Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making

Authors:

Joachim Seel*, Andrew Mills, Ryan Wiser [1]

Sidart Deb, Aarthi Asokkumar, Mohammad Hassanzadeh, Amirsaman Aarabali [2]

[1] Lawrence Berkeley National Laboratory

[2] LCG Consulting

Energy Analysis and Environmental Impacts Division Lawrence Berkeley National Laboratory

Electricity Markets and Policy Group

May 2018

This technical report, a briefing, and underlying data sets are available at:

https://emp.lbl.gov/publications/impacts-high-variable-renewable

*Corresponding author: jseel@lbl.gov

Disclaimer

Copyright Notice

Acknowledgements

Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
AS	Ancillary Services
CCGT	Combined Cycle Gas Turbine
CT	Combustion Turbine
DR	Demand Response
EE	Energy Efficiency
EM&V	Evaluation, Measurement & Verification
IRP	Integrated Resource Plan
ISO	Independent System Operator
ORDC	Operating Reserve Demand Curve
RPS	Renewables Portfolio Standard
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
TDV	Time-Dependent Valuation
VRE	Variable Renewable Energy

Executive Summary

Increasing penetrations of variable renewable energy (VRE) can affect wholesale electricity price patterns and make them meaningfully different from past, traditional price patterns. Many long-lasting decisions for supply- and demand-side electricity infrastructure and programs are based on historical observations or assume a business-as-usual future with low shares of VRE. Our motivating question is **whether certain electric-sector decisions that are made based on assumptions reflecting low VRE levels will still achieve their intended objective in a high VRE future.** We qualitatively describe how various decisions may change with higher shares of VRE and outline an analytical framework for quantitatively evaluating the impacts of VRE on long-lasting decisions.

We then present results from detailed electricity market simulations with capacity expansion and unit commitment models for multiple regions of the U.S. for low and high VRE futures. We find a general decrease in average annual hourly wholesale energy prices with more VRE penetration, increased price volatility and frequency of very low-priced hours, and changing diurnal price patterns. Ancillary service prices rise substantially and peak net-load hours with high capacity value are shifted increasingly into the evening, particularly for high solar futures.

Wholesale Price Effects of 40-50% Wind & Solar
(Wind: 30% wind & 10+% solar | Balanced: 20% wind & 20% solar | Solar: 30% solar & 10+% wind)

Impacts in 2030 relative to baseline with 2016 wind & solar shares	Southwest Power Pool 2016: 18% wind & 0% solar			NYISO (New York) 2016: 3% wind & 1% solar			CAISO (California) 2016: 7% wind & 14% solar			ERCOT (Texas) 2016: 16% wind & 1% solar		
	Wind	Balanced	Solar	Wind	Balanced	Solar	Wind	Balanced	Solar	Wind	Balanced	Solar
Lower Average Prices [$/MWh]	-19%	-21%	-27%	-37%	-38%	-39%	-25%	-23%	-27%	-25%	-17%	-15%
More Hours <$5/MWh In baseline: 0% of all hours	6%	8%	13%	2%	7%	11%	6%	7%	11%	6%	11%	19%
Changes in Diurnal Price Profile red baseline shows 2016 wind & solar shares												
More Price Variability	1.8x	2.1x	2.5x	2.1x	2.3x	2.5x	3.0x	2.9x	3.4x	1x	4.7x	6.6x
Higher AS Prices Regulation Down	5x	6x	9x	2x	2x	3x	3x	3x	3x	2x	3x	4x
Change in Timing of Top Net-Load Hours	Shift from 4pm to 7pm			Shift from 3pm to 5-7pm			No further shift 7pm			Shift from 3pm to 6-8pm		

While in this paper we only highlight <u>qualitatively</u> the possible impact of these altered price patterns on other demand- and supply-side electric sector decisions, the core set of electricity market prices derived here provides a foundation for later planned <u>quantitative</u> evaluations of these decisions in low and high VRE futures.

Note: The raw model output of hourly energy and ancillary service prices, annual capacity prices, and information about the selected generator portfolios is made publicly available on our publication website. A slide deck briefing and a webinar recording are posted there as well.

https://emp.lbl.gov/publications/impacts-high-variable-renewable

1. Introduction

Many long-lasting decisions for supply- and demand-side electricity infrastructure and programs are based on historical observations or assuming a business-as-usual future with low shares of variable renewable energy (VRE).[1] As the share of VRE increases, however, fundamental characteristics of the power system will change. These include the timing of when electricity is cheap or expensive, the locational differences in the cost of electricity, and the degree of regularity or predictability in those costs. Many of these changes can be observed through changes in the patterns of wholesale prices, and initial impacts are already being observed internationally and in some regions of the U.S. where high instantaneous penetrations of wind and solar are already a regular occurrence.

These price shifts can have indirect effects on other demand- and supply-side resources in the electricity sector, particularly if their demand or supply characteristics are inflexible and long-lasting (i.e., cannot change easily over the short-term in response to changing wholesale price patterns). Our research is motivated by the question of **whether electric-sector decisions that are made based on assumptions reflecting low VRE levels will still achieve their intended objective** (whether related to affordability, reliability, or environmental outcome) **in a high VRE future.** We aim to signal to stakeholders that the potential shift to high VRE futures can affect wholesale prices in ways that should be considered in the decision-making framework they use to evaluate long-lasting electricity infrastructure and programs. We plan to offer tangible examples for how changing wholesale price patterns can be considered and to highlight types of decisions where future levels of VRE might be a particularly important factor. As a foundational step, we first develop a common set of wholesale electricity prices from detailed electric market simulations with low and high VRE futures.

In this paper, we first provide a brief theoretical explanation for why growth in VRE can induce changes in wholesale prices in Section 2. In Section 3 we qualitatively analyze a variety of long-lasting electric-sector decisions to assess the risk that decisions based on past assumptions reflecting low VRE penetrations will not achieve their intended objective in a high VRE future. After introducing a broader set of such decisions in question, we showcase three examples in more detail: the optimal selection of energy efficiency portfolios, regulatory implications for the electrification of gas end-uses (i.e., water heaters), and incentives for nuclear flexibility. In Section 4 we develop an analytical framework for quantitatively assessing these decisions based on simulations of future power markets with varying shares of VRE. We describe our VRE penetration scenarios, a capacity expansion model that we use to select different portfolios of generators for the year 2030, a unit commitment model that we use to simulate hourly price series and marginal emission rates, and finally four regional case studies focused on large and diverse organized wholesale market regions in the U.S.: CAISO, ERCOT, SPP and NYISO. Section 5 presents key findings of our modeling efforts, namely a modest net-retirement of firm capacity driven by VRE additions, a substantial decrease in electricity generation by coal and natural gas combined cycle plants, and a reduction in the marginal carbon emissions rate relative to the low VRE future. In scenarios with as much as 44% VRE (post-curtailment), average annual hourly wholesale energy prices

---

[1] See our discussion in Section 3.

decrease by $5-$16/MWh, very low-priced hours below $5/MWh become much more ubiquitous (approaching 20% of all hours of the year in ERCOT), diurnal price profiles change substantially depending on the high VRE scenario, and overall energy price volatility increases. We also find a general increase in regulation and spinning reserve prices by a factor of two to eight. Peak net-load hours associated with a high capacity value tend to shift later into the evening and accrue over a shorter range of hours while occurring over a larger set of days. Section 6 concludes with a discussion and an outlook on future research efforts.

This paper <u>qualitatively</u> highlights some of the possible impacts of these altered price patterns on other demand- and supply-side electric sector decisions, but also serves as the foundation for planned <u>quantitative</u> evaluations. Specifically, later phases of our research will use the simulated wholesale market prices to explore on a quantitative basis how various demand- and supply-side decisions might be affected by changes in the future electricity supply mix.

2. Background

Increasing penetrations of VRE can affect wholesale electricity markets. Although the degree and form of impact varies significantly based on local electricity system configurations, high VRE levels can change the timing of when electricity is cheap or expensive, the locational differences in the marginal cost of electricity, and the degree of regularity or predictability in those costs.

2.1 Evidence of VRE-induced Price Changes

Many of these developments can be observed through changes in the patterns of wholesale prices – although it would be wrong to attribute all price changes exclusively to VRE growth, especially in an environment with dynamic natural gas pricing or stagnant load growth. A broad body of literature has discussed these empirical effects both internationally[2] and in the United States[3].

For example, analyses of wholesale prices in Australia (Gilmore, Rose, Vanderwaal, & Riesz, 2015) show that the deployment of photovoltaic capacity can lead to price changes: historical capacity additions by 2013 had already eroded a mid-day peak in prices in comparison to 2009 and caused the diurnal price profile to flatten significantly. Forward-looking modeling projections for the year 2030 exhibit a further reversal in price peaks to non-solar hours in the early morning and late evening. Keay (2016) summarizes recent European developments and demonstrates a substantial flattening in German diurnal price profiles between 2000 and 2012 that coincided with strong deployment in solar capacity.

---

[2] See for example Clò, Cataldi, & Zoppoli, 2015; Cludius, Hermann, Matthes, & Graichen, 2014; Cutler, Boerema, MacGill, & Outhred, 2011; Ederer, 2015; Haas, Lettner, Auer, & Duic, 2013; Kyritsis, Andersson, & Serletis, 2017; Perez-Arriaga & Batlle, 2012; Sáenz de Miera, del Río González, & Vizcaíno, 2008; Sensfuß, Ragwitz, & Genoese, 2008a; Welisch, Ortner, & Resch, 2016; Würzburg, Labandeira, & Linares, 2013.

[3] See for example Bajwa & Cavicchi, 2017; DOE, 2017; Gil & Lin, 2013; Haratyk, 2017; Hogan & Pope, 2017; Jenkins, 2017; Maggio, 2012; Makovich & Richards, 2017; Wiser et al., 2016; Woo et al., 2013, 2014; Woo, Horowitz, Moore, & Pacheco, 2011; Woo, Horowitz, et al., 2016; Woo, Moore, et al., 2016.

Similar developments can be found increasingly in the United States as well. Wiser et al (2017) comprehensively review wholesale electricity price data of U.S. ISOs and find evidence of changed temporal and geographic price patterns in areas with high VRE penetrations. Growth in PV in the California market drove down net-load levels during the mid-day in 2017 relative to 2012 resulting in an associated change in price patterns (U.S. Energy Information Administration (EIA), 2017). In contrast to more even prices over the course of the day in the first half of 2015, the more recent price profile resembled a "duck" in the first half of 2017. In particular, prices have a local maximum around 7am at slightly under $40/MWh followed by a mid-day price slump of about $15/MWh and an evening price peak of nearly $60/MWh at 8pm. Another example of VRE-induced price changes are low power prices at night in wind-rich areas in Texas that have caused some electricity retailers to offer "free" electricity at night (Krauss & Cardwell, 2015).

2.2 Theory

The basic effects of VRE on short-term price formation in wholesale markets are well understood and have been discussed widely in the literature (Brancucci Martinez-Anido, Brinkman, & Hodge, 2016; Deetjen, Garrison, Rhodes, & Webber, 2016; EnerNex Corporation, 2010; Fagan et al., 2012; GE Energy, 2010; LCG Consulting, 2016; Levin & Botterud, 2015; Mills & Wiser, 2014; NESCOE, 2017; NYISO, 2010; Sensfuß, Ragwitz, & Genoese, 2008). While the specifics vary with the particularities of individual wholesale markets and their different load patterns, VRE resource quality and forecast uncertainty, and the existing generation portfolio, this introduction provides a general overview of the price effect of variable renewable energy, drawing in particular on a description by Felder (2011).
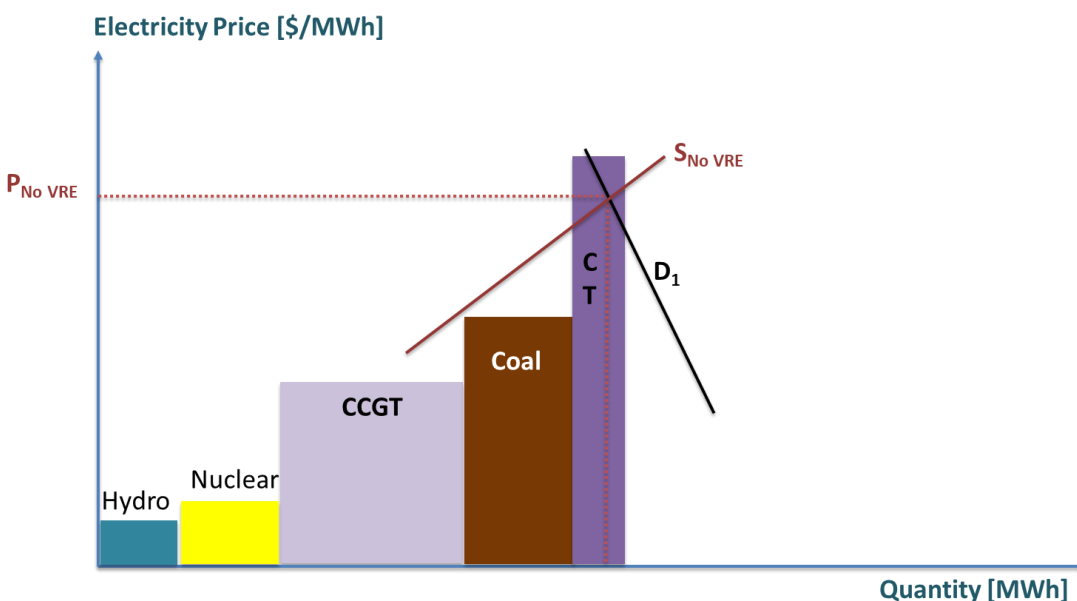
Figure 1 Price Formation without VRE Generators

Figure 1 depicts a simplified standard generator portfolio without VRE generators, ordered along the x-axis by increasing marginal production costs, where the width of each bar represents the available capacity of the generators. At any given point in time, the price of electricity is based on the marginal

production cost of the last generator needed to meet demand (the marginal generator). Similarly, the marginal emissions rate depends on the emissions rate of the marginal generator. Even though hydro resource availability may change over the course of the year, the overall shape of the supply curve ($S_{No\ VRE}$) is fixed over the short-term absent any forced generator outages. Hence, variations in the electricity price over time are primarily due to varying demand levels (e.g., D_1) that change over the course of the day, week or season intersecting at different points with the relatively stable supply curve.
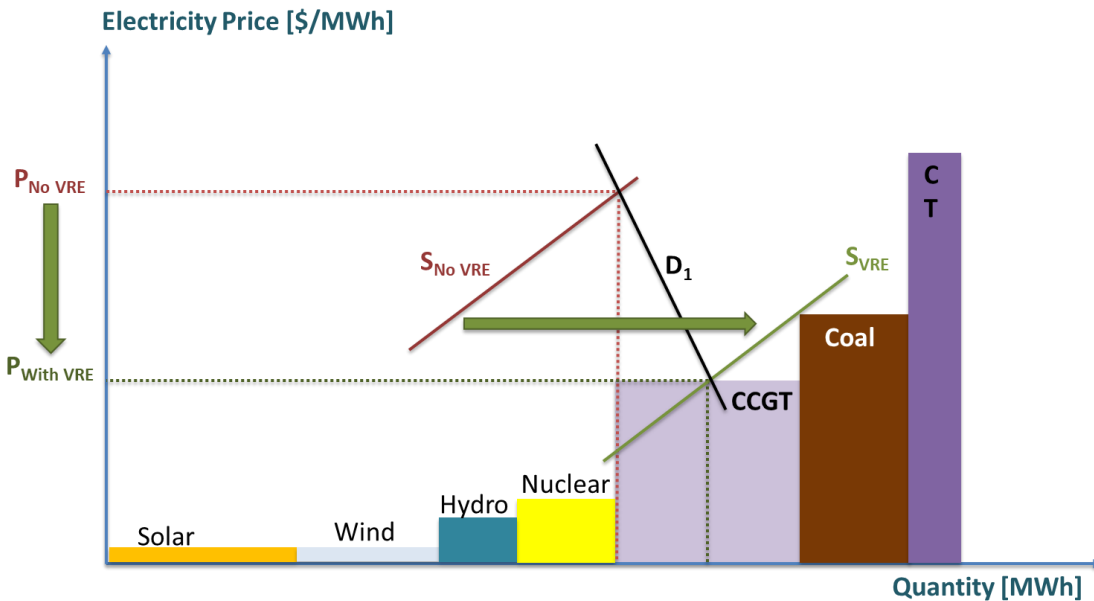
Figure 2 Price Formation with VRE Generators

Figure 2 shows the addition of solar and wind generation to the electricity supply mix. As marginal generation costs are near zero (in some instances even below zero due to the value of renewable electricity credits or other production incentives) they are added at the left side of the supply stack and shift the remaining supply curve to the right from $S_{No\ VRE}$ to S_{VRE}. As a consequence, the marginal generator in the example shifts from a combustion turbine to a combined cycle gas turbine and the new intersection of the demand and supply curve results in a price decline for that time interval (e.g., hour) from $P_{No\ VRE}$ to $P_{With\ VRE}$. Given that the magnitude of the shift in the supply curve depends on the amount of solar and wind generation in that hour, price levels can fluctuate now not just with changing demand levels but also with variable levels of renewable energy generation. To be sure, the change in clearing prices and associated revenue will differ over the medium- to long-term with adjustments in the composition of the supply curve, as some generators retire and other generators may enter the market. As a result, the slope of the supply curve may also shift as the market approaches a new long-run equilibrium.
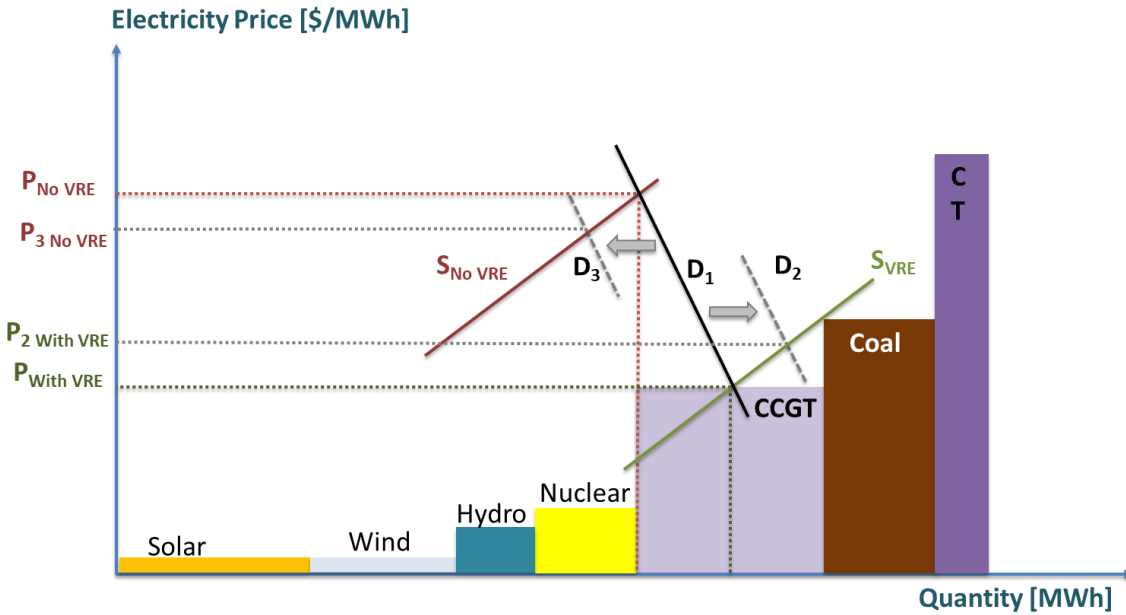
Figure 3 Potential for Demand Changes that Shift Load into Periods with VRE Generation

Figure 3 highlights the opportunity to adjust some demand in response to the new changed price patterns. In particular, some loads may be able to increase their demand at times of low prices (induced by high VRE levels) from D_1 to D_2, thus mitigating an overall price decline to P_2. Other loads may similarly be able to reduce their electricity demand at times of low VRE generation and high prices from D_1 to D_3, alleviating price spikes from $P_{No\ VRE}$ to $P_{3\ No\ VRE}$. Several of the demand-side decisions examined in Table 1 in Section 3 of this paper would aim at facilitating this shift in the future. While we presented here a simple illustration of how prices are affected by VRE, Sections 4 and 5 describe the detailed power system models that were used to quantitatively show the impacts of high VRE futures in particular regions of the U.S.

