EXHIBIT

Exhibit No.:	____________
Issue(s)	Response to the Conditions Staff Recommends In Its Rebuttal Report
Witness/Type of Exhibit:	Mantle/Surrebuttal
Sponsoring Party:	Public Counsel
Case No.:	EA-2019-0010

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EA-2019-0010

** **

Denotes Highly Confidential Information that has been Redacted

February 5, 2019

OPC Exhibit No. 206-P
Date 4-8-19 Reporter TT
File No. EA-2019-0010

PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Certificates of Convenience and Necessity Related to Wind Generation Facilities	))))	File No. EA-2019-0010

AFFIDAVIT OF LENA MANTLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Lena Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M. Mantle
Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 5th day of March 2019.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
JERENE A. BUCKMAN
My Commission Expires
August 23, 2021
Cole County
Commission #13754037

Jerene A. Buckman
Jerene A. Buckman
Notary Public

My Commission expires August 23, 2021.

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SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE, P.E.

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EA-2019-0010

Q. What is your name?

A. Lena M. Mantle.

Q. Are you the same Lena M. Mantle who testified in rebuttal in this case?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. I respond to the conditions Staff recommends in its rebuttal report it believes would result in the Kings Point, North Ford Ridge, and Neosho Ridge wind farm projects meeting its interpretation of whether there is a "need" for the projects as required to grant the certificates of convenience and necessity ("CCNs") the Empire District Electric Company ("Empire") is requesting.

Need

Q. How does Staff interpret "need" for purposes of the Commission issuing Empire CCNs for these wind farm projects?

A. Staff provides its interpretation in its Rebuttal Report as follows:

> In the context of the Tartan Criteria, Staff has interpreted "need" as a requirement for the applicant to demonstrate that there are benefits to the project which justify its cost.[1]

Q. Using Staff's interpretation of "need," in your opinion do the conditions Staff is proposing in its Rebuttal Report cause any of the wind projects to have benefits justifying the cost of the project?

[1] Staff Rebuttal Report, page 15, lines 20 – 21.

A. Staff's interpretation is tied to economic feasibility of the projects. Staff's conditions do not reduce the uncertainty regarding the costs of the projects, revenues to be received due to the projects, the amount of generation of the projects, or the financing of the projects. Staff's conditions just reduce the amount of economic harm to Empire's captive ratepayers. There is a good likelihood that even with the conditions Staff proposes, these projects would not economically benefit Empire's customers. The Office of the Public Counsel's ("OPC") recommendation that Empire's captive customers be held harmless, not just less harmed, remains unchanged from when it filed its rebuttal testimony.

Q. What is OPC's recommendation in this case?

A. If the Commission grants Empire any of the CCNs, OPC recommends that the Commission condition each CCN on Empire making its customers whole through rates for each year during the life of the wind farms. In other words, when the wind farms do not generate net cash through the Holdcos equal to or greater than the costs of the wind farm included in rates, customers would be held harmless. This condition includes all costs, including but not limited to the return of and on the capital investment for these wind farms, all operations and maintenance costs, and administrative and general costs allocated to the wind farms when the Commission determines Empire's cost of service for setting rates.

Including this condition in any CCN is imperative to protect Empire's customers, because the potential for the "savings" Empire touts not materializing is so significant that without this condition the harmful impact on Empire's customers and the whole Southwest Missouri region could be substantial.

Q. Are the Kings Point, North Ford Ridge, and Neosho Ridge wind projects for which Empire is requesting CCNs needed?

A. The answer depends on how one defines need. Empire does not need them to meet its customers' current electrical capacity or energy requirements. Empire's 2016 preferred resource plan showed that no additional resources were necessary for it to meet its customers' load requirements until 2029.

Q. Are changes in Empire customers' load requirements since the filing of its 2016 Resource Plan driving the addition of this wind generation?

A. No. In Empire's forecast used to determine its 2016 preferred resource plan, Empire forecasted that it would continue to supply energy to its four municipal customers through 2035.[2] However, Empire customers' load requirement will be dropping considerably in 2020. Starting in late 2017, after Empire filed its 2016 preferred resource plan, the municipal utilities of the cities of Monett and Mt. Vernon, Missouri, and Chetopa, Kansas, announced they would not renew their contracts with Empire that end in the summer of 2020. Empire's 2017 Annual Report[3] submitted to the Commission shows that these three customers purchased an aggregate of 315,008 megawatt-hours ("MWh") from Empire in 2017. That usage is approximately 6% of the total usage Empire billed its retail customers in 2017. The loss of these three wholesale customers delays the need for Empire to add generation to meet its remaining customers' load requirements even further into the future.

