,t} \xi^{in} - \frac{q^{out}_{p,t}}{\xi^{out}}$$

- storage reservoir capacity

$$e_t \leq K^{+}_{pc} K^{+}_{pr}$$

- storage converter capacity limit for generation

$$q^{out}_{p,t} + r^{+}_{p,t} + sp_{p,t} + ns_{p,t} \leq K^{+}_{pc}$$

- storage converter capacity limit for pumping (storing)

$$q^{in}_{p,t} + r^{-}_{p,t} \leq K^{+}_{pc}$$

Once a solution is found for the DA commitment problem, the online generation variable $u_{i,t}$ can be fixed for plants that cannot change their commitment decisions in the real-time market. The day-ahead problem is run for an entire month so that unit-commitment schedules reflect the generation of hydropower (which is constrained to generate only a given amount each month).

For the real-time problem, the same dispatch problem with a few key changes is solved again. The changes include the following: a constraint is added that fixes the commitment of the slow start units based on the day-ahead commitment schedule of those units, virtual load is set to zero ($\eta^{vl,\nu} = 0$ in real-time), and the day-ahead forecast of variable generation (CF^f_ν) replaced with the actual realized generation (CF^a_ν) in the variable generation capacity constraint. Note that the anciallary service requirements are maintainted in both the DA and RT as the anciallry service requirements are based on sub-hourly variation and contingencies, both factors that are not explicitly modeled in the real-time problem with hourly intervals. The results from each month are then put together to form the schedules and dispatch over the entire year.

The results of the commitment and economic dispatch over the entire year are then used to calculate the short-run profits of each generator as:

$$SR_{\pi,i} = SR^{\mathrm{DA}}_{\pi,i} + SR^{\mathrm{RT}}_{\pi,i}$$

The day-ahead short-run profit is simply the day-ahead schedule times the day-ahead price premium over the real-rime price. The real-time short-run profit is the difference between the real-time price and the actual real-time generating costs:

$$\begin{aligned}
SR^{\mathrm{DA}}_{\pi,i} \quad = \quad & (\sum_t \left(\lambda^{\mathrm{DA}}_t - \lambda^{\mathrm{RT}}_t\right) q^{\mathrm{DA}}_{i,t} \\
& + \left(\lambda^{\mathrm{DA}}_{ns,t} - \lambda^{\mathrm{RT}}_{ns,t}\right) \left(nsu^{\mathrm{DA}}_{i,t} + nsd^{\mathrm{DA}}_{i,t}\right) \\
& + \left(\lambda^{\mathrm{DA}}_{s,t} - \lambda^{\mathrm{RT}}_{s,t}\right) sp^{\mathrm{DA}}_{i,t} \\
& + \left(\lambda^{\mathrm{DA}}_{r^+,t} - \lambda^{\mathrm{RT}}_{r^+,t}\right) r^{+,\mathrm{DA}}_{i,t} \\
& + \left(\lambda^{\mathrm{DA}}_{r^-,t} - \lambda^{\mathrm{RT}}_{r^-,t}\right) r^{-,\mathrm{DA}}_{i,t})/K^+_i
\end{aligned}$$

$$\begin{aligned}
SR^{\mathrm{RT}}_{\pi,i} \quad = \quad & (\sum_t \lambda^{\mathrm{RT}}_t - VC(q^{\mathrm{RT}}_{i,t}) - N_i u^{\mathrm{RT}}_{i,t} - SU^{\mathrm{RT}}_i s_{i,t} \\
& + \lambda^{\mathrm{RT}}_{ns,t}(nsu^{\mathrm{RT}}_{i,t} + nsd^{\mathrm{RT}}_{i,t}) + \lambda^{\mathrm{RT}}_{s,t} sp^{\mathrm{RT}}_{i,t} \\
& + \lambda^{\mathrm{RT}}_{r^+,t} r^{+,\mathrm{RT}}_{i,t} + \lambda^{\mathrm{RT}}_{r^-,t} r^{-,\mathrm{RT}}_{i,t})/K^+_i
\end{aligned}$$

If the convergence criteria of the investment problem have not been met, the short-run profits for each generation vintage in the candidate set of generation and the social surplus from the real-time market are then used in the investment problem to create an additional tangent line constraint for the problem in Eq. 8. The investment problem is run again with the new constraint to determine the next set of candidate conventional generators to test in the commitment and dispatch model. This process is repeated in an iterative manner until the investment model chooses the installed capacity that meets the convergence criteria described in Appendix B.

Appendix D Model Parameters

The parameters for thermal generation, hydropower generation, and pumped hydro storage described in the Data and Assumptions section of the report are summarized in this appendix. The parameters include the definition of 17 thermal generator vintages (Table 12), the assumed technical life retirement age in the Reference scenario (Table 13), the incumbent generation in the "No Retirements" scenario and the resulting incumbent generation with the assumed technical life in the Reference scenario (Table 14), and the assumed thermal plant generation characteristics (Table 15, Table 16, and Table 17). Assumptions for the emissions (Table 18, Table 19, and Table 20) and fixed and variable cost of thermal plants (Table 21) are also described. Finally, this section summarizes the fuel cost assumptions (Table 22), the assumed monthly hydropower constraints (Table 23) and the assumed parameters for pumped hydro storage (Table 24).

The thermal generation assigned to the California NERC sub-region were grouped into 17 vintages described in Table 12. The separation of the generation into different vintages was based on an examination of plant heat rate, ramp rate, and pollution generation characteristics. The categories used for separating the plant characteristics were type of prime mover, type of fuel, size of plant, and plant online date.