Wiser et al (2017) identified further impacts of VRE on wholesale power prices, such as changes in temporal (e.g., diurnal or seasonal) and geographic (e.g., between price hubs and individual nodes) patterns of prices, increased price volatility and unpredictability, and a greater frequency of low or negative prices. Unit commitment changes often include lower capacity factors of conventional base- and mid-merit thermal units along with an increase in cycling costs due to increased net-load variability and uncertainty (Bistline, 2017; Bloom et al., 2016; GE Energy, 2014; Lew et al., 2013). Higher VRE penetration is also expected to expand the demand for more regulation reserves[4], although VRE itself has traditionally not supplied such ancillary services due to technical, economic or administrative constraints. As a result, ancillary service prices are thought to rise with higher VRE penetration, in particular for regulation services – non-spin (and to some extent spinning) reserves seem to be less affected (Deetjen et al., 2016; Hummon et al., 2013; LCG Consulting, 2016; Levin & Botterud, 2015). Finally, because of the aforementioned decrease in average wholesale energy prices, studies find an increase in the relative revenue from ancillary service and capacity markets, and scarcity price events.

---

[4] See the appendix for the regulation assumptions in this study.

3. Impacts to Long-Lasting Electric-Sector Decisions

As detailed in the previous sections, higher penetrations of VRE have the potential to change wholesale electricity prices in the United States so that they are meaningfully different from historical price patterns. These price shifts of energy, ancillary service and capacity products can have indirect effects on other demand- and supply-side resources in the electricity sector, particularly if their demand or supply characteristics are inflexible and long-lasting (i.e., cannot change easily over the short-term in response to changing wholesale price patterns).

This motivates the question of **whether certain electric-sector decisions that are made based on assumptions reflecting low VRE levels will still achieve their intended objective in a high VRE future.** Table 1 identifies a non-exhaustive set of long-lasting demand- and supply-side decisions that may be sensitive to deployment of large shares of VRE.[5] To illustrate this point, we focus on three of the decisions: the selection of optimal energy efficiency portfolios, the influence of regulations on the electrification of gas end-uses, and considerations of nuclear flexibility incentives. For each example we highlight the type of long-lasting decisions confronting a potential regulator or program administrator, discuss analytical tools that are used to make the decision, and identify how and why decisions might change in futures with high VRE. In many examples the changes in decisions associated with high VRE do not require new technologies, instead the relative attractiveness of existing technologies or options changes. In other examples, we highlight how R&D priorities for developing new technologies might change with high VRE futures. Overall, the purpose of this discussion is to demonstrate that a diverse set of decision makers may need to consider the potential shift to high VRE futures in the decision-making framework they use to evaluate long-lasting electricity infrastructure and programs.

	Decision	Relevant Change with High VRE	Potential Change in Decision
Demand-Side Decisions	What combinations of energy efficiency measures are most cost effective: commercial office AC vs. residential lighting?	- High solar lowers prices on hot summer days, but not at night	Shift emphasis from commercial office AC to residential and street lighting
	Which is better: electric or gas water heaters?	- VRE lowers carbon content of electricity - VRE, especially wind, needs more flexible loads	Electric hot water heaters (with DR capabilities) may be better than gas in high wind generation areas
	What kind of demand response services are most cost-effective?	- Less predictability of when high price periods will occur - Need load to increase during over-generation	Shorten notification periods for DR, identify ways for DR to increase load, differentiate DR services

---

[5] Many of these along with additional examples are discussed by Lazar (2016) in the context of solutions to mitigate challenges with high shares of solar.

Demand-Side Decisions	Where should electric vehicle charging infrastructure be built: commercial or residential locations? What kind of charging technology should be deployed?	- VRE requires more flexibility - Solar lower prices in afternoons	Increased value in vehicle-2-grid and, with high solar, day-time charging infrastructure (i.e., at commercial locations rather than residential)
	How efficient are different retail rate designs?	- Wholesale prices will shift with VRE, with indirect effects for retail rates	Under time-varying rates, pricing periods and levels will shift with high VRE. More dispersed peak net-load days require adjustments to critical peak pricing programs.
	Should an advanced commodity production process be designed to run continuously or in batches?	- High VRE increases periods with low or negative prices	Promote research on processes that can use cheap electricity over short periods (e.g., air separation, oil refinery, pulp and paper, irrigation pumping, recycle smelting)
Supply-Side Decisions	How large of an incentive is needed (if at all) to ensure revenue sufficiency for existing nuclear plants? Is it cost-effective to increase their flexibility?	- VRE lowers off-peak prices and requires more flexibility	Inflexible generation, including nuclear plants, have less opportunity to profit in high VRE regions
	Is a highly flexible reciprocating engine more cost-effective than a CCGT?	- VRE requires more flexibility, lowers wholesale energy prices but increases ancillary service prices	Increased role for reciprocating engines in high VRE future
	Is it cost-effective to build new energy storage?	- VRE increases the volatility of prices and solar narrows peaks	Increased role for storage, with duration depending on dominant VRE type
	What are the impacts of alternative water flow regimes in hydropower relicensing?	- VRE increases volatility of energy prices and changes timing and relative importance of providing ancillary services	Alternative flow regimes may have greater impact on projected revenues, on fish and wildlife, on recreation, on irrigation, and on navigation.
	Where should wind and solar assets be sited and how should project design evolve?	- VRE will decrease wholesale energy prices at times of generation if output is highly correlated	Shift location to areas that are better aligned with high-priced hours, encourage south-western orientation of PV modules, taller wind turbine towers with lower specific power ratings, co-location with energy storage

Table 1: Illustrative Examples of Electricity-Sector Decisions that May Change with Increasing VRE Penetration

3.1 Example: Energy Efficiency Portfolio Selection

Although energy efficiency (EE) programs can differ significantly in their design and goals across states and utilities, a central task for EE program administrators is the **selection of suitable combinations of EE measures that decrease overall energy consumption, curb demand growth and reduce overall electric system needs in the most cost-effective manner**. EE measures are diverse, and the overall mix and relative weight of different efficiency measures is important.

Formalized cost-effectiveness tests for EE measures have existed for nearly 35 years.[6] The vast majority of states rely on the "*Total Resource Cost Test* (**TRC Test**)" when they evaluate the costs and benefits of EE measures (ACEEE, 2016).[7] For the TRC, most states limit the inputs of the benefits-side of the equation to avoided utility energy and capacity costs and program costs, though the test can also include gas and water savings, and monetized non-energy benefits to participants (Lazar & Colburn, 2013).[8] More specifically, value components that are often considered in the TRC include production capacity and energy costs, environmental compliance costs, transmission & distribution capacity costs, avoided line losses, and reductions in reserve requirements.[9] The "*Societal Cost Test* (**SCT**)" is less commonly used but is more comprehensive and may include non-monetized benefits and impacts such as air quality impacts, employment impacts and broader economic development impulses.

A recent interest (aided by AMI data that facilitate EM&V processes) is an increased shift from average valuations to time-dependent valuations (TDV) for EE measures (Boomhower & Davis, 2016; Mims, Eckman, & Goldman, 2017; Mims, Eckman, & Schwartz, 2018; Stern, 2013). In contrast to earlier analyses that utilize annual or seasonal average energy costs (differentiated by broad peak- vs. off-peak categories), new valuation analyses use higher resolution time series with hourly energy values and time-dependent capacity values of different EE measures.

A second differentiating feature in cost-effectiveness evaluations is the temporal perspective, where either historical time series or projections about future time series can be used. Traditionally, program designers relied on historical records to create "coincidence factors" for state technical reference manuals. However, a recent national practice manual suggests forward-looking evaluations (Woolf, Neme, Kushler, Schiller, & Eckman, 2017) and several utilities include EE measures in their load demand curve modeling during their periodic Integrated Resource Plans (IRPs) and optimize efficiency portfolios.[10]

---

[6] See e.g., California's 1983 Manual "Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs."

[7] Less commonly used cost-effectiveness tests are the "*Participant Cost Test* (PCT)", the *"Rate Impact Measure Tests* (RIM test)" or the "*Program Administrator Cost Test* (PAC test)."

[8] Taking a more expansive view can be important as non-energy benefits can be as large or greater than energy benefits alone (Myers & Skumatz, 2006; Neme & Kushler, 2010).

[9] These direct benefits are usually evaluated over the measure's useful lifetime on a net-present-value or levelized costs / benefit basis. Other indirect benefits might include less exposure to risk (e.g., fuel price volatility), or secondary obligations such as renewable energy shares of retail electricity. Of course, proper evaluations must also consider any indirect costs, such as any lost consumer utility due to reduced measure functionality.

[10] See for example the 7th Power Plan by the Northwest Power & Conservation Council (NWPCC) that leverages their ProCost model to evaluate more than 50 energy efficiency measures with hourly time resolution or Pacificorp's 2015 IRP that evaluates 27 measures on an hourly basis.

IRP modeling can in principle assess EE portfolio performance across different future scenarios, but this is not yet standard for most utilities and the evaluated scenarios rarely include high renewable penetration cases. Our research provides a framework to evaluate the extent to which a low VRE future scenario will lead to a different EE portfolio selection when compared to a high VRE scenario.

With changing energy supply options and changing peak and off-peak periods, the relative share in the efficiency portfolios of near-constant load reduction measures (such as more efficient refrigerators), traditional off-peak measures (such as street lighting or residential lighting) or traditional on-peak measures (such as high efficiency air conditioning units) may need to change in order to continue optimal resource selection and prevent misaligned EE investments. For example, high shares of solar can depress prices during the day and shift peak times to the early evening. This indicates that traditional on-peak measures, like commercial office building air conditioning programs, may become less valuable while traditional off-peak measures, like street and residential lighting, may increase in value.

3.2   Example: Electrification of Gas End-Uses

The electrification of combustion-based end-uses has attracted increasing interest due the promises of air quality and carbon intensity improvements (Dennis, 2015; Dennis, Colburn, & Lazar, 2016), greater flexibility for managing electric loads, and integrating larger shares of variable renewable energy. Examples include space or water heating with advanced electric heat-pumps or electric resistive heating, electric stoves or clothes dryers, as well as the electrification of industrial processes. In several use-cases the primary barriers to the adoption of electric technologies are economic and not technological, and the prospects for electrification are often affected by a large variety of policies, programs and regulations (Deason, Wei, Leventis, Smith, & Schwartz, 2018).

One example of regulations influencing the adoption of electric water heaters is Title 24 of the California Building Code, which requires an evaluation of the overall energy consumption and associated costs for new or substantially retrofitted buildings. Historically, gas-fired water heaters have performed better in these evaluations in comparison to electric water heaters. Given the longevity of water heating investment decisions, policy makers need robust information about **how the value proposition of electric vs. gas-fired heaters may change over the lifetime of the appliance.** In California, the assessment of the energetic performance of buildings is done via a TDV of both the gas and electricity consumption over a 30-year time period. The California Energy Commission (CEC) has developed a time-differentiated electricity and gas price forecast that is used to derive the net-present-value of the building's energy consumption.[11] The CEC uses currently only a singular scenario for both electricity and gas forecasts. Current components of the CEC's time-dependent-valuation for electricity consumption include values for energy, capacity, ancillary services, CO_2 emissions, transmission and distribution utilization, system losses, and Renewables Portfolio Standard (RPS) obligations. As the carbon intensity of the Californian electricity mix decreases with increasing shares of renewable electricity, the CO_2 emissions associated

---

[11] The TDV methodology and associated price forecasts are re-evaluated every 3 years and recent price forecasts have already started to show electricity price reductions during the middle of the day that are associated with an increase in solar electricity generation (Ming et al., 2016).

with an electric water heater are likely to decrease and outperform traditional natural gas water heaters, especially when advanced heat-pumps are used.

Additionally, the load and thermal mass of electric water heaters might be leveraged strategically to enable new value streams for both the private customer as well as the broader electricity system. These "products" could include shifting demand to periods of lower electricity prices, avoiding load during hours of peak demand, or offering ancillary services. While there has not been much demand for these services historically, the degree of usefulness and cost-effectiveness will depend on the future mix of electricity generation assets. Specifically, high shares of wind and/or solar increase the value of the load flexibility that electric water heating can provide.

3.3 Example: Nuclear Flexibility Incentives

According to EIA's Annual Energy Outlook 2018 main scenario (U.S. Energy Information Administration, 2018), nuclear generation remains rather stable, declining only from 99GW in 2017 to 79GW in 2050. However, greater amounts of VRE may accelerate nuclear retirements at the regional level, as shown by recent experience at Diablo Canyon in California (Wiser et al., 2017) and Fort Calhoun in Nebraska (Haratyk, 2017; Morris, 2016), due to average wholesale price erosion and system flexibility demands. A system with large amounts of both VRE and nuclear power may require either more flexible nuclear plant operations, contractual arrangements that reduce financial losses for plant owners, or more intense use of other renewable energy integration options. Policymakers could choose to support the role of nuclear in the national energy mix by **increasing R&D on flexible nuclear plant design and operations**, addressing **technical regulations on nuclear plant operations**, or considering the **size of the required incentive** (if at all) to either keep nuclear plants operating in a low or high VRE future despite output curtailment, or to increase operational flexibility via plant retrofits.

While incentive costs, R&D program administration costs, or nuclear plant retrofit costs may not be directly affected by the degree of renewable energy penetration, a high VRE future may shift the focus and change the required degree of flexibility supply by nuclear power plants, thus necessitating different technical innovations in power plant design and operation. As such, our research will investigate the revenue impacts of a low and high VRE future on both a "traditionally operating" and "flexible" nuclear plant. Revenue generating value streams will feature traditional energy and capacity values, but may also include ancillary services (to the extent that more flexible generators will be able to play in that field). This information will help understand the economic implications for inflexible nuclear plants and the economic and technical implications of nuclear dispatch, ramping, and seasonal operations for existing and next-generation nuclear plants.

4. Analytical Framework for Quantitative Assessment

Beyond the qualitative assessment in the previous section, we expect many decision makers to value an economically rigorous analytical framework for analyzing how optimal decisions may change in a high VRE future. At a high level, decisions often come down to a comparison of the marginal benefits of implementing some project or program to its marginal costs. Marginal benefits can be quantitatively

estimated by using wholesale market prices and marginal emissions rates. For this purpose, we first develop wholesale price series for energy, capacity and ancillary service products and marginal emission rates for the year 2030 in four U.S. regions under different VRE penetration scenarios. We present our findings of changes in wholesale electricity prices in Section 5.

To guide our research, we assembled a technical review committee of subject matter experts (including electricity market modeling personnel of the ISOs) that has provided both general critical feedback and validation of specific scenario design questions. Finally, we partnered with the electricity consulting company LCG Consulting to develop our VRE scenarios and to use their electricity market modeling tools, Gen-X and UPLAN, to derive future generator portfolios and hourly price and emissions series. Figure 4 provides an overview of our research design that will be elaborated on in the remainder of this section.
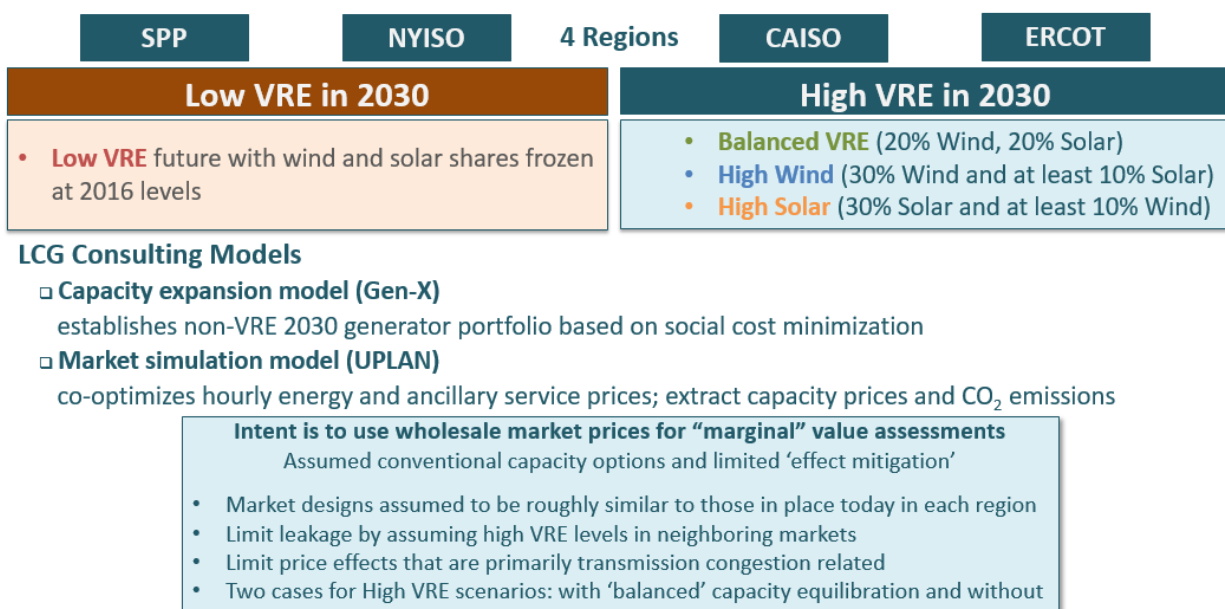
Figure 4 Research Design for Assessment of Wholesale Market Outcomes in 2030

4.1 VRE Penetration Scenarios in 2030

We distinguish between a low VRE penetration scenario that freezes the share of wind and solar generation at 2016 levels, and three scenarios that increase VRE penetration exogenously to at least 40% (all VRE penetration levels refer to the share of annual electricity demand met by VRE before curtailment). The three high VRE scenarios are designed to explore the different price effects of solar and wind. We investigate a balanced scenario that features a 20% share of wind energy and a 20% share of solar energy relative to in-region demand and compare the results with a high wind scenario (30% wind and at least 10% solar) and a high solar scenario (30% solar and at least 10% wind). To reflect the current VRE build-out in some regions, we chose to never reduce future VRE deployment below levels already observed in 2016. We therefore keep the solar penetration at 14% in CAISO's high wind scenario and maintain the wind penetration at 13% in ERCOT's high solar scenario and at 19% in SPP's high solar scenario. The resulting VRE penetration (before curtailment) can thus rise to nearly 50% in select instances.