Therefore, Empire does not need any of these three wind projects to meet its customers' current load requirements or what Empire is forecasting their load requirements to be over the next ten to twelve years. No party in this case is asserting that any of these wind projects is necessary for Empire to meet its customers' current or projected load requirements. These are speculative wind projects, i.e., Empire is speculating that these projects, based on thirty-year

[2] EO-2016-0233, Load Analysis and Load Forecasting, Volume 3, page 3 – 84, filed April 1, 2016.
[3] BARE-2018-1695, Annual Report (MO PSC) for 2017, Page 304.2, submitted May 10, 2018.

forecasts of costs, MWh of generation, and market prices, will provide net economic benefits over the next thirty years.

Q. Is it Staff's position that the Kings Point, North Ford Ridge, and Neosho Ridge wind farm projects are needed?

A. Using its interpretation of need to be "that there are benefits to the project which justify its cost," Staff states that the wind projects meet its interpretation of need *if* the Commission imposes a number of conditions that Staff recommends.

Q. Did Staff provide insight into why it recommends economic and operational conditions?

A. In its report Staff found that "there is a *reasonable likelihood* that Empire's proposed Wind Projects *can potentially result* in a net benefit to customers over the lives of the asset"[4] and provides that there is an "*inherent uncertainty* of relying upon long-range forecasts to justify the economic feasibility of these projects."[5] Staff also states that "While net benefits *are expected* for customers *based upon* the modeling conducted as part of Case No. EO-2018-0092, the benefits are heavily dependent on market prices and wind production values."[6] Staff claims there may be potential benefits based on Empire's projections, but those projections are inherently uncertain. These statements demonstrate Staff's uncertainty regarding the credibility of the information and analysis Empire provided to it to support these projects and its recognition of the amount of risk that would be placed on Empire's customers if the Commission approves the applications as filed.

[4] Id., page 29, lines 1 – 3 (emphasis added).
[5] Id., lines 3 – 4 (emphasis added).
[6] Id., page 5 lines 1 – 2 (emphasis added).

Staff further recognizes that Empire did not model the customer savings in this case[7] and, as a result of its review of Empire's filings and evidence, cautions the Commission to not rely on "certain" evidence put forth by Empire regarding costs and revenues in the Commission's findings of fact regarding need.[8] Staff then recommends conditions that would *reduce* the potential detriment to Empire's customers in the first ten years of the life of the projects to the point where Staff believes the benefits justify the costs.[9]

Q. Which conditions is Staff proposing for "need," i.e., with benefits justifying costs?

A. All of the conditions listed on page 37 of the Staff Rebuttal Report impact costs. However, Staff's recommendations regarding the Market Protection Provision are the conditions that Staff ties to its conclusion that, with these conditions, the benefits justify the costs.

<u>Market Protection Provision</u>

Q. What is the Market Protection Provision?

A. Some of the parties in Case No. EO-2018-0092 reached an agreement which OPC opposed that included what they described as a Market Protection Provision ("MPP"). They described the MPP as a "mechanism [that] seeks to provide for the sharing of risk between customers and shareholders associated with the possibility of reduced market prices and wind production."[10]

Q. How does the MPP work?

A. I am not sure, but, based on my review of the MPP language in Case No. EO-2019-0092, I can relate my understanding of it. OPC was not included in the

[7] Id., page 20, line 17.
[8] Id., page 21, lines 6 – 8; page 37, lines 2 – 5.
[9] Id., page 5, lines 5 – 6.
[10] Case No. EO-2018-0092, Non-Unanimous Stipulation and Agreement, page 8.

development of the MPP and Staff does not explain the MPP or provide the MPP language in its Rebuttal Report. The MPP is a complicated mechanism. My understanding is that the total costs to the customers of the wind projects and the Southwest Power Pool ("SPP") revenues from the energy generated by the wind farms would be aggregated separately every year. If the annual revenues from SPP for energy generated by the wind projects are greater than the annual costs of the wind projects, then the net benefit would be placed in a regulatory liability account. If the annual revenues are less than the annual costs, then the first $2 million of the net detriment and, to the extent the net detriment exceeds $2 million, one-half of the remaining detriment would be placed in a regulatory asset account. Shareholders would bear the other half, up to a cumulative amount of $35 million, i.e., shareholders would not bear more than $35 million of the deficit in the first ten years under the 50/50 sharing. Once the $35 million cap was reached for Empire, all of the deficit would be placed in the regulatory asset account.