Table 12: Thermal generator vintage definitions

Generation Vintage	Prime Mover	Fuel	Capacity Range (MW)	Online Date
Coal_ST_Big	Steam Turbine	Coal	≥ 800	Any
Coal_ST_Small_New	Steam Turbine	Coal	< 200	≥ 1980
Coal_ST_Small_Old	Steam Turbine	Coal	< 200	< 1980
Gas_ST_Big	Steam Turbine	Gas	≥ 400	Any
Gas_ST_Mid_New	Steam Turbine	Gas	200-400	≥ 1965
Gas_ST_Mid_Old	Steam Turbine	Gas	200-400	< 1965
Gas_ST_Small_New	Steam Turbine	Gas	< 200	≥ 1965
Gas_ST_Small_Old	Steam Turbine	Gas	< 200	< 1965
Gas_CC_Big	Combined Cycle	Gas	≥ 800	Any
Gas_CC_Mid_New	Combined Cycle	Gas	200-800	≥ 1995
Gas_CC_Mid_Old	Combined Cycle	Gas	200-800	< 1995
Gas_CC_Small_New	Combined Cycle	Gas	< 200	≥ 1980
Gas_CC_Small_Old	Combined Cycle	Gas	< 200	< 1980
Gas_CT_New	Combustion Turbine	Gas	Any	≥ 1980
Gas_CT_Old	Combustion Turbine	Gas	Any	< 1980
Geothermal	Steam Turbine	-	Any	Any
Nuclear	Steam Turbine	Uranium	Any	Any

A plant technical life was used to estimate the amount of generation that would still be in service in 2030, Table 13. The technical life of coal and natural gas steam plants is based on an analysis of historic plant retirement ages in North America using the Ventyx Velocity Suite database of plant ages and retirement dates and similar assumptions used in other studies (IEA, 2010; Sims et al., 2007). Fewer retirements of CT and CCGTs were available from the historic Ventyx data, and instead a technical life of 30 years was assumed based on the technical life presented by IEA (2011). The technical life for nuclear plants is based on an original license life of 40 years with a single 20-year license renewal. A similar assumption was used in the 2010 EIA Annual Energy Outlook Alternative Nuclear Retirement Case (EIA, 2010). Hydro plants are assumed to never retire.

The amount of incumbent generation in the California NERC sub-region was estimated using the assumptions of the plant technical life and the online date of the thermal generation, Table 14. In the "No Retirements" sensitivity scenario, all of the current generation capacity was assumed to still be available in 2030.

Table 13: Retirement age assumed for different plant types in the Reference scenario

Plant Type	Assumed Retirement Age (years)
Combustion Turbine	30
Combined Cycle	30
Steam	50
Nuclear	60
Hydro	None

Table 14: Incumbent generator capacity in California NERC sub-region for 2030.

Generation Vintage	Incumbent Generation Capacity (GW)	
	Reference	No Retirement
Coal_ST_Big	1.8	1.8
Coal_ST_Small_New	0.4	0.4
Coal_ST_Small_Old	0	0.1
Gas_ST_Big	0	6.2
Gas_ST_Mid_New	0	1.9
Gas_ST_Mid_Old	0	5.3
Gas_ST_Small_New	0.1	0.2
Gas_ST_Small_Old	0	2.4
Gas_CC_Big	1.8	1.8
Gas_CC_Mid_New	13.1	13.1
Gas_CC_Mid_Old	0	1.0
Gas_CC_Small_New	1.2	2.0
Gas_CC_Small_Old	0	2.0
Gas_CT_New	4.0	7.3
Gas_CT_Old	0	0.4
Geothermal	1.7	2.1
Nuclear	4.6	4.6
Hydropower	13.3	13.3
Pumped Hydro Storage	3.5	3.5
Total Incumbent	45.5	69.4

Several thermal generator operating characteristics were quantified for each vintage using all of the thermal generation resources in WECC that are characterized in the Ventyx database, Table 15. These parameters include the following:

- No-load heat rate: hypothetical amount of fuel that would be burned if the thermal plant were online but producing no electricity (in reality thermal generators have a minimum generation constraint that would force the plant to produce some electricity whenever it is online).
- Start-up heat: fuel that is consumed during each start-up of the thermal plant without producing electricity.
- Non-fuel start-up cost: wear & tear and related costs associated with starting a thermal plant. Ventyx does not report this cost. Instead these costs were estimated from non-fuel start-up costs used in WECC transmission modeling (WECC, 2011).
- Minimum generation rate: the percentage of the nameplate capacity that the plant must be above in order to remain online and generate electricity.
- Ramp-rate: the maximum rate at which generation can change its output in the up or down direction as a percentage of the online generation.
- Quick-start: only quick start plants can change the amount of generation that is online in each hour. The day-ahead decisions for the amount of generation that will be online in any hour is binding for the remaining non-quick-start generation.

Geothermal and nuclear vintages were assumed to be inflexible and operated at load throughout the year (also these plants are not characterized by the Ventyx database because there are no air emissions from these plants that would be monitored with the EPA CEMS program).

Where Ventyx data were used to estimate the parameters for the other generation, the generating characteristics of each vintage were estimated by averaging detailed unit-specific estimates of individual unit generation operating parameters for existing conventional generation in WECC of the same vintage-type. The individual unit characteristics were reported in the Ventyx EV Market-Ops, Unit Capacity Blocks & Ramprates table. The Ventyx data is largely based on historic plant operations derived from US EPA CEMS data. Since the unit-specific values are averaged across plants and are based on historic plant performance, these generator parameters reflect current plant operation. The plants may technically be able to provide more flexibility than they have historically provided. The parameters used in this study will therefore tend to understate the flexibility of conventional generation.

In addition to the existing generation in WECC, the new investment options were assumed to have operational and emission characteristics similar to recent vintages. The generation vintages that can be built by the model have the prefix "Invest_" before the vintage name in the tables.