As price responses are sensitive to broader regional exchanges of electricity, we assume neighboring markets also achieve 40% VRE penetration in the high VRE scenarios. This assumption mitigates potential "leakage" of VRE electricity and associated moderating effects on prices. We assume that regional transmission inter-tie capacity is based on their physical capabilities, including appropriate limits defined by the ISOs in their planning studies, and do not restrict transmission utilization based on historical flow patterns. Similarly, we try to minimize congestion-related price effects by expanding inter-zone transmission limits to keep transmission-related VRE curtailment to less than 3%. VRE curtailment can rise above 3%, however, if driven by overall system constraints rather than congestion. We do not include any cost of curtailment: in effect we assume no incentive for VRE generators to produce power when wholesale electricity prices are below $0/MWh.[12]

All the new solar capacity is modeled as photovoltaics (PV). We represent behind-the-meter PV by assuming 25% of all solar generation is from distributed PV and 75% is from large-scale PV. Distributed PV has a slightly different generation profile compared to utility-scale PV due to differences in the orientation and availability of tracking.[13]

4.2 Capacity Expansion Model

The entry of new power plants and exit of existing generators by the year 2030 is uncertain and requires some modeling choices. To derive a portfolio of non-VRE generators for our four regions we rely on LCG's capacity expansion model and optimization tool Gen-X.[14] Capacity expansion (including the option to retire existing generation) is based on social cost minimization including the variable and fixed cost of all generators and up-front capital costs for new generators. For each scenario, Gen-X is used to find the least-cost combination of generation additions and retirements while satisfying system constraints. System-level constraints in Gen-X include (but are not limited to) planning reserve margins, load and ancillary service requirements, RPS and emission constraints, and area power transfer limits. Due to the lumpy nature of generator expansion and retirement decisions, Gen-X is solved via a mixed integer programming technique. The Gen-X model iterates with the more detailed market simulation model called UPLAN, described below, on an as needed basis. In this analysis, Gen-X was only used to find the expansion plan for non-VRE resources, as the VRE levels were specified exogenously. In each iteration, poorly performing generators are flagged as candidates for retirement in the Gen-X model runs. At the same time, Gen-X checks the planning reserve margin requirement and adds enough new non-VRE units to meet the requirement. Like general generation expansion models, Gen-X allows the user to define capital costs, recovery periods and inflation rates for new technologies to ensure that the capital costs of future units are adjusted for inflation and consistent with other costs. The solution includes the timing and locations of new entrants.

---

[12] We assume that most wind projects will not receive production tax credits by 2030 and disregard additional incentives such as voluntary or mandatory renewable energy credits, or financial PPA arrangements, that would compel VRE generators to schedule electricity at negatives prices.

[13] We leveraged location-specific and load-correlated wind and solar generation profiles based on a 2006 weather year that were compiled by NREL (Hodge, 2013a, 2013b).

[14] For more information see (LCG Consulting, 2017a).

We develop each of the high VRE scenarios using two different approaches based on whether or not the VRE expansion is considered in the development of the non-VRE portfolio. In our **balanced portfolio approach,** which is the focus of the results presented in Section 5, we use the same approach outlined above to develop non-VRE generator portfolios in long-run equilibrium in both the low and high VRE scenarios. That includes VRE induced retirements if generators are unable to recover their fixed and variable O&M costs. We contrast this approach with what we call an **unbalanced portfolio approach** in which VRE additions do not affect the non-VRE portfolio. Several studies, particularly those that deal with technical integration issues of large shares of VRE (Brancucci Martinez-Anido et al., 2016; Brinkman, Jorgenson, Ehlen, & Caldwell, 2016; Deetjen et al., 2016; Frew et al., 2016; GE Energy, 2010, 2014; Hummon et al., 2013; LCG Consulting, 2016; Lew et al., 2013; NYISO, 2010), fix the non-VRE generation portfolio and compare the system's performance with and without large VRE capacity additions. Since the VRE additions do not affect the non-VRE generation portfolio, these studies often lead to significant over-capacity beyond required reserve margins, which can in turn reduce average prices and price variability. Due to the prevalence of this approach in previous studies, we develop scenarios with both the balanced and unbalanced approaches to compare and contrast the results.

The following assumptions can significantly affect the addition and retirement of capacity and are thus briefly explained. We assume that ancillary service requirements increase with VRE penetrations according to the current rules or recent studies of each of our modeled markets. We include emission costs for NO_x, SO_x in NYISO and ERCOT and for CO_2 in CAISO and NYISO based on exogenous projections of permit prices by planning entities in each of our four regions (see appendix). The emissions costs affect the marginal costs of generators and therefore influence the market clearing prices for electricity. Overall load levels determine the demand for existing and new generators; we used the median (P50) forecast of loads by the respective planning agencies. The hourly load profiles and their geographic distribution within the system (bus-level) were adopted from the load profiles published by the ISOs. Finally, the assumed fuel prices that affect generator investment choices and the merit order dispatch are based on NYMEX futures (for natural gas) and EIA forecasts. LCG forecasts differences in natural gas prices near generators compared to Henry Hub based on historically observed relationships (see appendix). Storage additions beyond current regulatory mandates were not considered in the capacity expansion model as we plan to use the simulated prices to evaluate the effect of VRE on the economic viability of different storage configurations in subsequent analyses.

4.3   Security Constrained Unit Commitment and Economic Dispatch Model

After establishing a generation portfolio in each of our scenarios, we subsequently derive hourly electricity price and marginal emission rate series using a security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) tool developed by LCG called the UPLAN Network Power Model.[15] This model co-optimizes energy and ancillary service markets and allows for a large range of input data for load, generation and the transmission network to give the user enough flexibility for mimicking market procedures. The load input data includes the hourly load profile for each balancing

---

[15] For more documentation see (LCG Consulting, 2017b).

authority and demand response functions to emulate market energy management programs. The generator input data covers the physical characteristics (such as size, heat rates, fuel types, minimum up/down time, ramp-rate, forced outage rate, the provided services, etc.) as well as economic characteristics (such as variable and fixed operation and maintenance costs, start-up and fuel costs, bids, etc.) of each individual unit in a region. Solar and wind generation is modeled using hourly generation profiles. Storage and hydro units include additional constraints such as charging/discharging limits, initial inventory, storage size, capacity factor, run of river, etc. For each transmission line, UPLAN models the start and end buses, thermal and emergency capacity ratings, capacity multipliers and physical characteristics such as reactance and resistance to estimate the line losses. For our modeling purposes we used a zonal (rather than nodal) representation of the transmission network.

After determining the available generators and transmission capacities, the model simulates electricity markets in two steps, with both steps addressing transmission-related constraints and the interaction of energy and ancillary service markets. In the first step (SCUC), the model schedules resources to meet loads and ancillary service requirements, while taking into account region-specific operating protocols and transmission constraints, contingencies, and interface limits. Optimal power flow simulation is used to ensure that the selected unit commitment will obey transmission constraints at the zonal level. The final SCUC solution is required to be secure under all specified line outage contingencies. In the second step (SCED), the model dispatches the previously committed generators (as well as any quick-start generators, if required) to meet load. This will be done in the most economic manner possible, based on the generator bids and subject to transmission constraints. This dispatch step determines both the output levels of individual generators, and the transmission line flows. Here the model ensures that the power system is optimally operating within specified constraints, e.g., ramp rates, minimum up times and line capacities. This step also enables the model to calculate the marginal or average transmission losses for serving load from different generators. Using this methodology, the SCED step ultimately determines the energy prices at each bus, zone or hubs as well as ancillary service prices. These steps may be iterated as the energy and ancillary service markets are equilibrated.

The energy and ancillary service prices are subsequently used to simulate rational bids for a capacity market. One consequence of the sequential nature of the capacity expansion modeling followed by the detailed market modeling is that the capacity prices reflect the largest unmet fixed O&M costs of any unit in the market or the largest unmet fixed capital costs and fixed O&M costs of new units built to meet the planning reserve margin in Gen-X. Using UPLAN thus results in congruent energy, ancillary service, and capacity prices assuming the portfolio is stable and unchanging in each scenario. Given the overall uncertainty in 2030 prices that arise from our various fuel price, load and generator characteristic assumptions, we have chosen to limit our geographic resolution in each target region to the zonal level (including 3-6 zones per market) instead of a nodal level.

Based on our unit commitment and economic dispatch model we derive consistent hourly data series for the year 2030 for wholesale energy prices, capacity prices, ancillary service prices (regulation up/down, spinning and non-spinning reserves), and marginal CO_2-emission rates.

4.4   Regional Case Studies

To reflect a range in renewable energy resource endowments, load patterns, and fundamental market characteristics, we have chosen to model four regional case studies: SPP, NYISO, CAISO, and ERCOT.[16]

4.4.1   SPP

The Southwest Power Pool (SPP) encompasses most of North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and small parts of neighboring states. In the heart of America's wind belt, this region had the highest wind penetration in 2016 with an average of 19% in 2016 (ranging from 9-29% in member states) and a cumulative wind capacity of about 16 GW. Solar generation was negligible in 2016 at 0.1% of in-region generation. Similar to Texas, no current regulations require additional solar and wind capacity growth, but project economics are expected to remain favorable for wind and become increasingly favorable for solar as well. SPP does not operate an organized forward capacity market but utilities do have requirements to meet a planning reserve margin. The majority of load is served by vertically integrated utilities in the SPP territory – while some "cost-plus" regulation may lessen the retirement pressures for uneconomic units or emphasize other considerations beyond marginal value in the program design for demand-side resources (Bielen, Burtraw, Palmer, & Steinberg, 2017), we still believe that information on when the incremental costs of meeting another unit of demand, as represented by our wholesale prices, is relevant to many decision-makers in this region.

4.4.2   NYISO

The New York Independent System Operator (NYISO) comprises the state of New York and reflects the lowest share of VRE among our case studies in 2016. Wind supplied 3% of in-state generation (1.8 GW nameplate) compared to 0.8% of solar generation (0.3 GW). The Clean Energy Standard of 2016 requires 50% renewable and nuclear electricity by 2030 and is expected to drive significant new investments into wind and solar capacity over the next decades. Based on NYISO planning practices, we assume a carbon cost of $24/t CO_2e (see Appendix). NYISO operates an organized forward capacity market where utilities procure sufficient capacity to meet a planning reserve margin from generators that bid capacity into to the market.

4.4.3   CAISO

The California Independent System Operator (CAISO) covers most but not all of the state of California and already features significant amounts of VRE. As of 2016, 14% of California's generation was supplied by solar (18.2 GW nameplate capacity), compared to 7% wind generation (5.6 GW). State regulations such as Senate Bill 350 require a further expansion of the state's renewable portfolio standard to 50% by 2030 and recent projections expect 27.5% solar PV and 13.5% wind penetration to satisfy this mandate (the remainder is largely provided by geothermal and some biomass, hydro and solar thermal) (CPUC, 2016). For the year 2030 we have modeled a carbon price of slightly more than $50/t CO_2e for generation within

---

[16] The 2016 VRE penetration numbers are primarily sourced from state-level information provided by the American Wind Energy Association and the Solar Energy Industries Association and are intended to provide rough points of reference. In some instances they may differ slightly from the ISO-footprint penetration numbers.

CAISO based on scenarios of the California Energy Commission.[17] Like SPP, CAISO does not operate an organized forward capacity market, but utilities are required to procure sufficient resources to meet a mandated planning reserve margin. Many utilities meet this with a combination of utility-owned resources and bilateral contracts with generators.

4.4.4 ERCOT

The Electric Reliability Council of Texas (ERCOT) is largely identical with the boundaries of the state of Texas and features the largest amount of wind capacity in the United States with 20.3 GW at the end of 2016 (13% of in-state generation). Solar, in contrast, has a share of only 0.25% with 1.2GW of capacity. No wind, solar or carbon mandates are currently in place to drive further wind and solar deployment by 2030, but favorable project economics for both wind and solar are expected to lead to further renewable capacity expansion. ERCOT is an energy-only market without a formal obligation for utilities to procure resources to meet a planning reserve margin. ERCOT does have high price caps ($9,000/MWh) and utilizes an operating reserve demand curve (ORDC) to signal the value of generation during times of scarcity. ERCOT also is its own interconnection with negligible transmission capacity to other regions.

5. Key Findings

This section highlights the key findings of our modeling efforts, focusing primarily on the results of our balanced capacity portfolio approach that is meant to mimic long-term equilibrium market conditions, unless otherwise noted.[18]

5.1 VRE Growth Results in Modest Net-Retirement of Firm Capacity

The addition of the large amounts of VRE capacity (13-56 GW of solar and 4-35 GW of wind depending on region and scenario) needed to achieve 40% VRE penetration in the modeled year 2030 has implications on the overall capacity portfolio in the four regions, as pictured in Figure 5. As a general trend, we observe an increase in the total nameplate capacity in the high VRE scenarios relative to the low VRE scenario, as wind and solar capacity contribute only a small fraction of their nameplate capacity toward meeting planning reserve margins.[19] The primary explanation for this is the imperfect alignment of expected VRE generation and peak load. Even when VRE generation does align with peak load, the marginal capacity credit for VRE technologies can decrease with increasing penetration levels, as the times of the highest net-load can shift to times when VRE production is low. This is especially pronounced in the high solar scenarios, consistent with past literature (e.g., Denholm, Novacheck, Jorgenson, & O'Connell, 2016; A. Mills & Wiser, 2012; Andrew D. Mills & Wiser, 2013).

---

[17] See the appendix for a comparison of emission costs and sources. Imports into CAISO were modeled with $20/MWh wheeling charges to account for average emission intensity of generation in the rest of WECC.

[18] The raw model output of hourly energy and ancillary service prices, annual capacity prices, and information about the selected generator portfolios is made publicly available on our publication website:
https://emp.lbl.gov/publications/impacts-high-variable-renewable

[19] The average capacity credit for newly installed wind capacity (beyond low VRE levels) is 10-24% (depending on region and scenario), while the average capacity credit for newly installed solar capacity is 8-63%. For more information, see the appendix.

SPP NYISO CAISO ERCOT charts with legend: Solar, Wind, Hydro, Gas-other, Gas-CT, Gas-CC, Other, Coal, Nuclear
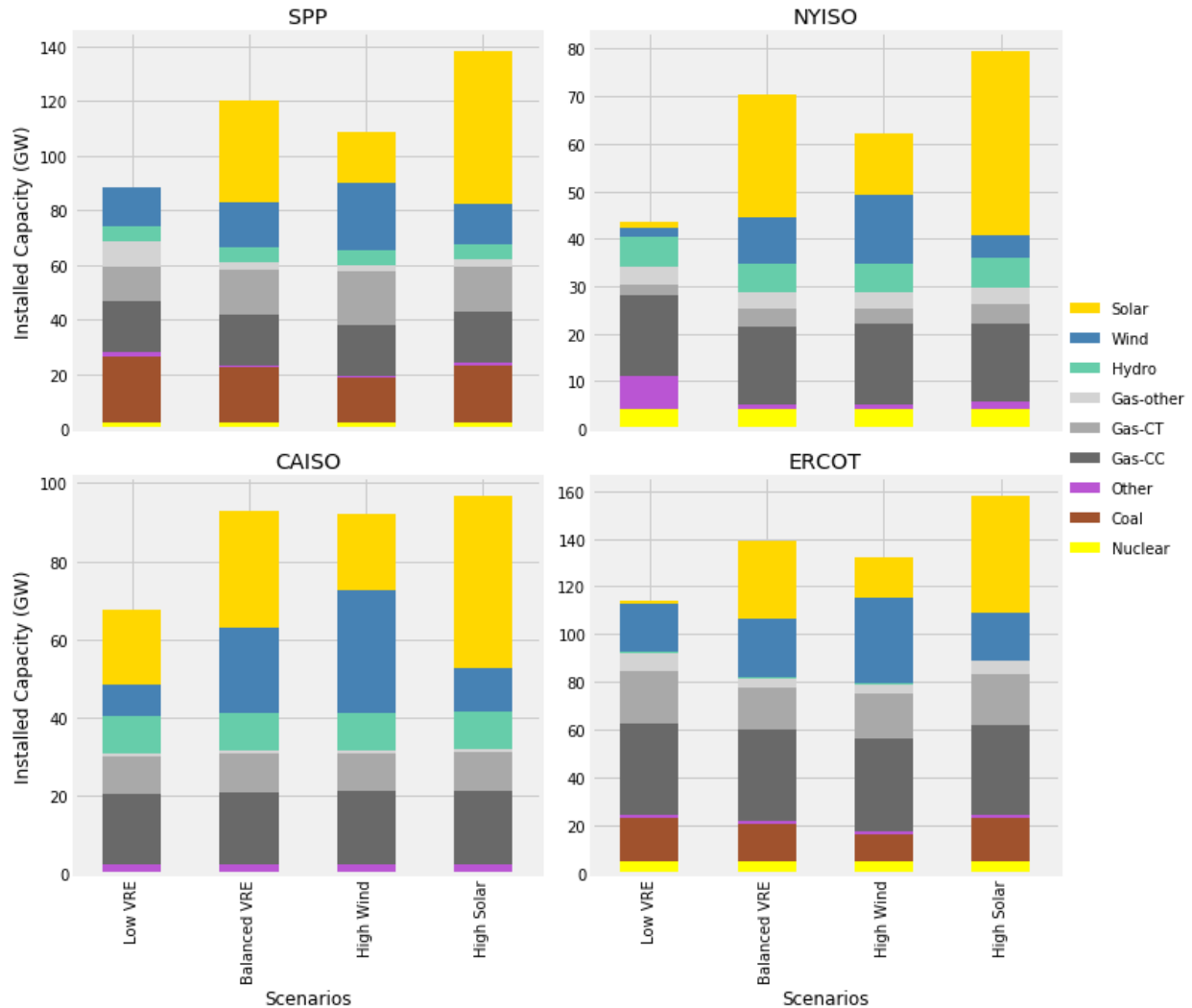
Source: LCG PLATO Data Models

Figure 5 Comparison of Installed Capacity Across Regions and Scenarios

Nonetheless, the VRE expansion leads to modest reductions of non-VRE capacity relative to the low VRE scenario in most regions. Specifically, outside of CAISO, a decrease of 4-16% in non-VRE capacity primarily stems from a retirement of coal, oil and steam turbines. In CAISO, in-state non-VRE capacity actually grows by 2-4% relative to the low VRE scenario, though this is due to modeled retirements of out-of-state generation (represented in the next section as imports) in the high VRE scenarios.[20]

The greatest VRE-induced retirement of firm capacity occurs in ERCOT—the region with the largest amount of firm capacity in the low VRE scenario. While firm capacity is retired in all three high VRE scenarios in ERCOT, the high wind scenario leads to the largest reductions in firm capacity of 13GW (14%). Similar relative reductions in firm capacity can be observed in SPP, again especially under the high wind

---

[20] As a reminder, the **Low VRE** scenario has 2016 VRE penetration levels. The **Balanced VRE** scenario features 20% wind and 20% solar, the **High Wind** scenario features 30% wind and at least 10% solar (or 2016 solar %, whichever is greater), and the **High Solar** scenario features 30% solar and at least 10% wind (or 2016 wind %, whichever is greater).

scenario (8.5GW or 12.5%). In NYISO, we observe a large reduction of more than 5GW in oil capacity.[21] Nuclear capacity remains stable in all regions and does not experience further retirements beyond the retirements modeled in the low VRE scenario. Across most regions and scenarios, we see a modest increase in gas combustion turbine capacity that partially offsets the oil, coal and gas steam turbine retirements.

## 5.2 Energy from VRE Primarily Displaces Coal and Natural Gas Generation

As we assume the hourly load to remain consistent in the low and high VRE scenarios, additional energy produced by new renewable generators in the high VRE scenarios offsets non-VRE generation with a one-to-one ratio, leading to reductions in fossil fuel generation of 25-50%. An exception to this rule applies in the limited cases in which VRE generation is curtailed, namely when VRE and some non-VRE must-run generation exceeds total load levels. This occurs most prominently in the high solar scenarios, leading to an average (not marginal) VRE curtailment ranging from 3% of all VRE generation (CAISO) to 8% (ERCOT)[22], but also to a lesser extent in the balanced and high wind scenarios in ERCOT and SPP. The total VRE generation represents 38-44% of in-region load after accounting for curtailment.