At the time of each rate case in the first ten years, the cumulative annual wind projects benefits and losses would be aggregated and netted for creating a regulatory asset or liability that would be included in Empire's revenue requirement. An adjustment would be made to Empire's Missouri revenue requirement in the first rate case after the end of the tenth year for the amount of the regulatory asset or liability on Empire's books at that time.

Q. What is your opinion of the MPP proposed in Case No. EO-2018-0092?

A. If Empire really believed its analysis, customers should not have to assume the first $2 million of losses, and there would be no cap on the potential losses to shareholders. The fact that customers first had to assume some losses and that there was a cap on the impact to shareholders signifies that Empire had doubts about its own projections, even during the pendency of Case No. EO-2018-0092.

There is no reason why Empire's customers should be exposed to downside risk from these wind projects, when Empire is unwilling to expose its shareholders to that same risk. There is no good reason why Empire's customers should absorb all of the first $2 million of losses in each year and then all the losses after a cap $35 million has been met for the shareholders. Empire's customers would not see any additional benefit from these losses. They would already be paying all the costs of the wind projects. This provision would require them to take on more costs but not get receive anything in return. In the meantime, Empire's customers would provide Empire a return on and of its investment in the wind projects, and also a return on and of its tax equity partners' investment.

Finally, in the agreement, the shareholders were willing to take on $35 million of risk for the customers to pay for an investment of $600 million and to also pay a return on that $600 million. There was no cap on the amount that the customers would be asked to pay if market prices fell below the forecast, the wind projects did not achieve their forecasted generation, or costs of the wind projects skyrocket.

<u>Staff's Proposed Market Protection Provision</u>

Q. Is Staff recommending that the Commission condition Empire's CCNs on the MPP?

A. Yes, with modifications. Staff recommends the following changes to the MPP:

1) Removal of the cap of the losses that the shareholders would absorb;

2) A limit on the value of the PPA_Replacement amount included in the MPP;

3) Incorporation of yet-to-be identified, mutually agreed to, provisions that balance risks related to Transmission Congestion Rights ("TCRs") and Auction

Revenue Rights ("ARRs") related to the Neosho Ridge interconnection point to Empire's load serving area; and

4) Inclusion of network interconnection costs in the revenue requirement for each project.[11]

Q. What is your opinion with regard to Staff's proposed modified MPP?

A. It is my opinion that even with the modifications Staff recommends, the modified MPP still would not protect Empire's captive customers from harm. The customers should be held harmless. While the Staff-modified MPP is an improvement, it still would expose Empire's customers to harm, and the risk of more harm than that to which shareholders would be exposed.

Q. Why should Empire's customers be held harmless?

A. Empire can meet its customers' load requirements without these wind projects. They are speculative projects that Empire seeks to have its customers finance. Empire projects the revenues from SPP for the generation from the wind projects will be greater, over thirty years, than the costs, yet Empire wants *customers* to assume losses if Empire's projections of market prices, energy generation projections, or the costs estimates made by Empire were wrong. If Empire trusts its projections, its shareholders should be willing to assume the risk.

The unprecedented addition of renewable resources, not just by Empire but by many independent power producers and utilities in the SPP and other regional transmission operator ("RTO") markets across the nation, is creating new challenges for the markets, impacting the costs and potential benefits of these projects. Information I reviewed leads me to believe that Empire's projections could be drastically wrong, and not wrong in a manner that would benefit the Empire's customers.

[11] Staff Rebuttal Report, page 37.

Lawrence Berkeley National Laboratory's ("LBNL") May 2018, publication *Impacts of High Variable Renewable Energy Future on Wholesale Electric Prices, and on Electric-Sector Decision Making*[12] provides the results of LBNL's research on the impact of variable renewable energy ("VRE") resources, i.e. wind and solar, on wholesale market prices. LBNL's research shows annual average energy prices decline with increasing wind and solar resources. In particular, its research shows that annual market prices decline between \$0.1/MWh to \$0.9/MWh for each additional percentage of VRE penetration in a RTO market. I have attached this report to my testimony as Schedule LMM-S-1.