Ramp-rates for the CT vintage were found to be very low when using hourly data from the Ventyx dataset. In addition the Ventyx dataset does not include ramp-rates for hydro nor does Ventyx report non-fuel start-up costs. The ramp-rates for the CT vintage and for hydropower[59] along with the non-fuel start-up costs related to wear & tear for all thermal plants are therefore derived from the assumptions used in WECC transmission modeling (WECC, 2011). Ramp-rates and non-fuel start-up costs are listed for individual units in the database listing WECC assumptions used in transmission modeling. The CT ramp-rates are based on a linear fit between individual unit capacity and individual unit ramp-rate in MW/hr. Only those individual units whose ramp-rates fell near a pronounced linear relationship between ramp rate and capacity were used since there was significant scatter between ramp-rate and capacity for a number of units. The non-fuel start-up costs for steam plants (coal and natural gas), CCGTs, and CTs were similarly derived from the database of WECC transmission modeling assumptions by applying a linear fit between non-fuel start-up cost and

[59]The ramp-rates used here are more conservative than the ramp-rates that are reported for CTs and aggregated hydropower plants by (Makarov et al., 2008). This lower bound on ramp rate capabilities helps to reduce any bias that would otherwise be introduced by the fact that this study does not include any costs associated with ramping plants.

individual unit capacity. Most of the start-up costs fell along a line and relatively few units clearly did not fall onto the same line as the other units. The linear relationship was used to apply a non-fuel startup cost to the different vintages depending on the capacity range of the vintage. In $/MW-start terms, the non-fuel startup costs for CCGTs and CTs were similar, with CTs having a slightly higher cost. The start-up costs for steam plants were clearly lower than the start-up costs for CTs and CCGTs across all individual unit capacities.

The non-fuel start-up costs for coal plants derived from the WECC assumptions are similar to the warm start costs (i.e., the plant is not down for longer than 120 hours) for coal plants reported by Gray (2001). More recent preliminary research on average "lower-bound" start-up costs for coal, natural gas steam turbines, CCGT, and CT plants by Intertek Aptech shows that the range of start-up costs from actual plants may be somewhat higher for coal plant and lower for CT plants than the assumed average costs used in this analysis (Lefton, 2011). As non-fuel start-up costs are an area of ongoing research, this is an area where assumptions should be revisited as more detailed estimates become available.

Table 15: Thermal generator no-load heat, start-up heat and non-fuel cost, minimum generation, and ramp rate. Source: Derived from Ventyx except where noted otherwise.

Generation Vintage	No-load Heat (MMBtu/ MW-h)	Start-up Heat (MMBtu/ MW-start)	Non-fuel [a] Start-up Cost ($/MW-start)	Minimum Generation (% rated capacity)	Ramp Rate (% per hour)	Quick[b] Start
Coal_ST_Big	2.4	20.6	8	50	25	0
Coal_ST_Small_New	1.8	17.7	14	50	33	0
Coal_ST_Small_Old	0.8	17.8	14	45	33	0
Gas_ST_Big	0.6	11.4	9	25	37	0
Gas_ST_Mid_New	0.5	15.6	10	27	44	0
Gas_ST_Mid_Old	0.6	14.8	10	27	47	0
Gas_ST_Small_New	0.5	11.3	14	30	38	0
Gas_ST_Small_Old	0.7	18.1	14	31	46	0
Gas_CC_Big	1.4	5.0	56	25	24	0
Gas_CC_Mid_New	1.2	7.8	56	29	39	0
Gas_CC_Mid_Old	0.6	11.7	56	27	60	0
Gas_CC_Small_New	1.1	9.0	57	35	40	0
Gas_CC_Small_Old	2.2	20.7	57	41	38	0
Gas_CT_New	1.8	10.0	86	43	197[a]	1
Gas_CT_Old	2.9	16.2	86	52	197[a]	1
Geothermal[c]	2.4	n/a	n/a	100	n/a	0
Nuclear[c]	2.4	n/a	n/a	100	n/a	0
Invest_Nuclear[c]	2.4	n/a	n/a	100	n/a	0
Invest_Gas_CC_Mid_New	1.2	7.8	56	29	39	0
Invest_Coal_ST_Mid_New	0.7	21.9	14	48	22	0
Invest_Gas_CT_New	1.8	10.0	86	43	197	1

a - Derived from WECC assumptions (WECC, 2011)
b - 1 for units that can be committed in real-time, 0 otherwise
c - assumed to operate at full load at all time

Several thermal generation parameters vary depending on the loading of the vintage. These parameters are described for each vintage with constant rates within each of four loading blocks, Table 16. The first block starts at the minimum generation level and increases up to the second block (Block 0, which occurs between 0% generation and minimum generation is not a feasible state for generation). The fourth block describes the parameters for the thermal generation at full load.

Table 16: Thermal generator lower limit block defintions. Source: Derived from Ventyx

Generation Vintage	Block 1 (% rated capacity)	Block 2 (% rated capacity)	Block 3 (% rated capacity)	Block 4 (% rated capacity)
Coal_ST_Big	50	67	83	100
Coal_ST_Small_New	50	67	83	100
Coal_ST_Small_Old	45	63	81	100
Gas_ST_Big	25	50	75	100
Gas_ST_Mid_New	27	51	76	100
Gas_ST_Mid_Old	27	51	75	100
Gas_ST_Small_New	30	53	76	100
Gas_ST_Small_Old	31	53	76	100
Gas_CC_Big	25	50	75	100
Gas_CC_Mid_New	29	53	76	100
Gas_CC_Mid_Old	27	51	76	100
Gas_CC_Small_New	35	56	78	100
Gas_CC_Small_Old	41	60	80	100
Gas_CT_New	43	61	80	100
Gas_CT_Old	52	67	84	100
Geothermal	100	100	100	100
Nuclear	100	100	100	100
Invest_Gas_CC_Mid_New	29	53	76	100
Invest_Coal_ST_Mid_New	48	66	83	100
Invest_Gas_CT_New	43	61	80	100
Invest_Nuclear	100	100	100	100

In addition to the fuel consumed in start-up and the no-load fuel consumption, increasing the amount of electricity produced by a thermal plant increases the amount of fuel burned. The incremental increase in fuel consumption for an increase in electricity production is shown for the four blocks in Table 17 based on Ventyx data. The incremental heat rate is non-decreasing with increases in loading of the online generation. The natural gas fired steam vintages appear to have the greatest increase in heat rate with higher loading. On the other hand, the average heat rate, which includes both the incremental fuel consumption and the no-load heat, decreases with increases in loading.