Figure 6 highlights the resulting deep reductions in combined cycle natural gas generation across all regions and scenarios and lower coal generation levels deriving, in part, from the coal capacity retirements in SPP and ERCOT discussed in Section 5.1. In NYISO and to some extent in CAISO the new VRE generation reduces the annual net-import of electricity from outside the region as well, while SPP becomes a net-exporter of electricity in the high solar scenarios.

---

[21] Some of the oil capacity in the low VRE case only has single-fuel capabilities and all of those plants are retired. The remaining oil generators have in fact dual-fuel capability.

[22] Our average solar curtailment numbers for CAISO are somewhat lower in comparison to other recent studies (e.g., 9% in Energy and Environmental Economics (2014) and Schlag et al. (2015). Differences could be explained by a more flexible generation portfolio or increased transmission utilization that is limited by physical capabilities instead of historical flow regimens. Our average VRE curtailment numbers are however comparable to the 3-5% average curtailment described by Lew et al. (2013), 4-6% in Bloom et al. (2016) or 1-6% in Bistline (2017).
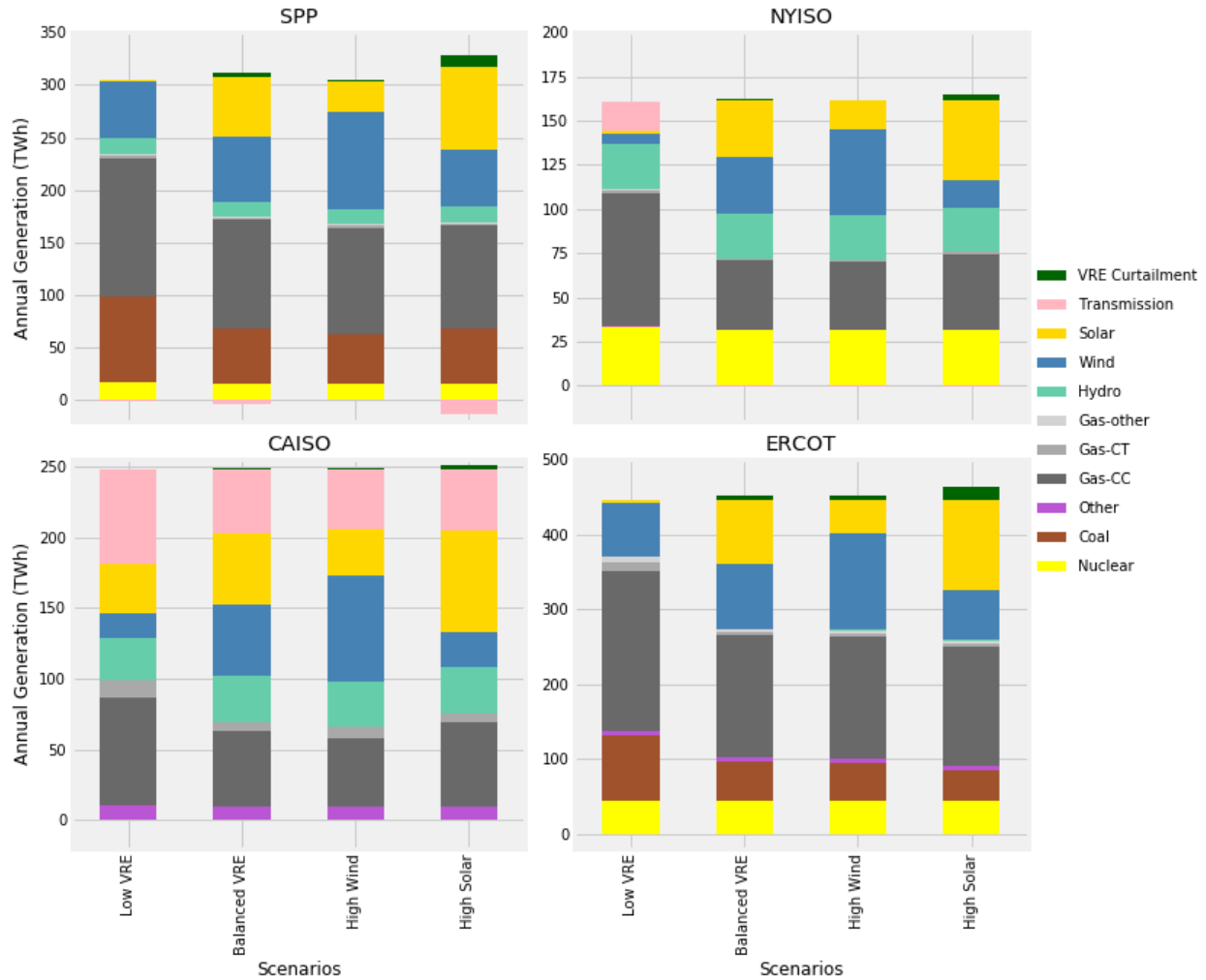
Source: LCG UPLAN-NPM simulation

Figure 6 Comparison of Annual Generation Across Regions and Scenarios

5.3 VRE Changes the Marginal Carbon Emissions Rate

Our modeling finds a reduction of total annual electric-sector carbon emissions in the high VRE cases of 21% to 47%, relative to the low VRE scenarios, depending on region and high VRE scenario. In absolute terms, the carbon savings are the lowest in NYISO and CAISO, two regions in which we assume a carbon penalty price across all scenarios. Furthermore, we find that the high VRE scenarios lead to a decrease in the marginal carbon emission rates (i.e., the emission rate of the marginal generator) relative to the low VRE scenario in each region. Across the year the marginal emission rates drop by 6-21% in ERCOT as a lower end and by 28-37% in SPP as a higher end in the high VRE scenarios relative to the low VRE scenario (using the load-weighted average).

Particularly relevant for decision makers interested in designing programs to reduce emissions is that high VRE scenarios also shift the timing of when high marginal carbon emission rates occur and the frequency of periods with very low marginal emissions rates. Figure 7 shows the mean diurnal (24h)

marginal emission rate profiles by scenario and region, derived from the energy and ancillary service market, and averaged over all weekday hours of the year.
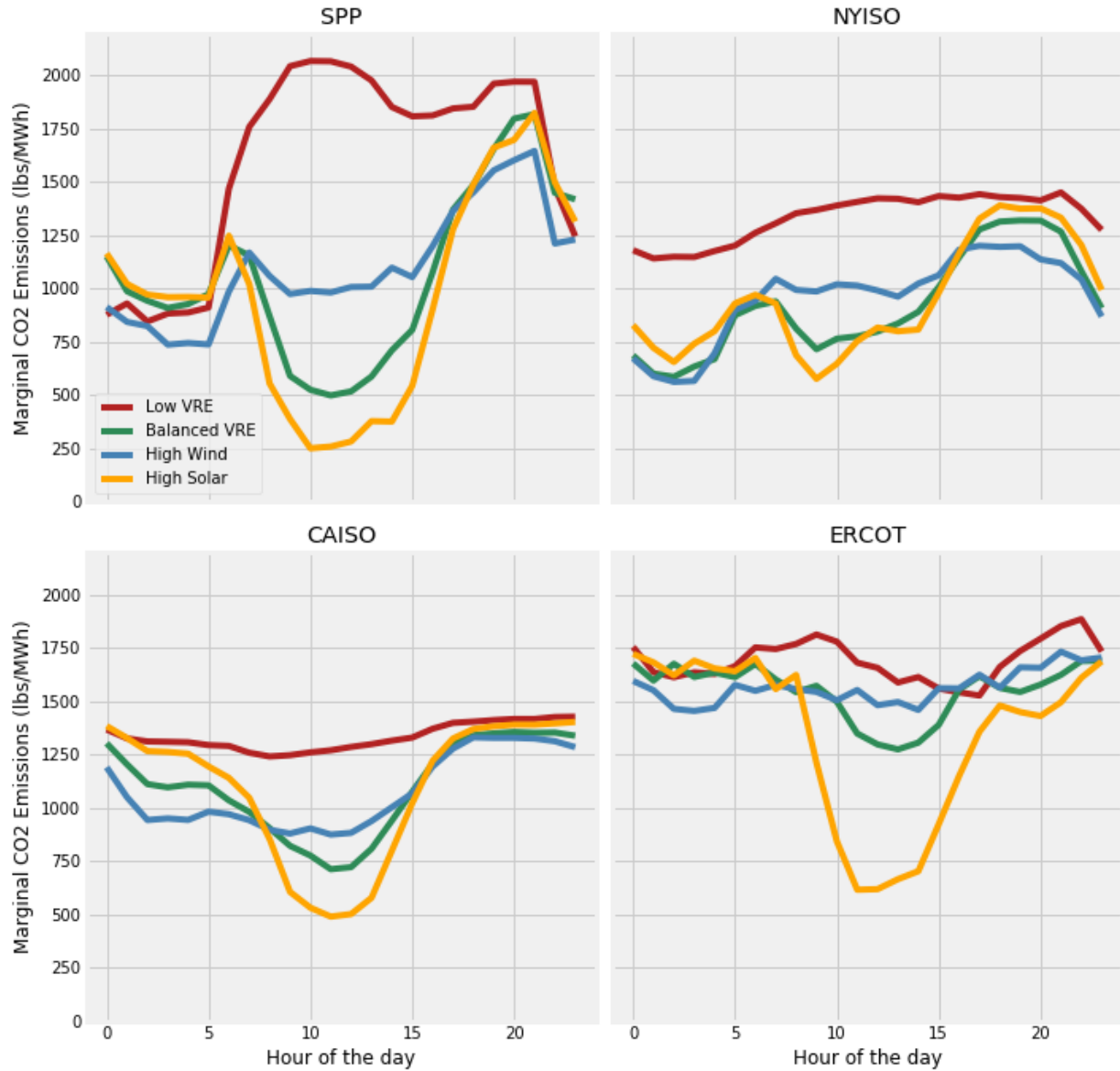
Source: LCG UPLAN-NPM simulation

Figure 7 Diurnal Mean of Marginal Carbon Emissions Profiles for Weekdays Across Regions

The most dramatic shifts can be seen in the high solar scenarios across all regions, with marginal emission rates decreasing by 750-1750lbs/MWh relative to the low VRE scenario over the middle of the day. Electricity generation from wind impacts the diurnal emission rate profile as well, but not nearly to the same degree, as wind generation tends to be less correlated across plants and does not follow regular diurnal cycles to the same extent as solar generation. With the exception of SPP, the high wind scenarios show primarily a downward shift in emission rates while still generally resembling the original shape of the low VRE marginal emission rate profiles.

The hours with a marginal carbon emissions rate of zero increase with high VRE generation: 5% of all hours in the CAISO balanced and high wind scenario have zero marginal carbon emissions, whereas on the high end, 31% of all hours in the SPP high solar scenario have zero marginal carbon emissions as depicted in Figure 8.[23] Increasing load in these periods would result in no additional carbon emissions.
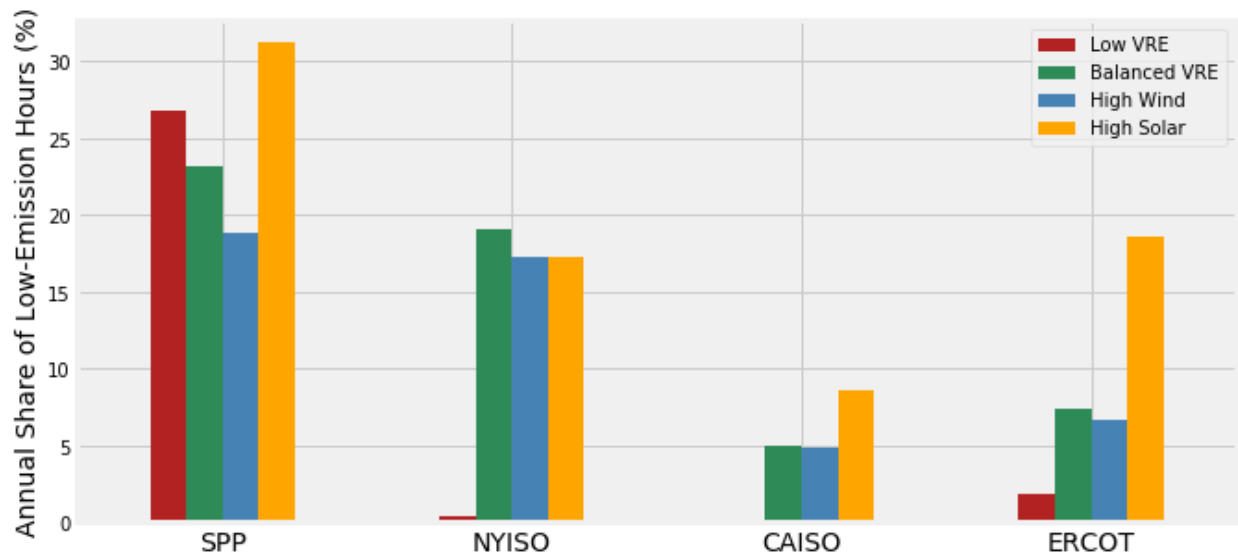
Figure 8 Share of Hours with Marginal Carbon Emissions at 0lbs per MWh

5.4 Annual Average Energy Prices Decline with Increasing VRE Penetration

The following discussion in Sections 5.4 to 5.7 is limited only to the ISO-wide hourly energy price component of wholesale electricity prices, whereas Sections 5.8 and 5.9 address trends in ancillary service and capacity prices.

We find that hourly energy prices differ across scenarios within a region as varying types of generation with different operational costs become more or less common on the margin of the supply curve, and they vary across regions in part due to different electric supply mixes, load patterns, and assumed emission costs. Carbon costs in NYISO and especially in CAISO explain the generally higher price levels in those ISOs relative to SPP and ERCOT.

Despite these market-specific differences, we find similar price effects with increasing VRE penetrations across the four regions. In particular, Figure 9 highlights the reduction in average annual hourly energy prices as the share of wind and solar rises relative to the low VRE baseline of 4-21%. Depending on region and high VRE scenario, the load-weighted average annual energy price decreases by $5 to $16/MWh. The strongest reduction occurs in NYISO, where average prices decline by nearly 40% from $43/MWh to around $26/MWh, followed by CAISO with price declines from $58/MWh to $42-44/MWh. ERCOT and

---

[23] The reduction in low-emission hours in SPP between the low VRE and the high wind scenario can be explained by newly built efficient gas units in SPP that substitute for low-carbon imports.

SPP's price reductions from the low $30s/MWh to the high $20s/MWh are less pronounced in absolute terms but still account for 15-25% relative to the low VRE baseline. In NYISO, CAISO, and SPP the strongest total price declines arise in the high solar scenario, while ERCOT has the largest price reduction in the wind scenario.
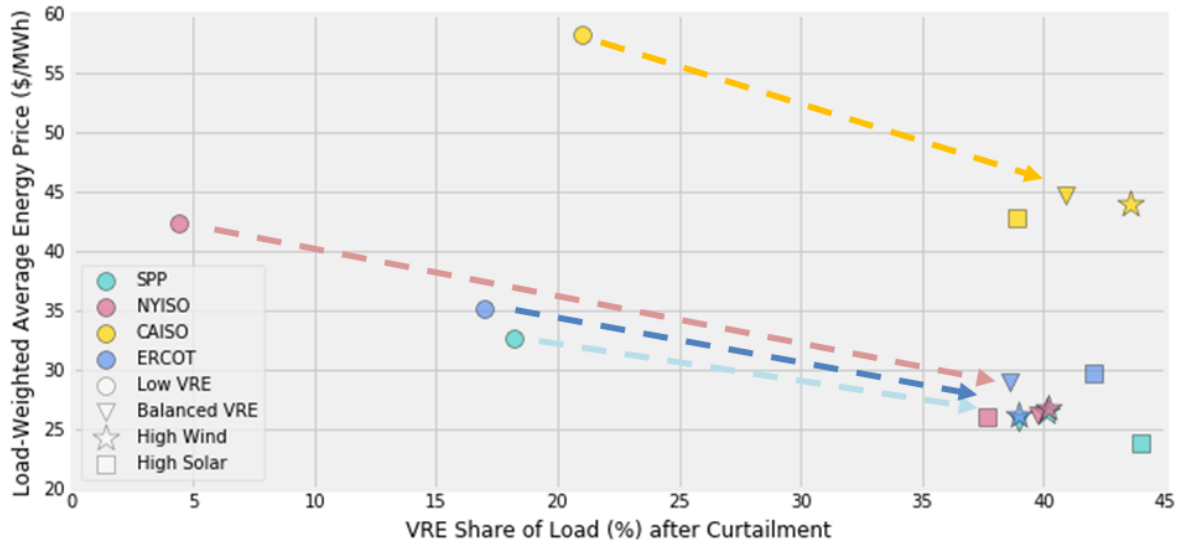
Figure 9 VRE Share of Load vs. Load-Weighted Average Energy Prices by Region

Given that the four regions have different starting levels of VRE penetration in the low VRE scenario (ranging from 4% in NYISO to 21% in CAISO) it makes sense to look at the average reduction in load-weighted energy prices for each additional percentage point in VRE penetration. Figure 10 highlights the normalized VRE effect and shows declines by $0.2-0.9/MWh per additional percentage of VRE penetration (or $0.2-$0.8/MWh when using the VRE potential (pre-curtailment) in the denominator). This overall range of the VRE price effect is similar to the established literature of comparable modeling efforts for the United States, that describes a decline by $0.1-$0.8/MWh per additional VRE % (Wiser et al., 2017).

CAISO's electricity prices are reduced the most per additional percentage VRE penetration, especially in the high solar scenario, in part due to the large cost savings associated with high carbon penalties that occur over relatively little incremental VRE growth (compared with NYISO). In contrast, the high wind scenario leads to the strongest price effect in ERCOT. SPP and NYISO have similar price effects across each VRE scenario. Perhaps the most significant impact of overall reductions in average annual energy prices would be the reduced profitability of inflexible generators that are fully exposed to those prices, including solar, wind, and nuclear plants in particular.
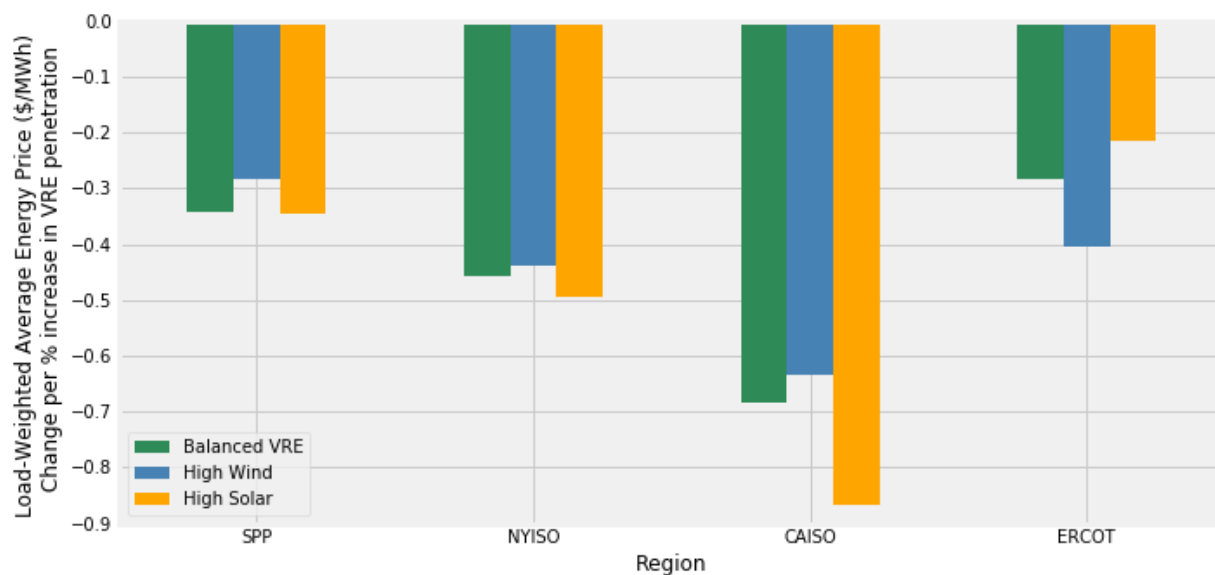
Figure 10 Energy Price Change with Increasing VRE Penetration Across Regions

5.5 Low Energy Prices Become More Frequent as VRE Increases

In addition to the change in average annual energy prices, high VRE penetrations also change the distribution of prices over the course of the year, as shown in the price duration curves of Figure 11. Most notably, we see a substantial increase in the frequency of low-priced hours, but less of an impact to the hours with the highest prices.