Additionally, I have attached as Schedule LMM-S-2 the MIT Center for Energy and Environmental Policy Research ("MIT CEEPR") January 2019, publication *Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience*[13] report. In this report MIT CEEPR describes the changes it sees as necessary as the United States moves from traditional dispatchable resources to greater penetration of intermittent VRE resources. One of the conclusions reached in this report follows:

> Very simply, as the penetration of intermittent generation with zero marginal costs grows to become a large fraction of total generation, market-based energy prices during the hours it operates will fall toward zero --- perhaps to zero in many hours if very aggressive wind and solar penetration goals are met.

If one is to believe these predictions by LBNL and MIT, SPP market prices will decline as more and more wind generation is added. This stands in stark contrast to the upward projections of market prices Empire forecasted in its analysis of these projects.

If Empire is wrong, and LBNL and MIT are correct, then Empire's customers would not only be on the hook for the cost of building these wind

[12] https://emp.lbl.gov/publications/impacts-high-variable-renewable
[13] Attached as LMM-S-2

projects, but they would not see the benefits touted by Empire and relied upon by Staff to conclude the benefits of these projects justify the costs. Empire's analysis already shows the net present value of the projects to be ** ** If the market price flattens or decreases as projected by LBNL and MIT, the impact on Empire's customers, even if they only absorb half of the losses in the first ten years as Staff recommends, would be tremendous. And all on wind projects that were not needed to meet the customers' load requirements.

Q. The LBNL and MIT research ties reductions in market prices to the penetration of wind. Do you have an estimate of the amount of wind that will be added in SPP?

A. According to SPP's *SPP 101: An Introduction to Southwest Power Pool* uploaded to SPP's website on February 5, 2019,[14] there currently is approximately 22 gigawatts ("GW"), i.e. 22,000 megawatts ("MW"), of wind online and approximately 10 GW of wind with signed interconnection agreements. This power point presentation shows that SPP estimates that there will be more than an additional 23 GW of wind installed in 2020 and that there are over 84 GW of pending generation interconnection requests of which over 54 GW is for future wind resources. SPP's highest peak load was just 51 GW.

Q. What does this mean if LNBL and MIT are correct?

A. If LNBL and MIT projections prove to be correct, SPP market prices will be declining in the near future, and, consequentially, Empire's proposed wind projects will not achieve the revenues promised.

[14] https://www.spp.org/documents/31587/intro%20to%20spp.pdf

Q. Staff's second modification to the MPP is to limit the value of the PPA_Replacement amount included in the MPP. Would you provide your understanding of what this is?

A. From what I read in the Non-Unanimous Stipulation and Agreement from Case No. EO-2018-0092, additional "value" would be attributed to customers when the current wind purchase power agreement contracts end. Empire currently uses a portion of the generation from these purchased power agreements to meet the Missouri Renewable Energy Standard ("RES") requirements. I do not know how the signatories to the MPP calculated the value they included in the MPP in Case No. EO-2018-0092.

Q. Do you agree with Staff's second modification to the MPP?

A. No. There should not be a PPA Replacement value in the MPP because this will not likely be the most cost effective way for Empire to comply with the Missouri RES requirements.

Q. Would you explain?

A. The Missouri RES requirements can be met with Renewable Energy Credits ("RECs") which represent the renewable attribute of a MWh of energy generated with a renewable fuel source. A generator can bank RECs for up to three years after the energy is generated. In other words, a REC for a MWh generated on January 1, 2025, can be used or "retired" any time from January 2, 2025, through January 1, 2028. Each MWh generated by a renewable resource creates a REC.

As shown in Staff's report,[15] Empire's current wind purchased power agreements generate more MWh than what the Missouri RES requires for Empire. To be wise stewards of this generation and the associated RECs, Empire should

[15] Page 17, Figure 1: Existing and Proposed REC production.

bank as many RECs from these contracts as necessary[16] to meet the Missouri RES for up to three years after the end of each of these contracts; thereby removing the need for Missouri retail customers to pay higher rates for Empire to meet the Missouri RES.