The CO_2 emissions from the thermal plants are assumed to be proportional to the fuel consumed (note that this is not equivalent to being proportional to the electricity generated due to part-load inefficiencies and start-up emissions). The emissions of NO_x and SO_2 are not proportional to fuel consumption. In fact, in some cases the emissions due to start-up on a per unit of fuel basis can be much greater than the hourly emissions expected for an on-line plant. The start-up emissions for thermal plants are not included in the Ventyx database. The NO_x and SO_2 emissions during start-up are therefore assumed to be proportional to the hourly full-load emissions of the vintage based on detailed analysis of start-up emissions in Lew et al. (2011), Table 18. Based on that analysis the ratio of the NO_x emissions due to start-up to the hourly NO_x emissions from a fully-loaded CCGT was 9.5, from a fully loaded CT was 6.7, and from a fully-loaded coal plant was 2.9. Additionally, they found that the ratio of the SO_2 emissions due to start-up to the hourly SO_2 emissions from a fully-loaded coal plant was 2.7. They do not report the ratio of the SO_2 emissions due to start-up to the hourly SO_2 emissions for a fully loaded CCGT or CT plant. In this analysis we therefore assume that the ratio for CCGTs and CTs is the same ratio reported for coal.

The assumed average NO_x emissions rate for thermal generation depending on the load factor is derived

Table 17: Thermal generator incremental marginal heat rate.[a] Source: Derived from Ventyx

Generation Vintage	Marginal Heat Rate (MMBtu/MWh) Block 1	Block 2	Block 3	Block 4
Coal_ST_Big	8.0	8.1	8.1	8.1
Coal_ST_Small_New	10.5	10.5	10.5	10.5
Coal_ST_Small_Old	10.9	10.9	10.9	10.9
Gas_ST_Big	9.2	9.3	9.4	9.5
Gas_ST_Mid_New	10.1	10.1	10.1	10.2
Gas_ST_Mid_Old	9.6	9.7	9.8	9.8
Gas_ST_Small_New	10.5	10.5	10.6	10.6
Gas_ST_Small_Old	10.9	10.9	10.9	10.9
Gas_CC_Big	5.6	5.7	5.7	5.7
Gas_CC_Mid_New	5.9	5.9	6.0	6.0
Gas_CC_Mid_Old	8.3	8.3	8.4	8.4
Gas_CC_Small_New	6.9	6.9	6.9	6.9
Gas_CC_Small_Old	7.0	7.0	7.0	7.0
Gas_CT_New	9.0	9.0	9.1	9.1
Gas_CT_Old	12.5	12.5	12.5	12.5
Geothermal	8.0	8.1	8.1	8.1
Nuclear	8.0	8.1	8.1	8.1
Invest_Gas_CC_Mid_New	5.9	5.9	6.0	6.0
Invest_Coal_ST_Mid_New	10.0	10.0	10.1	10.1
Invest_Gas_CT_New	9.0	9.0	9.1	9.1
Invest_Nuclear	8.0	8.1	8.1	8.1

a - The incremental heat rate does not include the no-load heat

Table 18: Thermal generator start-up emissions for NO_x and SO_2. Source: Estimates from Lew et al. (2011) applied to full-load emissions derived from Ventyx.

Generation Vintage	Start-up NO_x (kg/MW-start)	Start-up SO_2 (kg/MW-start)
Coal_ST_Big	5.109	0.779
Coal_ST_Small_New	2.680	2.103
Coal_ST_Small_Old	7.120	6.655
Gas_ST_Big	0.258	0.007
Gas_ST_Mid_New	0.392	0.007
Gas_ST_Mid_Old	0.537	0.007
Gas_ST_Small_New	4.661	0.008
Gas_ST_Small_Old	3.352	0.014
Gas_CC_Big	0.216	0.005
Gas_CC_Mid_New	0.264	0.005
Gas_CC_Mid_Old	3.070	0.007
Gas_CC_Small_New	0.832	0.006
Gas_CC_Small_Old	4.303	0.010
Gas_CT_New	0.990	0.009
Gas_CT_Old	0.466	0.011
Geothermal	0.000	0.000
Nuclear	0.000	0.000
Invest_Gas_CC_Mid_New	0.264	0.005
Invest_Coal_ST_Mid_New	4.491	3.635
Invest_Gas_CT_New	0.990	0.009
Invest_Nuclear	0.000	0.000

from Ventyx, Table 19. NO_x emissions from coal plants are much worse per unit of fuel burned relative to natural gas plants. The average NO_x emissions per unit of fuel burned almost always *increases* as the load factor of CCGT and CT plants decreases, as noted by Denny and O'Malley (2006) and Katzenstein and Apt (2009). The same is not found to be true for operating coal plants in the western U.S.