Very high-priced hours are relatively uncommon in both low VRE and high VRE scenarios, though the magnitude of the highest prices increases in the high VRE cases relative to the low VRE scenario (up to peak prices of $137/MWh vs. $77/MWh in NYISO, $191/MWh vs. $56/MWh in SPP and even $9000/MWh vs. $483/MWh in ERCOT, due to the ISO's Operating Reserve Demand Curve (ORDC) that aims to ensure price-revenue sufficiency for all generators in an energy-only market). In NYISO, the shape of the overall price distribution changes the least and prices are primarily shifted downwards in most hours by $10/MWh to $25/MWh. Other regions, however, feature a more pronounced 'price cliff', where hours with very low prices become more common, particularly in the high solar scenarios.
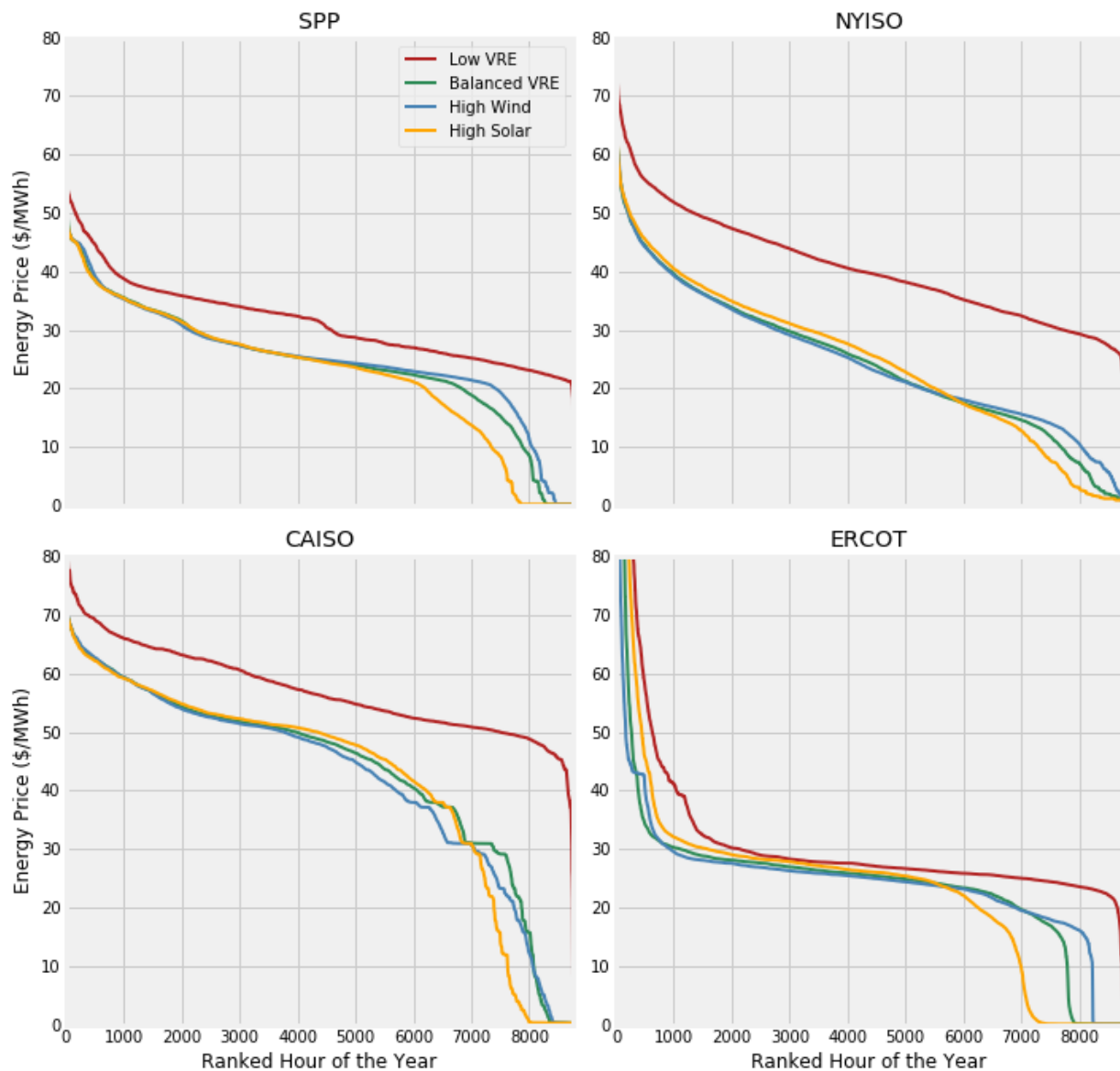
Source: LCG UPLAN-NPM simulation

Figure 11 Energy Price Duration Curve Across Regions (High Price Outliers not Included)

Figure 12 compares the complete absence of hours with energy prices below $5/MWh in the low VRE scenarios in all regions with the substantial increase of such hours in the high VRE scenarios, where they represent between 2.5% and 19% of all hours of the year. In the extreme case of ERCOT, up to 1300h or 15% of the year are found to be at $0/MWh. Low prices are much more frequent in ERCOT in part due to the lack of interconnection capacity with neighboring regions.

The ubiquity of such low-priced hours has significant impacts on all participants in the electricity market, which motivates further exploration of the impact of high VRE scenarios on electric sector decisions. The low prices signify that generation during those hours has very little value. Flexible generators that can ramp down during low-priced hours can lower their variable fuel costs, while inflexible generators will

sell power at a loss. The low prices also indicate that there is very little cost to serving more load at these times. This offers an important opportunity for measures that can make use of cheap electricity such as deferrable loads like electric water heaters, charging of stand-alone or transportation-related storage devices, load-shifting, or intermittently-run advanced forms of commodity production.
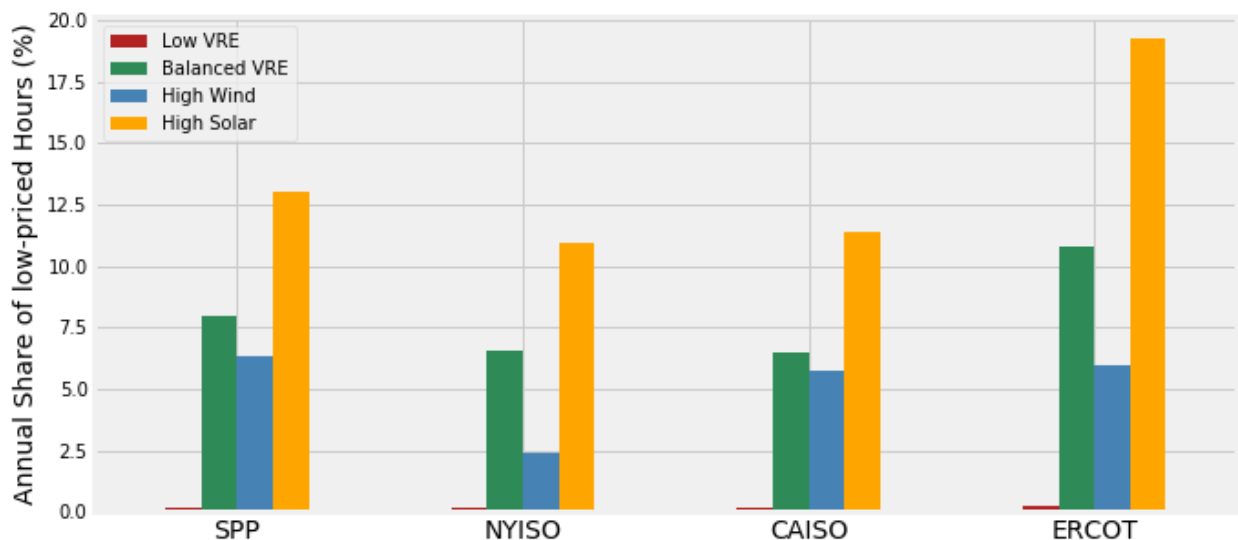
Source: LCG UPLAN-NPM simulation

Figure 12 Annual Share of Hours with Energy Prices Below $5/MWh

5.6 Diurnal Price Profiles Change under High VRE Scenarios

Beyond the reduction in average prices and the increased frequency of low-priced hours we find categorical changes in the diurnal price profiles with the introduction of large shares of VRE. Figure 13 shows the mean diurnal (24h) energy price profiles by scenario and region, averaged over all weekday hours of the year.

The most dramatic shift can be seen in the high solar scenarios across all regions, when prices decrease by $25-$40/MWh relative to the low VRE scenario over the middle of the day. Those price-decreasing effects do not necessarily have the largest magnitude in the summer at peak solar production, but occur, for example, in CAISO during the spring season when overall electric demand is lower and hydropower output is substantial (the price-decreasing effect of the solar generation is actually the smallest over the summer months in CAISO, as higher load-levels and lower non-VRE generation compensate for the solar production increase). In fact, across all regions, the solar price-effect is obvious over more hours in the spring than in the summer.
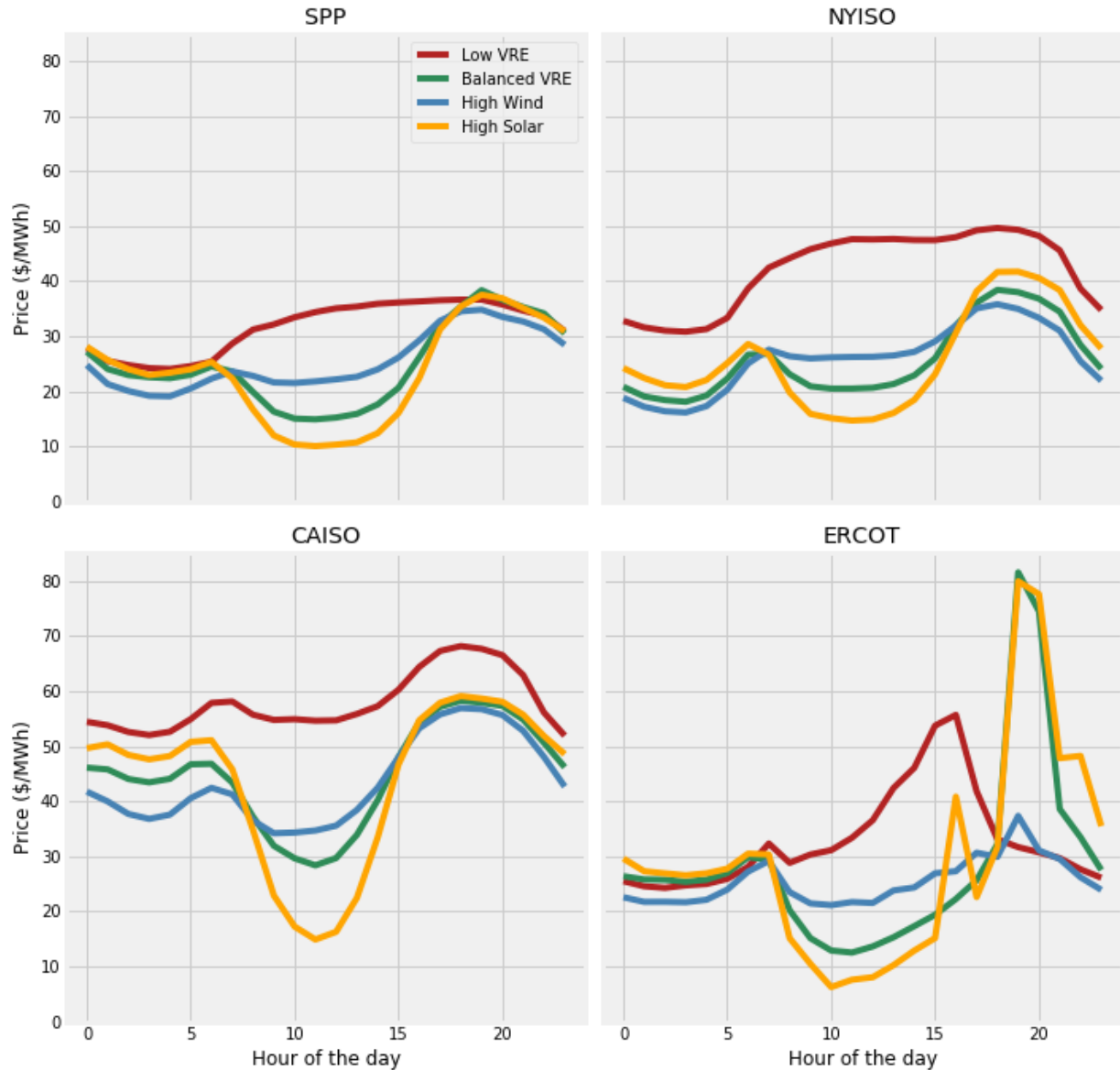
Source: LCG UPLAN-NPM simulation

Figure 13 Mean Diurnal Energy Price Profiles for Weekdays Across Regions

Electricity generation from wind impacts the diurnal price profile as well, but not nearly to the same degree, as wind generation tends to be less correlated across plants and does not follow regular diurnal cycles to the same extent as solar generation. The high wind scenarios shown in Figure 13 do still have some resemblance to the solar-induced "duck curve", as even these scenarios contain at least 10% solar energy.

The annual average price profiles mask some of the seasonal variation that we already alluded to. In the high wind scenario in CAISO, early morning prices fall by $25/MWh in the spring relative to the low VRE scenario, compared to price reductions of only $10/MWh in the fall and winter. Similarly, prices in the high wind scenario for NYISO decline by $20/MWh in the morning hours of spring but only $5/MWh in

the summer. In another example from NYISO, afternoon prices decrease by $30/MWh in the solar scenario relative to the low VRE scenario in the spring and summer, but only $15/MWh in the fall. For ERCOT, the largest difference in mean prices is primarily driven by a few very high-priced hours. The largest seasonal contrast between low and high VRE scenarios occurs in the early evening in the balanced and high solar scenarios, where prices increase by a factor of 7 from $30 to over $210/MWh in the summer, but only $5/MWh in the winter.

Overall diurnal price peaks tend to occur in the early evening hours across most seasons and regions and remain at levels similar to the low VRE scenario (with the exception of the solar and balanced scenario in the summer in ERCOT). However, the peaks in the high VRE scenarios are consistently more concentrated in the early evening hours, relative to the broader peak periods in the low VRE scenario. Another interesting exception to the typical impacts is the substantial evening price reductions in the high wind scenario in the winter in NYISO that lead to a peak price shift from 7 pm in the evening to 9 am in the morning.

These changing diurnal price profiles highlight the value in adapting strategies for load-based resources (e.g., focusing on evening load reductions through residential or street lighting energy efficiency measures or favoring managed residential electric-vehicle charging to not further exacerbate evening peaks), and stress the benefit of flexible, complimentary generation resources.

5.7 Energy Prices Become More Volatile as VRE Increases

We have shown that average annual energy prices decrease and that average diurnal price profiles shift depending on the VRE resources that are introduced to the generation portfolio. A further change explored in this section is an increase in the general volatility of energy prices at higher VRE levels, even after accounting for seasonal and hourly price patterns.

Figure 14 examines price volatility at the diurnal level and depicts the 5th and 95th percentile of prices for any given hour in the spring season in CAISO for our four scenarios, though similar observations can be made in other seasons and regions.

We see that in the low VRE scenario prices for a given hour tend to follow a relatively narrow band of $5-$10/MWh around the seasonal mean diurnal price (on weekdays) without substantial deviation over the course of the day. In contrast, the high wind scenario shows a substantial widening of this price collar to $20-$30/MWh for most hours, indicating that energy prices in the morning may be at zero on some days while prices may reach up to $55/MWh on other days. The price collar is not quite as wide over all hours in the balanced and solar scenarios, but still represents a large increase over the low VRE scenario.
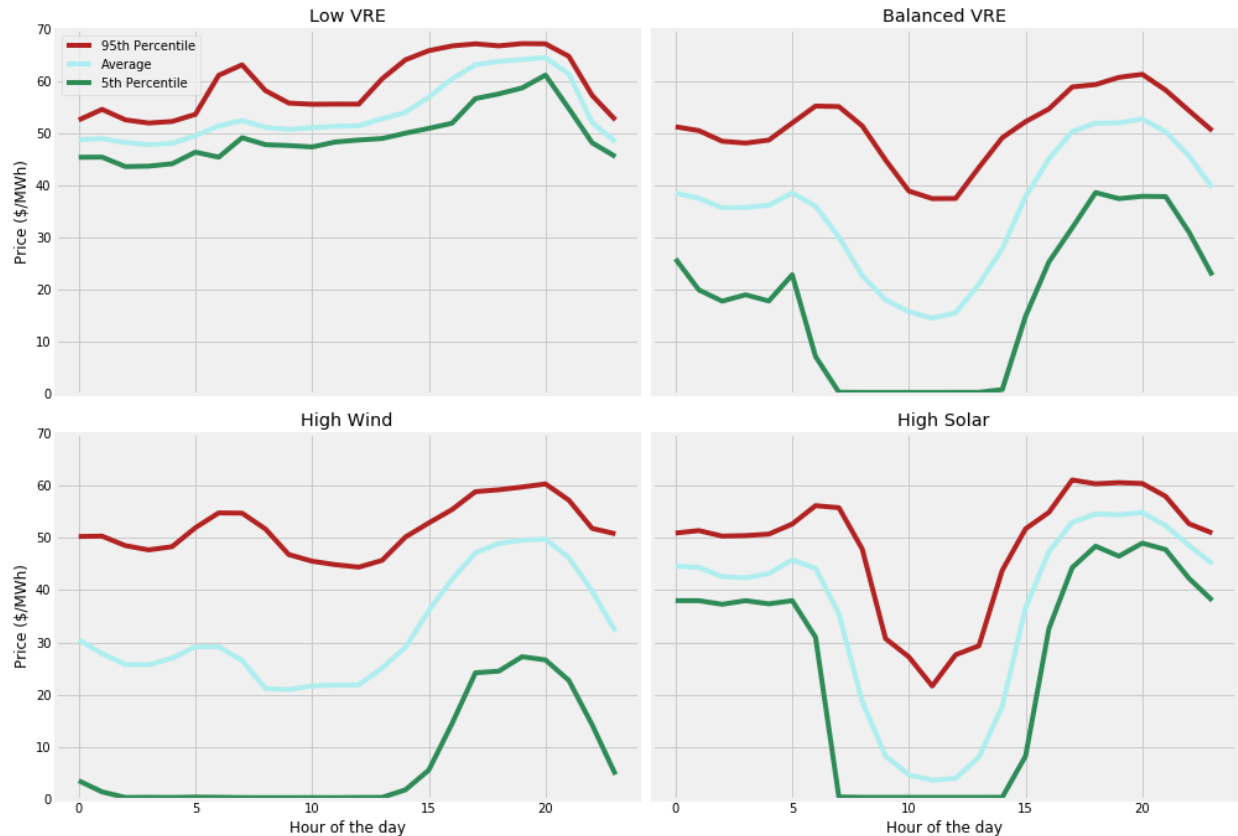
Source: LCG UPLAN-NPM simulation

Figure 14 Range in 5th to 95th Percentiles of Diurnal Energy Prices for Weekdays in Spring in CAISO

Figure 15 depicts a standardized metric of price volatility to facilitate cross-regional comparisons and to highlight the large increase in price variability with the introduction of more VRE in all ISOs. The coefficient of variation (depicted in bars) represents the standard deviation of energy prices divided by the mean energy price to account for different average price levels across regions. This metric combines both steady, repeatable variations from the annual average price (e.g., price swings induced by the solar diurnal profile) and more random fluctuations from the annual average that do not follow a regular pattern (e.g., price swings induced by a swelling gale).