In addition to banking RECs, **

**

If Empire is not able to bank enough RECs through its current purchased power agreements and its own generating resources to meet the Missouri RES requirements before it completely owns all the wind farms in 2031, then it does have the alternative to purchase RECs at market value to meet the requirements. If even a fraction of the proposed SPP wind additions actually come to fruition, there will be an abundance of wind generation added in the next two years. This in turn will result in a glut of inexpensive wind RECs available for purchase. It would be imprudent to determine at this point in time exactly how Empire will meet its Missouri RES requirements and the cost of that compliance when there is so much renewable resource development projected to occur.

Q. What is the current price of a wind REC?

A. Currently the cost of a REC is less than $1.

Q. What happens if the PPA Replacement value is removed from the MPP?

A. The PPA replacement value increases the "benefit" of the project in years six through ten. The cost of the wind projects are netted against both the SPP revenues and this PPA replacement value to determine whether there is a net liability or asset in each year in years six through ten. Removing the PPA

[16] RECs created in excess of what is necessary to meet the Missouri RES should be sold with revenues

replacement value results in a greater likelihood of the costs being greater than the benefits in years six through ten. It also results in a greater likelihood of shareholders having to take on more of the risks in years six through ten.

Q. What is your opinion regarding Staff's third proposed modification to incorporate yet-to-be identified, mutually agreed-upon provisions that balance risks related to Transmission Congestion Rights ("TCRs") and Auction Revenue Rights ("ARRs") related to the Neosho Ridge interconnection point to Empire's load serving area?

A. Increases in TCRs and ARRs that may arise related to the Neosho Ridge interconnection point are a concern. However, it is hard to know how to respond to a yet-to-be identified provision and to state that I agree with it. For this reason, I do not have an opinion with respect to this modification.

Q. Staff's fourth modification is to include network interconnection costs in Empire's revenue requirement for each project. Summarily, why is Staff concerned about network interconnection costs?

A. There is potential for transmission congestion with the addition of each of these wind projects. Empire includes an estimate of network interconnection costs in its analysis of the wind projects. However, SPP's estimates of the interconnection costs for the projects are not known at this time, and likely will not be known until well after the Commission decides this case. Empire stated in its response to OPC data request 2063:

> The first round of modeling has not been completed by SPP. Based on a schedule available from SPP, that modeling is expected to be completed on October 20, 2019.

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returning to the customers through the fuel adjustment clause.

Subsequently, in response to OPC data request 2062, which requested an update on the status of Empire's Interim Generator Interconnection agreements for the three wind projects, Empire provided on March 2, 2019, the following:

> The interim availability studies requested for the three projects have not yet commenced due to SPP resource constraints. SPP has not been able to provide a definitive completion date for these studies.

Q. What is Staff's position with respect to these unknown interconnection costs?

A. Unless otherwise restricted by the Commission, these interconnections costs would be a pass through of cost to Empire's captive customers. It is Staff's recommendation that either the Commission order these unknown costs to be included in the MPP or "the Commission condition the CCN on an Empire commitment to cap the total network upgrade costs for which recovery may be sought at Empire's estimate plus a 10% contingency."[17]

Q. What is your opinion regarding Staff's recommendation?

A. In order to hold the customer harmless, I recommend the Commission, if it approves any of the CCNs, cap this cost at the lesser of the actual cost or Empire's estimate in the analysis Empire provided to support its requests for CCNs in this case. If the Commission orders Staff's proposed MPP, these costs should be included in the MPP at the lesser of the actual cost or Empire's estimate in the analysis Empire provided to support its requests for CCNs in this case. No amount above this cap should be collected from Empire's customers.

[17] Staff Rebuttal Report, page 34, lines 1 – 3.

Conclusion

Q. Would you summarize your testimony?

A. Empire does not need any of these three wind projects to meet its customers' current load requirements or what Empire is forecasting their load requirements to be over the next ten to twelve years. No party in this case is asserting that any of these wind projects is necessary for Empire to meet its customers' current or projected load requirements. These are speculative wind projects, i.e., Empire is speculating that these projects will, based on thirty-year forecasts of costs, MWh of generation, and market prices provide net economic benefits over the next thirty years.

Because these are speculative projects, the Commission should, if it grants Empire a CCN for any of these projects, require Empire to hold customers harmless each year throughout the life of the project. The conditions proposed by Staff, while reducing the potential amount of harm that could be passed on to Empire's customers, does not assure that those customers would be held harmless.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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

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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

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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

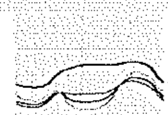
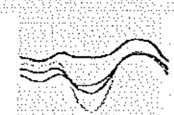
Executive Summary

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%	-17%	-18%	-19%	-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 qualitatively 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 quantitative 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 qualitatively 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 quantitative 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.