Table 19: Thermal generator average NO_x emissions rate. Source: Derived from Ventyx

	Average NO_x Emissions Rate (g/MMBtu)			
Generation Vintage	Block 1	Block 2	Block 3	Block 4
Coal_ST_Big	144.0	134.9	171.7	167.4
Coal_ST_Small_New	81.7	67.8	70.5	74.9
Coal_ST_Small_Old	180.3	191.8	199.0	208.7
Gas_ST_Big	3.1	4.0	6.2	8.8
Gas_ST_Mid_New	3.8	7.7	9.8	12.6
Gas_ST_Mid_Old	4.6	4.8	7.7	17.9
Gas_ST_Small_New	134.8	104.4	117.8	144.6
Gas_ST_Small_Old	52.0	60.5	81.1	99.3
Gas_CC_Big	3.2	3.4	3.2	3.2
Gas_CC_Mid_New	7.6	5.8	3.8	3.8
Gas_CC_Mid_Old	61.6	30.2	46.3	35.9
Gas_CC_Small_New	17.3	11.2	10.9	10.9
Gas_CC_Small_Old	54.3	52.5	49.8	49.3
Gas_CT_New	21.9	16.3	13.1	13.6
Gas_CT_Old	36.2	26.5	4.2	4.5
Geothermal	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0
Invest_Gas_CC_Mid_New	7.6	5.8	3.8	3.8
Invest_Coal_ST_Mid_New	115.7	116.7	130.0	143.4
Invest_Gas_CT_New	21.9	16.3	13.1	13.6
Invest_Nuclear	0.0	0.0	0.0	0.0

Similar to NO_x, the assumed average SO_2 rate at the four load factor levels were derived from Ventyx, Table 20. The SO_2 emissions rate for coal plants are three to four orders of magnitude greater than the SO_2 emissions rate for natural gas plants.

The assumed variable O&M costs and the annualized fixed cost for generation vintages are summarized in Table 21. The variable O&M costs are based on the costs reported by Ventyx. The fixed costs are based on the capital cost calculator built by E3 for WECC to use in transmission planning studies. The incumbent generation only has fixed O&M costs, while new investments in generation are required to cover both the investment cost and fixed O&M cost (the sum of which is included in the total fixed cost column).

The assumed fuel costs are based on recent projections of natural gas, coal, and uranium prices for 2030 by EIA, 2011, Table 22. The CO_2 emissions are assumed to be proportional to the fuel use in the thermal plants.

Hydropower is challenging to model accurately due to the many non-economic constraints on river flows downstream of the plant, variable river flows upstream of the plant, and interactions between hydroplants on the same river system. Hydropower modeling is therefore simplified by assuming that the total amount of electrical energy produced by the hydropower vintage in any month must equal the sum of the hydropower generated in a historical year by all hydropower plants within the NERC sub-region, as reported by Ventyx. The hydro generation in the median year between 1990 and 2008 is used to set the monthly hydropower budget, Table 23.

In addition to establishing the monthly generation budget, a minimum and maximum hydropower gen-

Table 20: Thermal generator average SO_2 emissions rate. Source: Derived from Ventyx

	Average SO_2 Emissions Rate (g/MMBtu)			
Generation Vintage	Block 1	Block 2	Block 3	Block 4
Coal_ST_Big	20.6	25.4	22.6	27.4
Coal_ST_Small_New	131.8	92.5	63.9	63.2
Coal_ST_Small_Old	196.5	210.8	221.5	209.5
Gas_ST_Big	0.3	0.3	0.3	0.3
Gas_ST_Mid_New	0.2	0.3	0.3	0.2
Gas_ST_Mid_Old	0.3	0.3	0.3	0.3
Gas_ST_Small_New	0.3	0.3	0.3	0.3
Gas_ST_Small_Old	0.5	0.4	0.4	0.4
Gas_CC_Big	0.3	0.3	0.3	0.3
Gas_CC_Mid_New	0.3	0.3	0.3	0.3
Gas_CC_Mid_Old	0.3	0.3	0.3	0.3
Gas_CC_Small_New	0.3	0.3	0.3	0.3
Gas_CC_Small_Old	0.2	0.4	0.4	0.4
Gas_CT_New	0.7	0.3	0.3	0.3
Gas_CT_Old	0.3	0.3	0.3	0.3
Geothermal	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0
Invest_Gas_CC_Mid_New	0.3	0.3	0.3	0.3
Invest_Coal_ST_Mid_New	121.0	119.2	119.8	124.7
Invest_Gas_CT_New	0.7	0.3	0.3	0.3
Invest_Nuclear	0.0	0.0	0.0	0.0

Table 21: Variable and fixed operating and maintenance cost and annualized fixed cost of thermal generation in the reference scenario

Generation Vintage	Variable O&M Cost[a] ($/MWh)	Fixed O&M Cost[b] ($/kW-yr)	Total Fixed Cost[b] ($/kW-yr)
Coal_ST_Big	1	66	-
Coal_ST_Mid_New	2	66	-
Coal_ST_Mid_Old	1	66	-
Coal_ST_Small_New	2	66	-
Coal_ST_Small_Old	2	66	-
Gas_ST_Big	1	66	-
Gas_ST_Mid_New	2	66	-
Gas_ST_Mid_Old	3	66	-
Gas_ST_Small_New	2	66	-
Gas_ST_Small_Old	2	66	-
Gas_CC_Big	1	9	-
Gas_CC_Mid_New	1	9	-
Gas_CC_Mid_Old	1	9	-
Gas_CC_Small_New	1	9	-
Gas_CC_Small_Old	1	9	-
Gas_CT_New	1	15	-
Gas_CT_Old	1	15	-
Geothermal	5	204	-
Nuclear	4	92	-
Invest_Gas_CC_Mid_New	1	-	203
Invest_Coal_ST_Mid_New	2	-	494
Invest_Gas_CT_New	1	-	194
Invest_Nuclear	4	-	950

a - Source: Derived from Ventyx
b - Source: WECC, 2010

Table 22: Cost of fuel in reference scenario and CO_2 emission rate

Fuel	Cost[a] ($/MMBtu)	CO_2 Emission Rate (kg/MMBtu)
Gas	6.39	53.8
Coal	2.35	93.1
Uranium	1.04	0.0
Geothermal	0.00	0.0

a - Source: EIA, 2011

eration rate are required to model hydropower. The maximum hydropower is assumed to be the sum of the nameplate capacity of all of the hydropower plants in the California NERC sub-region. A minimum hydropower generation rate in each hour was estimated for each month as the average hydropower generation rate that would yield the lowest average monthly generation for that month over the period from 1990 to 2008.