Because this measure captures total variation, we find the largest increase in the overall price variability to occur in the high solar scenarios, even though the high wind scenarios resembled a wider price-collar as discussed previously. The high price volatility in ERCOT stands out and can be attributed primarily to a few very high-priced hours ($1000-$9000/MWh) that are a result of the ISO's ORDC mechanism.
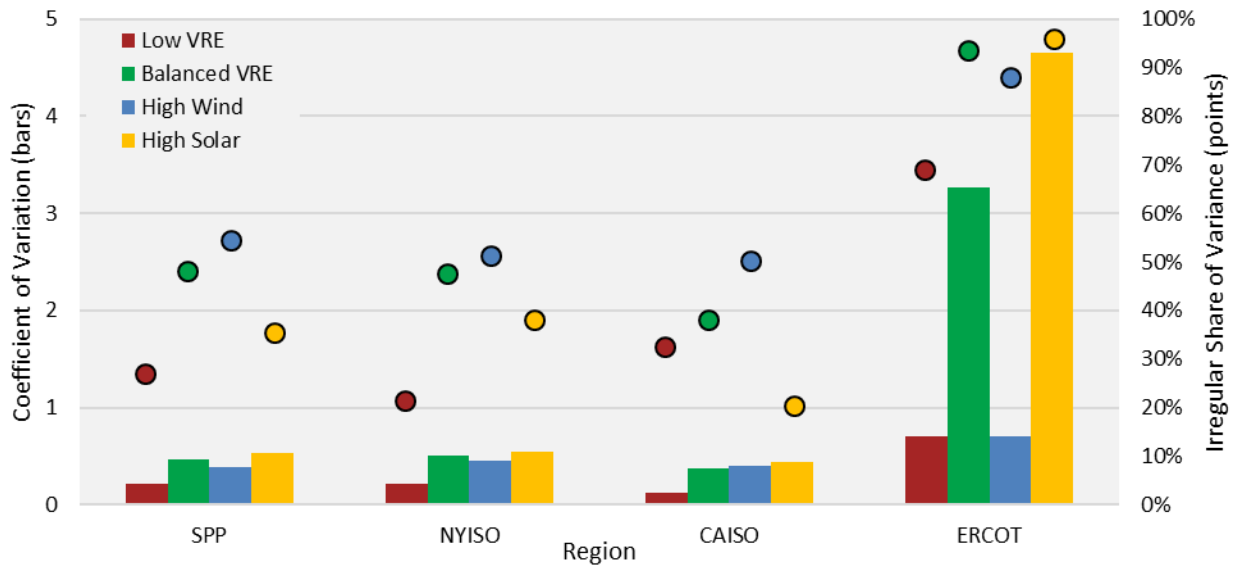
Figure 15 Coefficient of Variation and Irregular Fraction of Variance of Energy Prices Across Regions

Figure 15 also compares the overall fraction of energy price variance that can be explained by regular seasonal, diurnal, and weekday patterns with the fraction of variance not captured by these regular patterns (defined as **irregular share of variance**). We find that overall irregular variance in prices (points) tends to increase in the high VRE scenarios when compared to the low VRE base case. The high solar scenario in CAISO stands as the one exception where the irregular fraction of price variance decreases relative to the low VRE scenario. The greatest increase in the irregular price variance is associated with the high wind scenarios, with the exception of ERCOT where irregular variance is much higher due to the ORDC mechanism. While the high solar scenarios increase the overall variance in prices, 60-80% of total price variance in the high solar scenarios can be explained with periodic patterns (outside of ERCOT), compared to only about 50% in the high wind scenarios.

This increase in price volatility, coupled with the increase in irregularity of prices in most high VRE scenarios, has important effects on other electricity market participants. Stronger price variability and irregularity will favor flexible resources that can start and stop frequently and on short notice, including storage. The increase in irregularity of prices may also make typical time-of-use rate designs less effective at eliciting response from elastic demand during the times of the greatest system needs and instead favor more flexible designs like the residential "real-time pricing" offers available in Texas (Griddy, 2018), or the "variable peak pricing" program implemented at Oklahoma Gas & electric where the peak period price varies from day-to-day based on system conditions (U.S. Department of Energy, 2013). In contrast, traditional baseload generators or very inelastic demand may find it difficult to respond to either regular or irregular price changes.

5.8 Ancillary Service Prices Increase as VRE Penetrations Grow
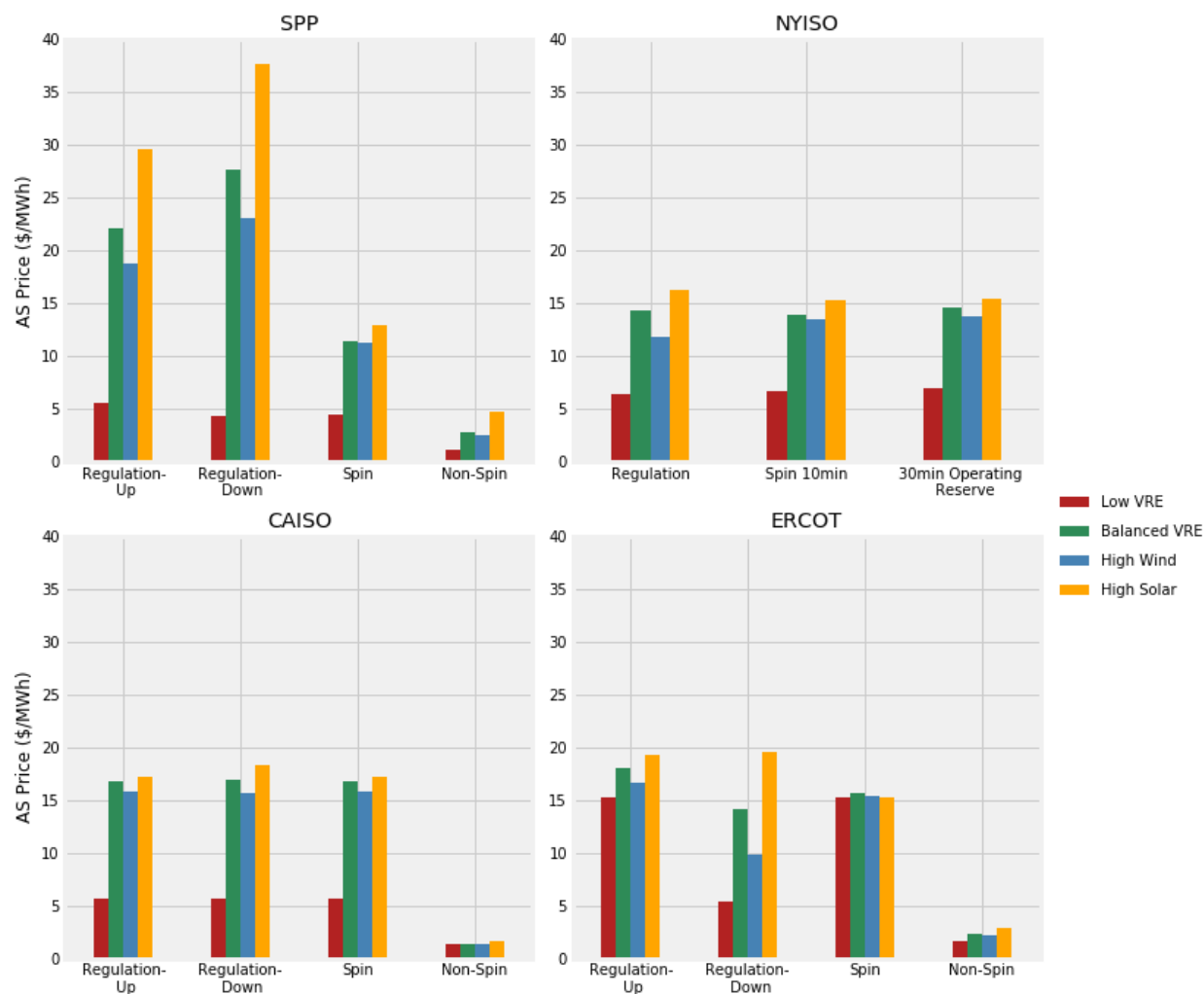
Source: LCG UPLAN-NPM simulation

Figure 16 Average Ancillary Service Prices Across Regions

In addition to energy prices we have modeled ancillary service (AS) prices in each region and Figure 16 shows the simple annual average price by service type. In all high VRE scenarios, average AS prices are higher than in the respective low VRE scenarios and increase for all regulation and spinning products by a factor of 2 to 8 to $15-$38/MWh. Non-spinning reserves prices also increase with VRE penetration, but remain at much lower levels ($1-$5/MWh).[24]

Differences also exist in terms of the frequency of high-priced outliers, in particular for regulation-down products, reaching maximum prices up to $100/MWh in NYISO, $200/MWh in SPP and CAISO, and even nearly $4000/MWh as one outlier in ERCOT's high solar scenario. This can be explained by the high opportunity costs to provide ancillary services for fossil generators that would otherwise be shut down at times of low net-loads (Ela, Kirby, Navid, & Smith, 2012). As shown in Figure 17, regulation-down prices

---

[24] For reserve assumption, see appendix tables.

above $25/MWh are much more common in the high VRE scenarios relative to the low VRE scenarios. In all regions the high solar scenario leads to the largest increase in such high-priced hours (up to 40% of the year in SPP).
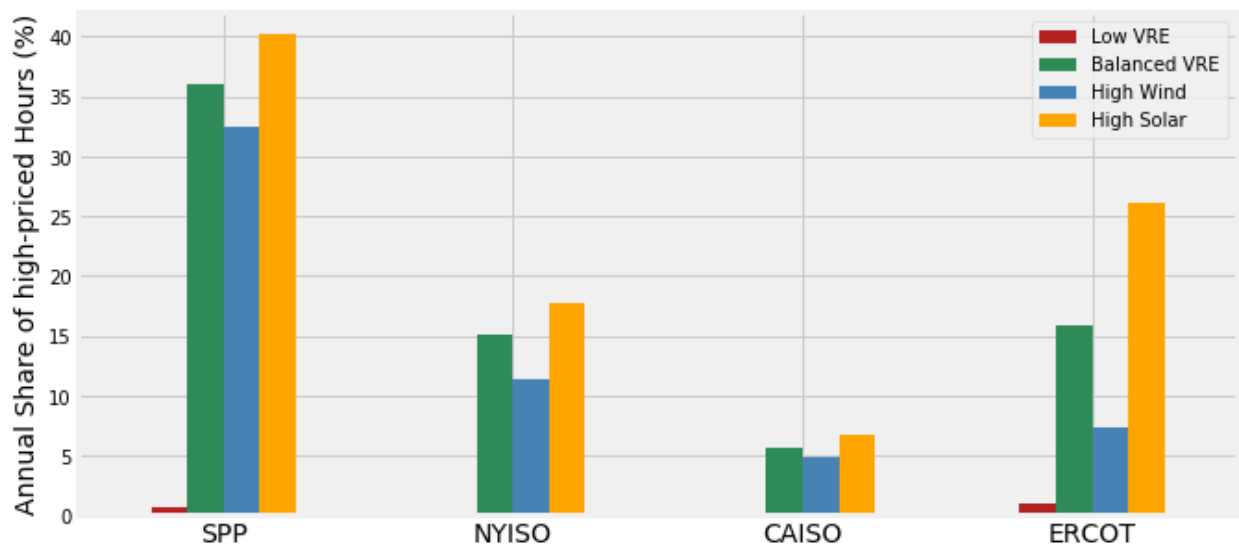
Figure 17 Share of Hours with Regulation-Down Prices Above $25/MWh

Furthermore, diurnal AS price profiles often significantly change with increasing VRE penetration as does their volatility around a given average hourly price level. For example, the high solar scenarios often lead to an increase in the price for regulation-down in the middle of the day relative to the prices in the low VRE scenarios across all regions.

It is important to recognize that we have not allowed VRE generators to participate in the AS market in our modeling results (e.g., by providing regulation-down through voluntary curtailment or by reducing average generation slightly to have headroom for regulation-up services), nor have we included storage resources in our capacity-expansion runs. The overall ancillary service market is relatively shallow and is unlikely to be able to provide substantial amounts of revenue for a majority of energy market participants. Nevertheless, these higher prices suggest increased opportunities for various resource types to provide ancillary services including VRE, "shimmy" demand response (Alstone et al., 2016), storage or faster ramping products.

5.9   Mixed Capacity Price Signals as VRE Increases

Figure 18 examines the annual average capacity prices that allow all competitive generators (i.e., excluding generators that retire) to recover their ongoing fixed and variable operation and maintenance costs and the annualized capital costs of new CCGTs and CTs beyond the revenue earned in the energy and ancillary service markets. Our capacity prices reflect the additional revenue needed to ensure that generators required to meet the planning reserve margin cover their costs in a consistent manner across regions. But, due to the differences in resource adequacy policies, they do not necessarily mimic how

these costs would be recovered in each of these regions.

No strong patterns emerge across regions in how VRE additions impact such capacity prices. In SPP, ERCOT and NYISO, the high VRE scenarios tend to be associated with higher prices, whereas capacity prices decrease in CAISO with increasing VRE penetrations. These results are somewhat sensitive to how much of the existing, older, less-efficient, and price-setting generation capacity happens to be retired by Gen-X at a particular forecast load level with the introduction of large amounts of VRE capacity.
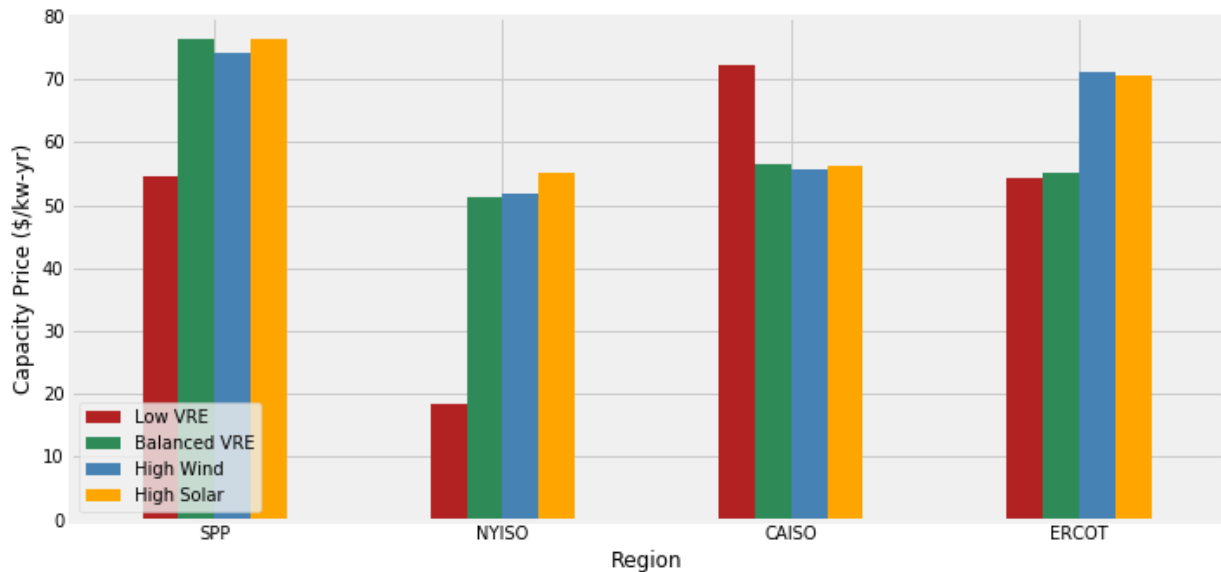
Source: LCG UPLAN-NPM simulation

Figure 18 Average Annual Capacity Price Across Regions

Looking at annual average capacity prices masks, however, some interesting dynamics that become apparent when looking at changes to the temporal and seasonal profile of the top 100 net-load hours (the hours primarily driving the need for new capacity), as described in Figure 19. In contrast to the low VRE scenarios where top hours are highly concentrated over a few days, the high VRE scenarios tend to spread the top net-load hours over a broader set of days, especially in the high solar and balanced VRE scenarios. For example, ERCOT's top 100 net-load hours are clustered on 22 days in the low VRE scenario, but are spread over 45 days in the high solar scenario. Across all regions, the high wind scenarios (which have at least 10% solar and 30% wind) are most effective in reducing peak-net load levels, but contribute less to the spreading of peak-net load hours over a larger set of days throughout the year. Regional differences are also pronounced: CAISO sees little change with increasing VRE penetrations in how the top net-load hours are clustered over the year, while SPP, NYISO and especially ERCOT see a wider distribution over multiple months (from June to October, depending on the region).
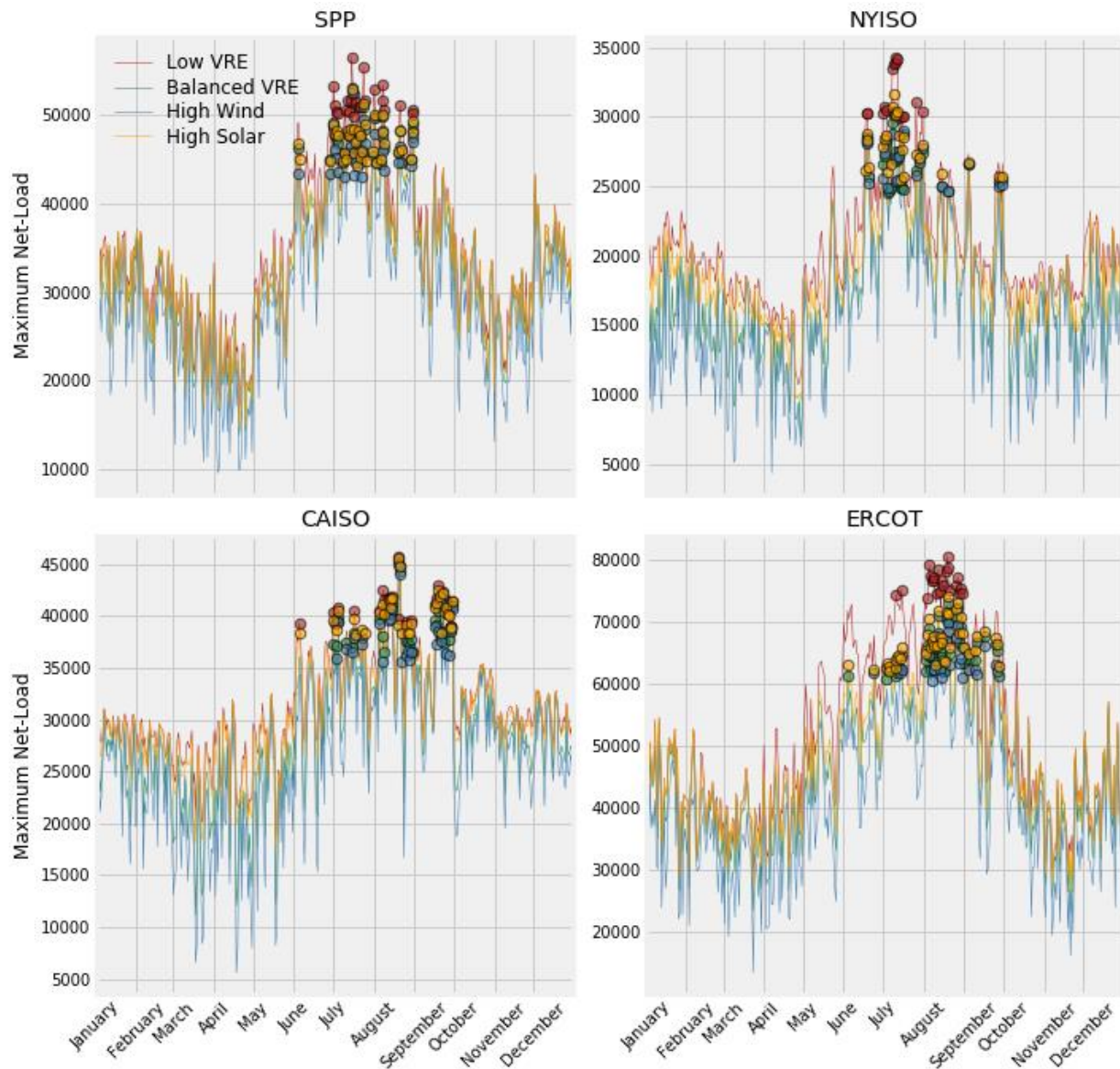
Figure 19 Daily Maximum Net-Load (lines) and Top 100 Net-Load Hours (dots)

While peak-net load hours may occur over more days at high VRE levels, they appear to concentrate over fewer hours in the evenings. Figure 20 shows the likelihood that any given hour over the course of the day is among the top 100 net-load hours. Across regions, peak net-load hours tend to occur within a narrower band of hours in the high VRE scenarios compared to the low VRE scenario (~5h vs. ~10h), and those hours are pushed later into the evening (5pm-10pm vs. 11am-9pm). These "skinny peaks" become especially common with increasing solar penetration. The peak net-load hours shift the least in the CAISO region since the low VRE scenario already includes 13% solar.

The increased solar share in comparison to the low VRE baseline contributes to the shift towards later peak net-load hours even in the high wind scenarios (that feature 30% wind and at least 10% solar). If only wind were to be considered in the net-load in NYISO, for example, the distribution of the top 100

load-minus-wind hours would instead show a minor shift towards earlier hours of the day. This small shift from 30% wind is, however, more than fully compensated by the larger effect of just 10% solar generation pushing the net-load peaks later into the evening. As a result, a shift toward later peak net-load hours occurs in NYISO even the high wind scenario.
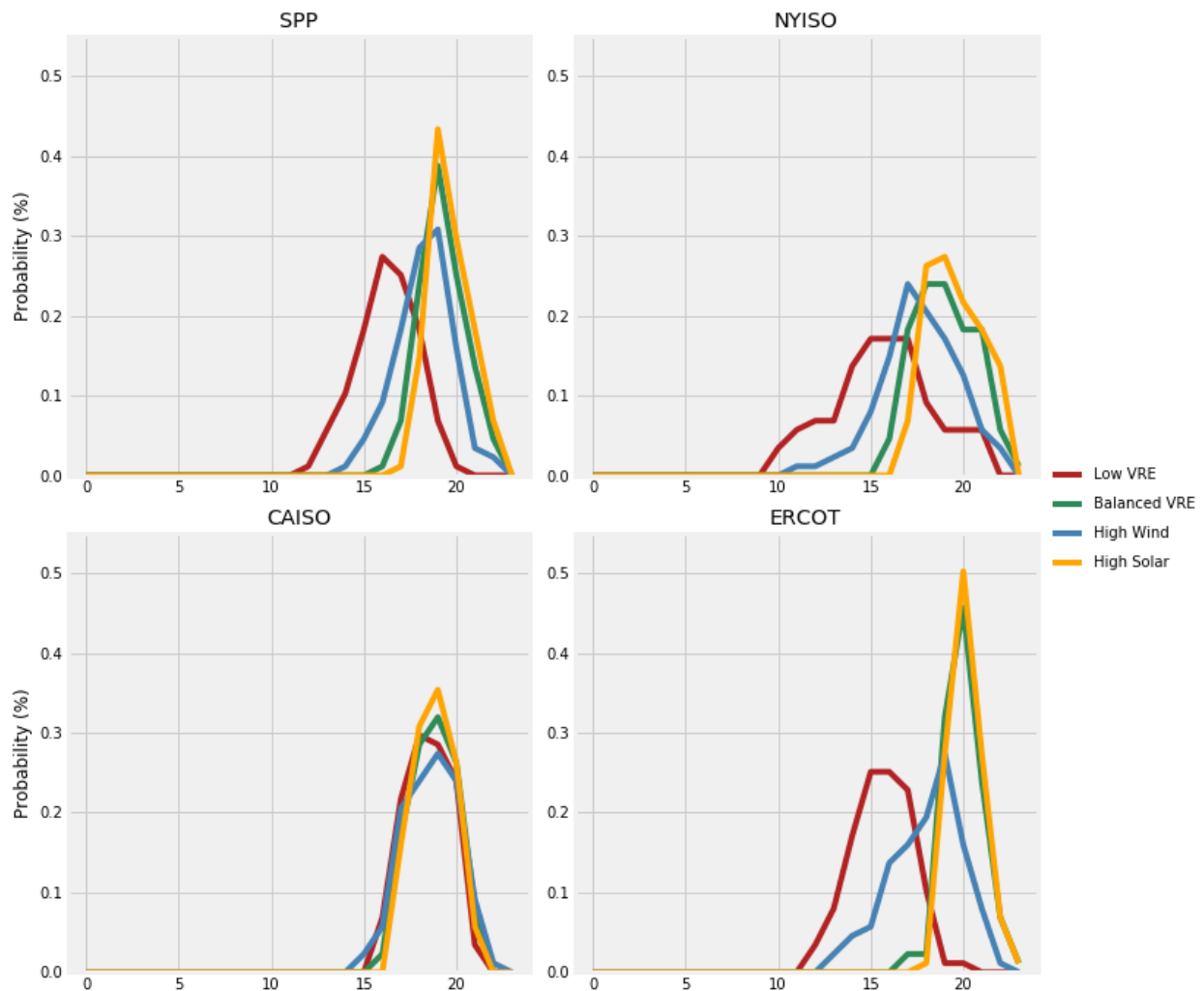
Figure 20 Probability that Hour is within the Highest 100 Net-Load Hours of the Year

Because peak net-load hours in the high VRE scenarios will occur over fewer hours in the early evening, yet over more days across the summer, revised demand-response programs could play a more important role in addressing system capacity requirements. In contrast, Critical Peak Pricing tariffs that have only few call-options per year may be less effective, unless these tariffs increase the number of calls available. The "skinny peaks" further emphasize the value of fast-ramping, flexible generators or storage units that can offer additional supply resources for a short period of time.

5.10 Differences in Energy Prices Between Balanced and Unbalanced Approaches

We structured our analysis to enable us to explore differences between long-run equilibrium market conditions (at least for the portfolio of traditional non-VRE generators) that allow for changes in

generator expansion or retirements due to the introduction of VRE (balanced portfolio approach) and conditions in which the base generator portfolio is maintained even with substantial growth in VRE (unbalanced portfolio approach). One aspect of our analysis that softens differences between these approaches is that the capacity expansion model already builds an efficient portfolio of generators for the base year 2030, leading to a substantial replacement of older inefficient units (that are presently still in the respective ISO markets) with more efficient natural gas units. Consequently, the marginal impacts of the VRE additions are relatively similar between our balanced and unbalanced portfolio approaches in most regions and scenarios. The primary difference worth highlighting is that in a market with a surplus of capacity, as in our unbalanced portfolio approaches, extreme price spikes become less frequent and have a lower absolute magnitude. In ERCOT, this leads to fewer ORDC-driven price spikes and a resulting decrease in load-weighted average prices. In the high solar and balanced VRE scenarios, the unbalanced portfolio approach results in prices that are about $5/MWh lower than in the balanced portfolio approach, presented earlier. ERCOT's coefficient of variability also decreases with the unbalanced portfolio approach to less than 1 in the balanced VRE scenario and to about 2 in the high solar scenario (one price outlier still remains at $4500/MWh). With the exception of these ERCOT cases we find little need to distinguish between the balanced and unbalanced portfolio approaches.

6. Discussion

We find that obtaining high shares of energy from variable energy resources leads to several profound changes in the characteristics of electric power systems.

The most fundamental changes relate to the timing of when electricity is cheap or expensive and the degree of regularity in those patterns. The frequency of periods with low prices (below $5/MWh) increases from zero hours in the low VRE scenarios to between 3% and 19% of hours in the high VRE scenarios depending on the region and mix of renewables. High solar in ERCOT, with its limited interconnection capacity to neighboring regions, experiences the highest frequency of periods with near zero prices. Common occurrences of periods with very low prices will affect the profitability of VRE and inflexible generators that operate in these hours, but also presents an opportunity to shift or increase demand at very low cost.

Across all of the regions, high solar scenarios lead to the largest change in the diurnal profile of prices and the greatest overall variation in prices. High wind scenarios, on the other hand, lead to the greatest increase in irregularity of pricing patterns. As a result, electricity suppliers or various electric-sector programs may need to be more flexible and adaptable in a high wind future than in a low VRE or even a high solar future.

High VRE scenarios enable some reduction in the capacity of thermal generation, yet energy from non-VRE generators decreases more significantly, particularly for natural gas and coal. Furthermore, average annual hourly energy prices decline in high VRE scenarios relative to low VRE. For many generators, this reduction in average energy prices will increase the relative importance of ancillary service and capacity

market products. In all regions we find that high VRE scenarios result in higher ancillary service prices, absent the ability of VRE to provide ancillary services or the entry of new emerging providers of ancillary services, such as batteries. Capacity prices on the other hand remain relatively steady. Nonetheless, the high VRE scenarios consistently spread peak net-load hours over more days of the year and push the timing of such hours into the early evening, indicating a potential shift in the resource portfolio that can contribute to meeting resource adequacy requirements.

It is crucial to note however, that the portrayed price changes will elicit responses by other market participants which in turn will affect prices. While the capacity expansion model that we used has optimized the non-VRE supply portfolio by selecting among traditional generator types, it has not considered investments into demand-side assets that would change the aggregate load profiles (certain energy efficiency measures or demand-response programs) or investments into electro-chemical battery storage. Very high energy prices during scarcity hours or sustained high ancillary service prices would likely motivate investments into these technologies, which subsequently would moderate prices again.

The price results are further a consequence of our modeling assumptions: The expansion of intra-regional transmission masks price variability related to local congestion, while the assumed high VRE penetrations in neighboring regions limit price mitigation due to exports and imports. Changes in our fuel price assumptions (e.g., natural gas relative to coal) would impact the merit order curve and could lead to a different optimal generator portfolio with different flexibility and ramping characteristics. Altered load profiles (such as mass deployment of electric vehicles with price-responsive charge management) would affect our diurnal price profiles. Differences in the absolute load level forecast that do not affect the load shape (e.g., due to better energy efficiency performance or less energy-intensive economic growth) would likely have less of an impact, as the generator portfolio would adjust with the retirement of some marginal plants. Because we have only considered a single exemplary year of 2030, inter-annual variation (that may include stronger cold-spells with high heating demands, droughts with less hydro-power availability, or heat waves with large additional cooling loads) and a further evolution of the electric system beyond 2030 are not captured by our analysis.

Despite these limitations, we find that electric systems with large shares of VRE penetration will see profound changes in average electricity prices, diurnal price patterns, and price volatility that should be considered in decisions related to long-lasting assets. This paper qualitatively highlighted some of the possible impacts on other demand- and supply-side decisions. While the decision-making processes and considerations may differ between regulated and de-regulated regions of the country, analysis of the marginal value of different resources can be informative in either case. As such, these simulated wholesale prices can provide a foundation for quantitative evaluations to explore how various demand- and supply-side decisions might be affected by changes in the future electricity supply mix.

7. References

ACEEE. (2016). *State and Local Policy Database*. American Council for an Energy-Efficient Economy. Retrieved from http://database.aceee.org/state/evaluation-measurement-verification

Alstone, P., Potter, J., Piette, M. A., Schwartz, P., Berger, M., Dunn, L., … Walter, T. (2016). *2015 California Demand Response Potential Study - Final Report on Phase 2 Results*. Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL). Retrieved from http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451541

Bajwa, M., & Cavicchi, J. (2017). Growing Evidence of Increased Frequency of Negative Electricity Prices in U.S. Wholesale Electricity Markets. *IAEE Energy Forum*, 37–41.

Bielen, D., Burtraw, D., Palmer, K., & Steinberg, D. (2017). *The Future of Power Markets in a Low Marginal Cost World* (No. RFF WP 17-26). Washington D.C.: Resources for the Future. Retrieved from http://www.rff.org/files/document/file/RFF%20WP%2017-26.pdf

Bistline, J. E. (2017). Economic and technical challenges of flexible operations under large-scale variable renewable deployment. *Energy Economics*, *64*, 363–372. https://doi.org/10.1016/j.eneco.2017.04.012

Bloom, A., Townsend, A., Palchak, D., Novacheck, J., King, J., Barrows, C., … Gruchalla, K. (2016). *Eastern Renewable Generation Integration Study*. Golden, CO: National Renewable Energy Laboratory.

Boomhower, J., & Davis, L. (2016). *Do Energy Efficiency Investments Deliver at the Right Time?* (E2e Working Paper Series). Berkeley, CA: University of California, Berkeley. Retrieved from http://e2e.haas.berkeley.edu/pdf/workingpapers/WP023.pdf

Brancucci Martinez-Anido, C., Brinkman, G., & Hodge, B.-M. (2016). The impact of wind power on electricity prices. *Renewable Energy*, *94*, 474–487. https://doi.org/10.1016/j.renene.2016.03.053

Brinkman, G., Jorgenson, J., Ehlen, A., & Caldwell, J. (2016). *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California* (No. NREL/TP-6A20-64884). Golden, CO: National Renewable Energy Laboratory (NREL). Retrieved from http://lowcarbongrid2030.org/

Clò, S., Cataldi, A., & Zoppoli, P. (2015). The merit-order effect in the Italian power market: The impact of solar and wind generation on national wholesale electricity prices. *Energy Policy*, *77*, 79–88. https://doi.org/10.1016/j.enpol.2014.11.038

Cludius, J., Hermann, H., Matthes, F. C., & Graichen, V. (2014). The Merit Order Effect of Wind and Photovoltaic Electricity Generation in Germany 2008-2016 Estimation and Distributional Implications. *Energy Economics*, *44*, 302–313. https://doi.org/10.1016/j.eneco.2014.04.020

CPUC. (2016). *CPUC CA RPS Calculator v.6.2*. San Francisco, CA: California Public Utilities Commission (CPUC). Retrieved from http://www.cpuc.ca.gov/RPS_Calculator/

Cutler, N. J., Boerema, N. D., MacGill, I. F., & Outhred, H. R. (2011). High penetration wind generation impacts on spot prices in the Australian national electricity market. *Energy Policy*, *39*(10), 5939–5949. https://doi.org/10.1016/j.enpol.2011.06.053

Deason, J., Wei, M., Leventis, G., Smith, S., & Schwartz, L. (2018). *Electrification of Buildings and Industry in the United States - Drivers, Barriers, Prospects, and Policy Approaches* (No. LBNL-2001133).

Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL). Retrieved from https://emp.lbl.gov/publications/electrification-buildings-and

Deetjen, T. A., Garrison, J. B., Rhodes, J. D., & Webber, M. E. (2016). Solar PV integration cost variation due to array orientation and geographic location in the Electric Reliability Council of Texas. *Applied Energy*, *180*, 607–616. https://doi.org/10.1016/j.apenergy.2016.08.012

Denholm, P., Novacheck, J., Jorgenson, J., & O'Connell, M. (2016). *Impact of Flexibility Options on Grid Economic Carrying Capacity of Solar and Wind: Three Case Studies*. Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy17osti/66854.pdf

Dennis, K. (2015). Environmentally Beneficial Electrification: Electricity as the End-Use Option. *The Electricity Journal*, *28*(9), 100–112. https://doi.org/10.1016/j.tej.2015.09.019

Dennis, K., Colburn, K., & Lazar, J. (2016). Environmentally beneficial electrification: The dawn of 'emissions efficiency.' *The Electricity Journal*, *29*(6), 52–58. https://doi.org/10.1016/j.tej.2016.07.007

DOE. (2017). *Staff Report to the Secretary on Electricity Markets and Reliability*. Washington D.C.: U.S. Department of Energy.

Ederer, N. (2015). The market value and impact of offshore wind on the electricity spot market: Evidence from Germany. *Applied Energy*, *154*, 805–814. https://doi.org/10.1016/j.apenergy.2015.05.033

Ela, E., Kirby, B., Navid, N., & Smith, C. (2012). Effective Ancillary Services Market Designs on High Wind Power Penetration Systems. Presented at the IEEE Power and Energy Society General Meeting, San Diego, CA: National Renewable Energy Laboratory (NREL). Retrieved from https://www.nrel.gov/docs/fy12osti/53514.pdf

Energy and Environmental Economics, Inc. (2014). *Investigating a Higher Renewables Portfolio Standard in California*. San Francisco, CA: Energy and Environmental Economics, Inc.

EnerNex Corporation. (2010). *Eastern Wind Integration and Transmission Study (EWITS)*. Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html

Fagan, B., Chang, M., Knight, P., Schultz, M., Comings, T., Hausman, E., & Wilson, R. (2012). *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Cambridge, MA: Synapse Energy Economics, Inc.

Felder, F. A. (2011). Examining Electricity Price Suppression Due to Renewable Resources and Other Grid Investments. *The Electricity Journal*, *24*(4), 34–46. https://doi.org/10.1016/j.tej.2011.04.001

Frew, B., Gallo, G., Brinkman, G., Milligan, M., Clark, K., & Bloom, A. (2016). *Impact of Market Behavior, Fleet Composition, and Ancillary Services on Revenue Sufficiency* (No. NREL/TP-5D00-66076). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy16osti/66076.pdf

GE Energy. (2010). *Western Wind and Solar Integration Study*. Golden, CO: National Renewable Energy Laboratory.

GE Energy. (2014). *PJM Renewable Integration Study*. Schenectady, NY: Prepared for PJM Interconnection, LLC.

Gil, H. A., & Lin, J. (2013). Wind Power and Electricity Prices at the PJM Market. *IEEE Transactions on Power Systems*, *28*(4), 3945–3953. https://doi.org/10.1109/TPWRS.2013.2260773

Gilmore, J., Rose, I., Vanderwaal, B., & Riesz, J. (2015). Integration of solar generation into electricity markets: an Australian National Electricity Market case study. *IET Renewable Power Generation*, *9*(1), 46–56. https://doi.org/10.1049/iet-rpg.2014.0108

Griddy. (2018, March). The cheapest Texas electricity rates are the real-time rates. Retrieved March 28, 2018, from https://www.gogriddy.com/electricity-rates/

Haas, R., Lettner, G., Auer, H., & Duic, N. (2013). The looming revolution: How photovoltaics will change electricity markets in Europe fundamentally. *Energy*, *57*, 38–43. https://doi.org/10.1016/j.energy.2013.04.034

Haratyk, G. (2017). Early nuclear retirements in deregulated U.S. markets: Causes, implications and policy options. *Energy Policy*, *110*, 150–166. https://doi.org/10.1016/j.enpol.2017.08.023

Hodge, B.-M. (2013a, September). Solar Power Data for Integration Studies. National Renewable Energy Laboratory (NREL). Retrieved from https://www.nrel.gov/grid/solar-power-data.html

Hodge, B.-M. (2013b, September). Wind Integration Data Sets. National Renewable Energy Laboratory (NREL). Retrieved from https://www.nrel.gov/grid/wind-integration-data.html

Hogan, W. W., & Pope, S. (2017). *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*. FTI Consulting.