Within these three primary constraints, it was assumed that hydropower plants never shut down or start up. Hydropower is also assumed to be flexible enough to change its generation profile in response to uncertainty and variability in the real-time market. All hydropower is modeled as being co-optimized with the thermal generation (or "hydro-thermal co-optimization") with perfect foresight as opposed to modeling hydro as being dispatched in proportion to the load profile (often called "proportional load-following").

Table 23: Monthly hydropower energy generation budget and minimum generation rate for the 13.3 GW of hydro capacity in the California NERC sub-region. Source: Derived from Ventyx

Month	Monthly Hydro Generation Budget (GWh)	Minimum Hydro Generation(GW)
1	2,248	1.0
2	1,743	1.0
3	2,240	1.8
4	2,701	2.0
5	3,412	2.9
6	3,344	2.7
7	3,178	3.0
8	2,932	2.4
9	2,265	1.9
10	1,761	1.4
11	1,645	1.0
12	2,000	1.1

The 3.5 GW of existing pumped hydro storage (PHS) in the California NERC sub-region was assumed to never retire, to have a reservoir capacity of 10 hours, and to have a round trip efficiency of 81%. New investments in PHS could be made with an annualized fixed cost based on EIA costs estimates for PHS (EIA, 2010). New PHS was also assumed to have 10 hours of reservoir capacity, Table 24.

Table 24: Storage cost and other parameters in the reference case

Characteristic	Parameter
Fixed Cost ($/kW-yr)[a]	706
Reservoir Capacity Ratio (h)	10
Charge Efficiency (%)	90
Discharge Efficiency (%)	90

a - Source: Total storage cost derived from EIA, 2010

Appendix E Decomposition Tables for Sensitivity Scenarios

E.1 No Operational Constraints

Table 25: Decomposition of the marginal economic value of variable generation in a sensitivity scenario where operational constraints are ignored.

Component	Penetration of Wind						
($/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(79) 20	(31) 10	(29) 10	(29) 9	(27) 9	(24) 8	(20) 6
Energy Value	49	48	48	47	47	46	40
DA Forecast Error	0	0	0	0	0	0	0
Ancillary Services	-0.5	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Marginal Economic Value	68	58	57	56	56	53	45

Component	Penetration of PV						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(128) 41	(107) 34	(80) 26	(25) 8	(12) 4	(8) 3	(6) 2
Energy Value	49	49	49	49	47	47	42
DA Forecast Error	0	0	0	0	0	0	0
Ancillary Services	-0.9	-0.8	-0.7	-0.3	-0.1	-0.1	-0.0
Marginal Economic Value	89	83	74	56	51	50	43

Component	Penetration of CSP_0						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(119) 50	(85) 36	(51) 22	(4) 2	(1) 0	(0) 0	(-1) -1
Energy Value	50	50	49	48	47	46	32
DA Forecast Error	0	0	0	0	0	0	0
Ancillary Services	-1.1	-1.0	-0.6	0	0	0	0
Marginal Economic Value	99	86	71	50	47	46	31

Component	Penetration of CSP_6						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(162) 38	(168) 39	(156) 37	(133) 31	(112) 26	(58) 14	(1) 0
Energy Value	49	50	51	53	55	59	59
DA Forecast Error	0	0	0	0	0	0	0
Ancillary Services	1.4	1.3	1.3	2.1	1.6	1.0	0.1
Marginal Economic Value	89	90	90	87	82	74	60

a - Capacity value in parentheses is reported in $/kW-yr terms.

E.2 Carbon Cost

Table 26: Decomposition of the marginal economic value of variable generation in a sensitivity scenario with a \$32/tonne CO_2 carbon cost.

Component	Penetration of Wind						
(\$/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(65) 17	(37) 12	(29) 10	(30) 10	(27) 9	(24) 8	(24) 7
Energy Value	63	62	61	60	60	58	51
DA Forecast Error	-0.3	-4	-4	-2	-2	-4	-7
Ancillary Services	-0.4	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Marginal Economic Value	79	70	66	67	66	62	51

Component	Penetration of PV						
(\$/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(113) 36	(103) 33	(81) 26	(39) 13	(19) 6	(9) 3	(4) 1
Energy Value	68	67	65	61	57	52	36
DA Forecast Error	-0.4	-5	-5	-6	-5	-4	-3
Ancillary Services	-0.9	-0.8	-0.7	-0.5	-0.3	-0.1	-0.0
Marginal Economic Value	102	94	86	67	58	52	34

Component	Penetration of CSP_0						
(\$/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(108) 46	(81) 35	(52) 23	(22) 10	(11) 5	(6) 3	(5) 2
Energy Value	70	69	66	58	52	44	23
DA Forecast Error	-0.6	-5	-5	-6	-5	-4	-5
Ancillary Services	-1.1	-0.8	-0.5	-0.2	-0.1	-0.1	-0.1
Marginal Economic Value	114	97	83	62	52	43	20

Component	Penetration of CSP_6						
(\$/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(148) 36	(150) 36	(146) 35	(135) 32	(102) 24	(75) 19	(38) 10
Energy Value	70	70	70	70	71	67	67
DA Forecast Error	-0.2	-1	-1	-1	-1	-2	-2
Ancillary Services	1.4	1.4	1.3	1.2	1.1	0.7	0.1
Marginal Economic Value	107	106	105	101	95	84	75

a - Capacity value in parentheses is reported in \$/kW-yr terms.

E.3 Cost of Capacity

Table 27: Decomposition of the marginal economic value of variable generation in a sensitivity scenario where the annualized fixed cost of a new CT is reduced from $194 to $139/kW-yr.

Component	Penetration of Wind						
($/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(50) 13	(27) 9	(22) 8	(23) 8	(21) 7	(19) 6	(18) 6
Energy Value	54	53	53	51	52	49	42
DA Forecast Error	-0.1	-3	-3	-2	-2	-3	-6
Ancillary Services	-0.3	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1
Marginal Economic Value	66	59	57	57	57	52	42

Component	Penetration of PV						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(95) 30	(91) 29	(70) 22	(33) 11	(15) 5	(8) 3	(4) 1
Energy Value	59	59	56	52	48	44	27
DA Forecast Error	-0.1	-4	-4	-6	-4	-3	-3
Ancillary Services	-0.7	-0.8	-0.7	-0.4	-0.1	-0.1	-0.0
Marginal Economic Value	88	83	74	57	49	44	26

Component	Penetration of CSP_0						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(91) 39	(67) 29	(44) 19	(16) 7	(8) 4	(5) 2	(1) 1
Energy Value	62	59	55	51	44	34	16
DA Forecast Error	-1.6	-6	-5	-4	-4	-3	-3
Ancillary Services	-0.9	-0.8	-0.4	-0.2	-0.1	-0.2	-0.1
Marginal Economic Value	99	81	70	54	43	33	14

Component	Penetration of CSP_6						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(125) 30	(124) 30	(128) 31	(127) 30	(104) 25	(86) 21	(58) 14
Energy Value	61	59	58	57	60	53	52
DA Forecast Error	-0.1	-1	-1	-1	-1	-2	-3
Ancillary Services	1.3	1.2	1.2	1.1	1.0	0.7	0.1
Marginal Economic Value	93	89	90	88	84	71	63

a - Capacity value in parentheses is reported in $/kW-yr terms.

E.4 No Retirements

Table 28: Decomposition of the marginal economic value of variable generation in case where no retirements occur due to the technical life of thermal generation.

Component	Penetration of Wind						
($/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(20) 5	(12) 4	(10) 4	(8) 3	(7) 2	(8) 2	(7) 2
Energy Value	63	61	58	56	53	48	40
DA Forecast Error	-0.2	-2	-2	-2	-2	-3	-5
Ancillary Services	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Marginal Economic Value	67	63	59	57	53	48	38

Component	Penetration of PV						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(37) 12	(38) 12	(21) 7	(11) 4	(6) 2	(4) 1	(1) 0.4
Energy Value	68	67	65	59	51	44	26
DA Forecast Error	-0.1	-1	-3	-3	-2	-2	-2
Ancillary Services	-0.5	-0.5	-0.4	-0.3	-0.1	-0.0	-0.0
Marginal Economic Value	79	78	68	59	51	43	24

Component	Penetration of CSP_0						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(33) 14	(24) 10	(13) 6	(7) 3	(4) 2	(1) 1	(1) 0.3
Energy Value	69	67	65	56	46	34	17
DA Forecast Error	-0.1	-1	-1	-3	-3	-2	-3
Ancillary Services	-0.6	-0.5	-0.2	-0.1	-0.2	-0.3	-0.1
Marginal Economic Value	83	76	69	57	45	32	15

Component	Penetration of CSP_6						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(54) 13	(48) 12	(47) 11	(41) 10	(16) 4	(14) 3	(0) 0.0
Energy Value	70	69	67	65	62	56	50
DA Forecast Error	0.0	-0.2	-0.4	-0.3	-1	-1	-1
Ancillary Services	1.1	0.9	0.9	0.9	0.6	0.5	0.0
Marginal Economic Value	84	81	79	76	66	59	49

a - Capacity value in parentheses is reported in $/kW-yr terms.

Appendix F Scarcity Pricing and Loss of Load Expectation

F.1 Overview

Investment decisions in the model used in this analysis are based on the requirement that the short-run profit of any new investments must approximately equal the annualized fixed cost of that generation. If the short-run profit were higher then additional generation would enter the market and depress prices. If it were any lower then the new investments would not be made based on the expectation that the short-run profit would not justify the investment cost. The total amount of non-VG generation built in any case is determined by economic decisions captured by this long-run equilibrium constraint.

In contrast, many power system planning studies use a reliability-based approach to determine the amount of generation capacity that needs to be available in order to meet a reliability planning standard. A common approach sets a target loss of load expecation (LOLE) and determines the amount of generation that needs to be built in order to meet this target LOLE. In contrast to the long-run equilbirium approach, the LOLE-based approach is not explicitly based on economic criteria.

Though these two approaches to determining the amount of generation capacity to build in the future are based on fundamentally different criteria, the objective of this section is to illustrate how the two can be related. Based on an illustrative set of simple market rules, we show how a constant short-run profit for a peaker plant implies a constant LOLE. We then derive a relationship between the value of lost load (VOLL), the fixed cost of the peaker plant, and the LOLE based on arguments similar to the discussion of Reliability, Price Spikes, and Investment in Part 2 of Power System Economics (Stoft, 2002).

F.2 Illustration

Consider a simple power market (much more simple than the wholesale power market used in the full model used in this report) where the hourly wholesale price (p^t) can take on only three possible values:

1. $p^t = P_s = VOLL \gg MC$: The wholesale price equals the value of lost load (VOLL) which is much greater than the marginal production cost of the peaker plant (MC)
   - Define the probability of p^t being P_s as ϕ_s^t
2. $p^t = MC$: The wholesale price equals the marginal production cost of the peaker plant
   - Define the probability of p^t being MC as ϕ_m^t
3. $p^t < MC$: The wholesale price is less than the marginal production cost of the peaker plant.
   - Define the probability of p^t being less than MC as ϕ_0^t

Since only three price levels can occur, the sum of the probabilities of each price level is one: $\phi_s^t + \phi_m^t + \phi_0^t = 1$.