Hummon, M., Denholm, P., Jorgenson, J., Palchak, D., Kirby, B., & Ma, O. (2013). *Fundamental Drivers of the Cost and Price of Operating Reserves*. Golden, CO: National Renewable Energy Laboratory.

Jenkins, J. D. (2017). What is Killing Nuclear Power in the American Midwest? Presented at the AERE Summer Meeting, Pittsburgh, PA.

Keay, M. (2016). *Electricity markets are broken- can they be fixed?* Oxford, UK: The Oxford Institute for Energy Studies.

Krauss, C., & Cardwell, D. (2015, November 8). A Texas Utility Offers a Nighttime Special: Free Electricity. *The New York Times*. Retrieved from https://www.nytimes.com/2015/11/09/business/energy-environment/a-texas-utility-offers-a-nighttime-special-free-electricity.html

Kyritsis, E., Andersson, J., & Serletis, A. (2017). Electricity prices, large-scale renewable integration, and policy implications. *Energy Policy*, *101*, 550–560. https://doi.org/10.1016/j.enpol.2016.11.014

Lazar, J. (2016). *Teaching the "Duck" to Fly - Second Edition*. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/document/download/id/7956

Lazar, J., & Colburn, K. (2013). *Recognizing the Full Value of Energy Efficiency*. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/wp-content/uploads/2016/05/rap-lazarcolburn-layercakepaper-2013-sept-9.pdf

LCG Consulting. (2016). *Market effects of wind penetration in ERCOT- How wind will change the future of energy and ancillary service prices*. Los Altos, CA. Retrieved from http://www.energyonline.com/Reports/Files/ERCOTWindPenetrationStudy_EXEC.SUMMARY.pdf

LCG Consulting. (2017a, August). Generator and Transmission Expansion Model (Gen X). Retrieved from http://www.energyonline.com/Products/GeneratorX.aspx

LCG Consulting. (2017b, August). UPLAN-ACE- A Daily Energy Model that Simulates Real-Time Dispatch at Intra-Hour Level. Retrieved from http://www.energyonline.com/Products/UplanACE.aspx

Levin, T., & Botterud, A. (2015). Electricity market design for generator revenue sufficiency with increased variable generation. *Energy Policy*, *87*, 392–406. https://doi.org/10.1016/j.enpol.2015.09.012

Lew, D., Brinkman, G., Ibanez, E., Florita, A., Heaney, M., Hodge, B.-M., … Lefton, S. A. (2013). *The Western Wind and Solar Integration Study Phase 2* (No. NREL/TP-5500-55588) (p. 244). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.osti.gov/scitech/servlets/purl/1095399

Maggio, D. J. (2012). Impacts of Wind-powered Generation Resource integration on prices in the ERCOT Nodal Market. In *2012 IEEE Power and Energy Society General Meeting* (pp. 1–4). https://doi.org/10.1109/PESGM.2012.6344611

Makovich, L., & Richards, J. (2017). *Ensuring Resilient and Efficient Electricity Generation: The Value of the Current Diverse US Power Supply Portfolio*. IHS Markit.

Mills, A., & Wiser, R. (2012). *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (No. LBNL-5933E). Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from emp.lbl.gov/sites/all/files/lbnl-5933e_0.pdf

Mills, A., & Wiser, R. (2013). Changes in the Economic Value of Photovoltaic Generation at High Penetration Levels: A Pilot Case Study of California. *IEEE Journal of Photovoltaics*, *3*(4), 1394–1402. https://doi.org/10.1109/JPHOTOV.2013.2263984

Mills, A., & Wiser, R. (2014). Changes in the Economic Value of Wind Energy and Flexible Resources at Increasing Penetration Levels in the Rocky Mountain Power Area. *Wind Energy*, *17*(11), 1711–1726. https://doi.org/10.1002/we.1663

Mims, N., Eckman, T., & Goldman, C. (2017). *Time-varying value of electric energy efficiency* (No. LBNL-2001033). Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL). Retrieved from https://emp.lbl.gov/publications/time-varying-value-electric-energy

Mims, N., Eckman, T., & Schwartz, L. (2018). *Time-Varying Value of Energy Efficiency in Michigan*. Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL). Retrieved from https://emp.lbl.gov/publications/time-varying-value-energy-efficiency/

Ming, Z., Clark, V., Price, S., Conlon, B., Staver, H., Horii, B., & Cutter, E. (2016). *Time Dependent Valuation of Energy for Developing Building Efficiency Standards - 2019 TDV Data Sources and Inputs* (No. 16- BSTD- 06). San Francisco, CA: Energy and Environmental Economics, Inc. Retrieved from http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212119_20160705T162207_Draft_2019_TDV_Methodolgy_Report.pdf

Morris, F. (2016, October 24). Waste, Families Left Behind As Nuclear Plants Close. Retrieved February 15, 2018, from https://www.npr.org/2016/10/24/498842677/waste-families-left-behind-as-nuclear-plants-close

Myers, J., & Skumatz, L. (2006). Evaluating Attribution, Causality, NEBs and Cost Effectiveness in Multifamily Programs- Enhanded Techniques (Vol. 2, pp. 216–228). Presented at the ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, California: ACEEE. Retrieved from http://aceee.org/files/proceedings/2006/data/papers/SS06_Panel2_Paper19.pdf

Neme, C., & Kushler, M. (2010). Is it Time to Ditch the TRC? Examining Concerns with Current Practice in Benefit-Cost Analysis. Presented at the 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, California. Retrieved from http://energy.maryland.gov/Documents/ACEEEreferencestudy-NemeandKushlerSS10_Panel5_Paper06.pdf

NESCOE. (2017). *Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study*. Retrieved from http://nescoe.com/resource-center/mechanisms-scenario-analysis-mar2017/

NYISO. (2010). *Growing Wind - Final Report of the NYISO 2010 Wind Generation Study*. Retrieved from https://www.nrc.gov/docs/ML1233/ML12339A588.pdf

Perez-Arriaga, I. J., & Batlle, C. (2012). Impacts of Intermittent Renewables on Electricity Generation System Operation. *Economics of Energy & Environmental Policy*, *1*(2). https://doi.org/10.5547/2160-5890.1.2.1

Sáenz de Miera, G., del Río González, P., & Vizcaíno, I. (2008). Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain. *Energy Policy*, *36*(9), 3345–3359. https://doi.org/10.1016/j.enpol.2008.04.022

Schlag, N., Olson, A., Hart, E., Mileva, A., Jone, R., Martinez-Anido, C. B., … Biagioni, D. (2015). *Western Interconnection Flexibility Assessment*. San Francisco, CA: Energy and Environmental Economics, Inc. (E3), National Renewable Energy Laboratory (NREL). Retrieved from https://www.wecc.biz/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf

Sensfuß, F., Ragwitz, M., & Genoese, M. (2008a). The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. *Energy Policy*, *36*(8), 3086–3094. https://doi.org/10.1016/j.enpol.2008.03.035

Sensfuß, F., Ragwitz, M., & Genoese, M. (2008b). The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. *Energy Policy*, *36*(8), 3086–3094. https://doi.org/10.1016/j.enpol.2008.03.035

Stern, F. (2013). *Peak Demand and Time-Differentiated Energy Savings Cross-Cutting Protocols* (No. NREL/SR-7A30-53827). Boulder, CO: National Renewable Energy Laboratory (NREL). Retrieved from http://energy.gov/sites/prod/files/2013/11/f5/53827-10.pdf

U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability. (2013). *OG&E Uses Time-Based Rate Program to Reduce Peak Demand*. Washington D.C. Retrieved from https://www.smartgrid.gov/files/OGE_CBS_case_study.pdf

U.S. Energy Information Administration (EIA). (2017). *California wholesale electricity prices are higher at the beginning and end of the day* (Today in Energy). Washington D.C. Retrieved from https://www.eia.gov/todayinenergy/detail.php?id=32172

U.S. Energy Information Administration (EIA). (2018). *Annual Energy Outlook 2018 with projections to 2050*. Washington D.C. Retrieved from https://www.eia.gov/outlooks/aeo/pdf/AEO2018_FINAL_PDF.pdf

Welisch, M., Ortner, A., & Resch, G. (2016). Assessment of RES technology market values and the merit-order effect – an econometric multi-country analysis. *Energy & Environment*, *27*(1), 105–121. https://doi.org/10.1177/0958305X16638574

Wiser, R., Barbose, G., Heeter, J., Mai, T., Bird, L., Bolinger, M., … Millstein, D. (2016). *A Retrospective Analysis of the Benefits and Impacts of US Renewable Portfolio Standards*. Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory.

Wiser, R., Mills, A., Seel, J., Levin, T., & Butterud, A. (2017). *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing, and Costs* (No. LBNL-2001082). Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL). Retrieved from https://emp.lbl.gov/publications/impacts-variable-renewable-energy

Woo, C. K., Ho, T., Zarnikau, J., Olson, A., Jones, R., Chait, M., … Wang, J. (2014). Electricity-market price and nuclear power plant shutdown: Evidence from California. *Energy Policy*, *73*, 234–244. https://doi.org/10.1016/j.enpol.2014.05.027

Woo, C. K., Horowitz, I., Moore, J., & Pacheco, A. (2011). The impact of wind generation on the electricity spot-market price level and variance: The Texas experience. *Energy Policy*, *39*(7), 3939–3944. https://doi.org/10.1016/j.enpol.2011.03.084

Woo, C. K., Horowitz, I., Zarnikau, J., Moore, J., Schneiderman, B., Ho, T., & Leung, E. (2016). What Moves the Ex Post Variable Profit of Natural-Gas-Fired Generation in California? *The Energy Journal*, *37*(3). https://doi.org/10.5547/01956574.37.3.cwoo

Woo, C. K., Moore, J., Schneiderman, B., Ho, T., Olson, A., Alagappan, L., … Zarnikau, J. (2016). Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets. *Energy Policy*, *92*, 299–312. https://doi.org/10.1016/j.enpol.2016.02.023

Woo, C. K., Zarnikau, J., Kadish, J., Horowitz, I., Wang, J., & Olson, A. (2013). The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest. *IEEE Transactions on Power Systems*, *28*(4), 4245–4253. https://doi.org/10.1109/TPWRS.2013.2265238

Woolf, T., Neme, C., Kushler, M., Schiller, S., & Eckman, T. (2017). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*. National Efficiency Screening Project (NESP). Retrieved from https://nationalefficiencyscreening.org/national-standard-practice-manual/

Würzburg, K., Labandeira, X., & Linares, P. (2013). Renewable Generation and Electricity Prices: Taking Stock and New Evidence for Germany and Austria. *Energy Economics*, *40*, *Supplement 1*, S159–S171. https://doi.org/10.1016/j.eneco.2013.09.011

Appendix A. Modeling Assumptions

Note: The raw model output of hourly energy and ancillary service prices, annual capacity prices, and information about the selected generator portfolios is publicly available on our publication website:
https://emp.lbl.gov/publications/impacts-high-variable-renewable

Capital, O&M, Fuel and Emission Cost Assumptions

Unit Type	Overnight Capital Cost ($/kW)	Annualized Capital Cost ($/kW-yr)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)
Gas – Advanced CC	$1,017	$65	$15.36	$3.27
Gas – Advanced CT	$671	$45	$7.04	$10.37

Table A - 1. Capital and O&M Costs by Unit Type considered by Capacity Expansion Model[25]

Fuel Type	SPP	NYISO	CAISO	ERCOT
Natural Gas[26]	$3.25	$3.79	$4.69	$3.33
Coal[27]	$2.76	$3.14	NA	$2.31
Uranium	$0.62	$0.62	$0.81	$0.50
Oil[28]	$11.20	$19.94	NA	NA

Table A - 2. Fuel Cost Assumptions by Region ($/million Btu)

Emission Type	SPP	NYISO[29]	CAISO[30]	ERCOT[31]
CO2	Not Used	$24.14	$52.56 (imports: $20/MWh)	Not Used
SOx	Not Used	$5/ton	Not Used	$10
NOx	Not Used	$217.5 (May-Sep) $15 (other months)	Not Used	$300 (May – Sep) $100 (other months)

Table A - 3. Emission Cost Assumptions by Region ($/ metric ton)

---

[25] Based on EIA – Annual Energy Outlook 2015, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies, Table 8.2 https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2015).pdf

[26] Based on CME Group (NYMEX) - http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html and Gas Daily - S&P Global Platts

[27] Based on EIA – Annual Energy Outlook 2017, Coal Minemouth Prices by Region and Type, Reference Case

[28] Based on New York Independent System Operator (2016), 'Congestion Assessment and Resource Integration Study, 2016 CARIS 2 Base Case Fuel and Emission Prices' http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp

[29] Based on New York Independent System Operator (2016), 'Congestion Assessment and Resource Integration Study, 2016 CARIS 2 Base Case Fuel and Emission Prices', http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp

[30] Based on California Energy Commission (December 2016), 'Preliminary GHG Price Projections', Mid-Consumption Scenario for 2030, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-03/TN216271_20170227T161611_Preliminary_GHG_Price_Projections__Energy_Assessment_Division.xlsx

[31] Based on 2016 Long Term System Assessment (LTSA) Current Trends Economic Case Input https://mis.ercot.com/misdownload/servlets/mirDownload?mimic_duns=1482219898000&doclookupId=550628414

Region	Unit Type	Fixed O&M Cost ($/kW-mon)	Variable O&M Cost ($/MWh)
SPP	Gas - CC	Average: 1.14 10th-90th Percentile Range: 0.18	Average: 3.53 10th-90th Percentile Range: 0.33
	Gas - CT	Average: 0.60	Average: 12.73 10th-90th Percentile Range: 5.08
	Coal	Average: 3.15	Average: 4.47
	Nuclear	Average: 7.77	Average: 2.14
	Oil	Average: 1.50 10th-90th Percentile Range: 2.47	Average: 2.23 10th-90th Percentile Range: 2.12
	Other Renewables	Average: 1.44 10th-90th Percentile Range: 0.32	Average: 0.10
NYISO	Gas - CC	Average: 1.11 10th-90th Percentile Range: 0.18	Average: 3.92 10th-90th Percentile Range: 0.33
	Gas - CT	Average: 0.8 10th-90th Percentile Range: 0.79	Average: 11.04 10th-90th Percentile Range: 5.08
	Nuclear	8.18	Average: 2.75 10th-90th Percentile Range: 1.02
	Oil	Average: 1.60 10th-90th Percentile Range: 1.03	Average: 2.56 10th-90th Percentile Range: 3.31
	Other Renewables	Average: 1.30 10th-90th Percentile Range: 0.33	Average: 0.16
CAISO	Gas - CC	Average: 0.98 10th-90th Percentile Range: 0.41	Average: 1.15 10th-90th Percentile Range: 1.40
	Gas - CT	Average: 0.71 10th-90th Percentile Range: 0.86	Average: 1.35 10th-90th Percentile Range: 1.91
	Nuclear	Average 8.2	Average: 5.3 10th-90th Percentile Range: 5.3
	Other Renewables	Average: 3.10 10th-90th Percentile Range: 8.44	0.67 90th-10th Percentile Range: 5
ERCOT	Gas - CC	Average: 1.24 10th-90th Percentile Range: 0.72	Average: 3.72
	Gas - CT	Average: 0.76 10th-90th Percentile Range: 0.53	Average: 13.07 10th-90th Percentile Range: 5.08
	Coal	Average: 3.15	Average: 4.47
	Nuclear	Average: 7.77	Average: 2.14
	Other Renewables	Average: 1.18	

Table A - 4. Fixed and Variable O&M Costs for Existing Units by Unit Type and Region

Ancillary Service Requirement Assumptions by Region

Scenario	Regulation-Up	Regulation-Down	Spin	Non-Spin
Low VRE	470	325	585	730
Balanced VRE	638	493	585	730
High Wind	619	474	585	730
High Solar	687	541	585	730

Table A - 5. Annual Average Ancillary Service Requirements in MW for SPP[32]

Scenario	Regulation	10min Spin	30min Reserves
Low VRE	217	655	2620
Balanced VRE	332	655	2620
High Wind	330	655	2620
High Solar	337	655	2620

Table A - 6. Annual Average Ancillary Service Requirements in MW for NYISO[33]

Scenario	Regulation-Up	Regulation-Down	Spin	Non-Spin
Low VRE	442	448	860	860
Balanced VRE	597	582	860	860
High Wind	577	564	860	860
High Solar	595	580	860	860

Table A - 7. Annual Average Ancillary Service Requirements in MW for CAISO[34]

Scenario	Regulation-Up	Regulation-Down	Spin	Non-Spin
Low VRE	318	295	1308	1533
Balanced VRE	430	383	1308	1533
High Wind	415	372	1308	1533
High Solar	428	382	1308	1533

Table A - 8. Annual Average Ancillary Service Requirements in MW for ERCOT[35]

---

[32] For Low VRE scenario: 2016 hourly requirements (ftp://pubftp.spp.org/Markets/DA/MARKET_CLEARING/2016).
For High VRE scenarios: 1.2% increase in reserve with every MW increase in wind capacity, based on hourly VRE generation (Charles River Associates. 2010. "SPP WITF Wind Integration Study." Little Rock, AR: Southwest Power Pool)
[33] For Low VRE scenario:
http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_regulation_req.pdf
For High VRE scenarios: The maximum increase in the regulation requirement is estimated using a VRE-regulation curve derived from the NYISO Solar Integration Study 2016 and extended for higher VRE levels. The hourly requirement is then adjusted based on the hourly VRE generation.
[34] For Low VRE scenario: Historical requirements are considered as the base and scaled based on the load forecast.
For High VRE scenarios: The maximum increase in the regulation requirement is estimated using a VRE-regulation curve derived from CAISO (2010) "Integration of Renewable Resources at 20% RPS."
http://www.caiso.com/2804/2804d036401f0.pdf. The hourly requirement is then adjusted based on the hourly VRE generation.
[35]For Low VRE scenario: Projected Ancillary Service Requirements, published June, 2017
https://mis.ercot.com/misapp/GetReports.do?reportTypeId=13020&mimic_duns=1482219898000 .
For High VRE scenarios: Incremental MW adjustments per 1000 MW of incremental renewable generation capacity for both Reg-Up and Reg-Down were based on "ERCOT Methodologies for Determining Minimum Ancillary Service Requirements".

Capacity Credit Assumptions for Wind and Solar

	Scenario	SPP	NYISO	CAISO	ERCOT
Existing Units	Low VRE	10.0%	15.0%	12.0%	14 % Non-Coastal; 58% Coastal
New Units	Balanced VRE	23.0%	21.8%	13.0%	19.0%
	High Wind	24.0%	19.8%	10.0%	20.0%
	High Solar	No New Wind	23.5%	16.0%	No New Wind

Table A - 9. Average Wind Capacity Credits for Existing and New Projects in Planning Reserve Margin Calculations

	Scenario	SPP	NYISO	CAISO	ERCOT
Existing Units	Low VRE	80%	30%	41%	77%
New Units	Balanced VRE	12%	14%	9%	33%
	High Wind	20%	23%	No New Solar	63%
	High Solar	8%	9%	8%	21%

Table A - 10. Average Solar Capacity Credits for Existing and New Projects in Planning Reserve Margin Calculations