The dispatch of the peaker plant is also assumed to be very simple and depend on the wholesale prices:

1. $q^t = K$ when $p^t = P_s$: The peaker plant generates at its full nameplate capacity (K) when the wholesale price is equal to the VOLL
2. $q^t \geq 0$ when $p^t = MC$: The peaker plant is dispatched to any level when the peaker plant is the marginal unit and the wholesale price equals the marginal production cost of the peaker plant.
3. $q^t = 0$ when $p^t < MC$: The peaker plant is off when the price is below the marginal production cost of the peaker plant.

The short-run profit (per unit of capacity) in any hour is based on the revenues earned from selling its output into the wholesale power market and the production costs.

$$SR_\pi^t = (p^t - MC)q^t/K$$

As a result of these three potential prices and the dispatch based on the prices, there are only two resulting values that the hourly short-run profit can be for the peaker plant in each hour.

1. $SR_\pi^t = (P_s - MC) \approx P_s$: When the wholesale price is equal to the VOLL or P_s, the peaker plant is dispatched to its full nameplate capacity. The hourly short-run profit will be the difference between the VOLL and the marginal production cost of the peaker. Since the VOLL is much greater than the marginal cost of the peaker, the short run profit is approximately equal to the VOLL. This hourly short-run profit occurs with a probability of ϕ_s^t.

2. $SR_\pi^t = 0$: When the wholesale price equals the marginal production cost, the short-run profit is zero, no matter how much the peaker plant generates. When the wholesale price is below the marginal production cost of the peaker, the short-run profit is zero because the peaker plant will be offline. Together this hourly short-run profit occurs with a probability of $\phi_m^t + \phi_0^t = (1 - \phi_s^t)$.

Based on the fact that there are only two possible values for the hourly short-run profit of the peaker plant, the expected value of the short-run profit in each hour is:

$$\mathbb{E}(SR_\pi^t) = \phi_s^t P_s + (1 - \phi_s^t)0 = \phi_s^t P_s$$

Over a long period, T, the total expected short-run profit of the peaker plant (SR_π) is:

$$\mathbb{E}\left(SR_\pi = \sum_{t \in T} SR_\pi^t\right) = \sum_{t \in T} \mathbb{E}\left(SR_\pi^t\right) = \sum_{t \in T} \phi_s^t P_s = P_s \sum_{t \in T} \phi_s^t$$

The long-run equilibrium constraint implies that in equilibrium, the expected value of the short-run profit of any new peaker plant that is built will equal the fixed investment cost of the peaker plant (FC_p). Therefore the long-run equilibrium constraint implies:

$$\mathbb{E}\left(SR_\pi\right) = P_s \sum_{t \in T} \phi_s^t = FC_p$$

As long as the system is in long-run equilibrium and some new peaker plants are built, the sum of the hourly probabilities of price spikes across all hours will be kept at a constant level:

$$\frac{FC_p}{P_s} = \sum_{t \in T} \phi_s^t = \text{constant}$$

Even if variable generation were to be added to this simple market or if the shape of the load were to change, as long as the market moves to a new long-run equilibrium and new peaker plants are built in that long-run equilibrium the sum of the hourly probabilities of price spikes across all hours will remain equal to the ratio of the fixed cost of the peaker plant and the value of lost load, FC_p/P_s.

If the only time that the wholesale power price rises to the value of lost load is when the demand (L^t) exceeds the total amount of all generation (G^t) in that hour (including the contribution from the peaker plant and any variable generation), then the probability of the price being equal to the value of lost load is the same as the probability of the demand being than generation:

$$\phi_s^t = \phi(L^t > G^t)$$

The loss of load expectation over a long period T is defined as:

$$LOLE = \sum_{t \in T} \phi(L^t > G^t)$$

Therefore, the loss of load expectation is equivalent to the sum of the hourly probabilities of price spikes across all hours. In long-run equilibrium when new peaker plants are built, the LOLE is constant and is based on the ratio of the fixed cost of the peaker plant and the value of lost load, FC_p/P_s:

$$LOLE = \sum_{t \in T} \phi(L^t > G^t) = \sum_{t \in T} \phi_s^t = \frac{FC_p}{P_s} = \text{constant}$$

An effective load carrying capability (ELCC) analysis of the capacity value of variable generation seeks to determine the change in the amount of load that can be met with and without variable generation while holding the LOLE constant (e.g., Milligan, 2000). This relationship between LOLE and the long-run equilibrium constraint illustrates that the ELCC of variable generation found through an LOLE analysis is based on similar drivers to the implied capacity credit found with a system that is in long-run equilibrium with and without variable generation.

F.3 Implications

Since the LOLE is fixed based on the ratio of the fixed cost of a peaker and the value of lost load, FC_p/P_s, the overall reliability of the system modeled in this simple illustration is tied to the estimate of the value of lost load. Assume that the peaker plant has a fixed investment cost of \$200,000/MW-yr. Then if the value of lost load is assumed to be \$10,000/MWh the loss of load expectation will be 20 hours per year (or load shedding will occur during approximately 0.22% of the hours in a year.

If the desire were to have a lower loss of load expectation of 1-day in 10 years (or 2.4 hours per year) then the VOLL would need to be closer to \$83,000/MWh.

The implication for estimating the marginal economic value of variable generation is that the choice of the VOLL determines the number of hours per year when the price spikes to high levels. A higher choice of the VOLL would lead to fewer hours with high prices and therefore relatively more weight on the amount of generation during those high price hours.