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[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).

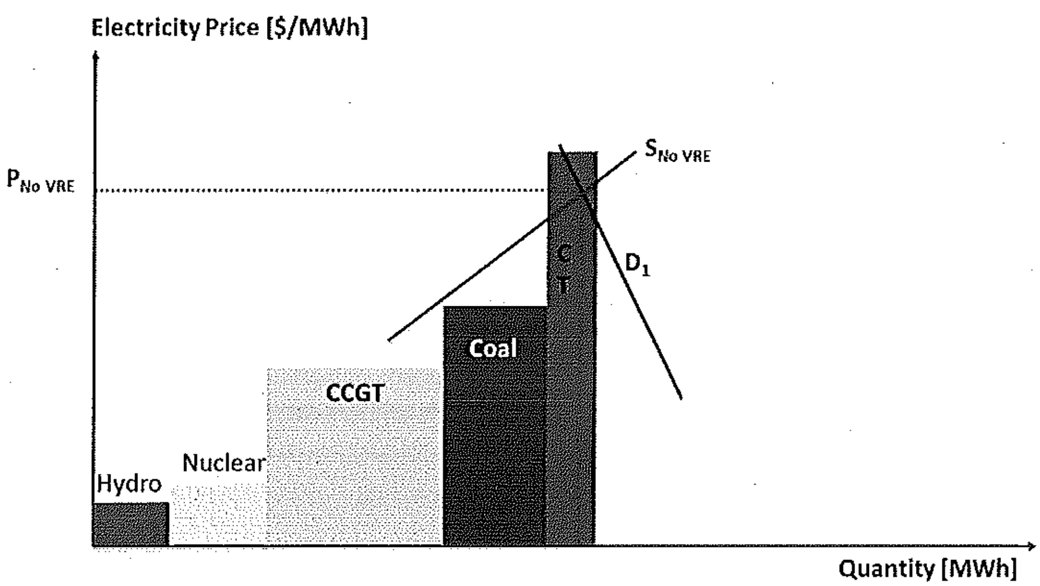

Figure 1 Price Formation without VRE Generators

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.

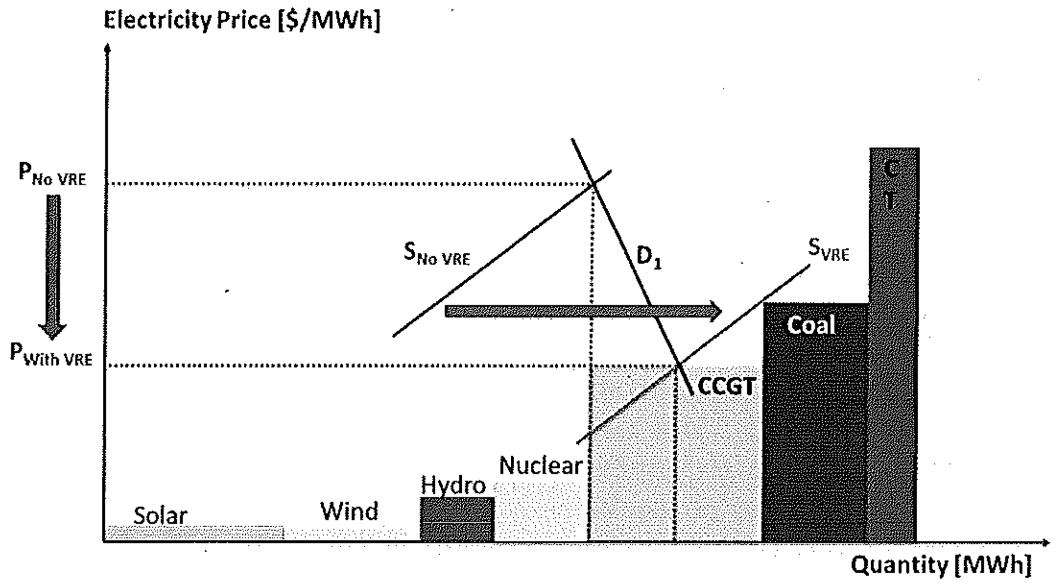

Figure 2 Price Formation with VRE Generators

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.

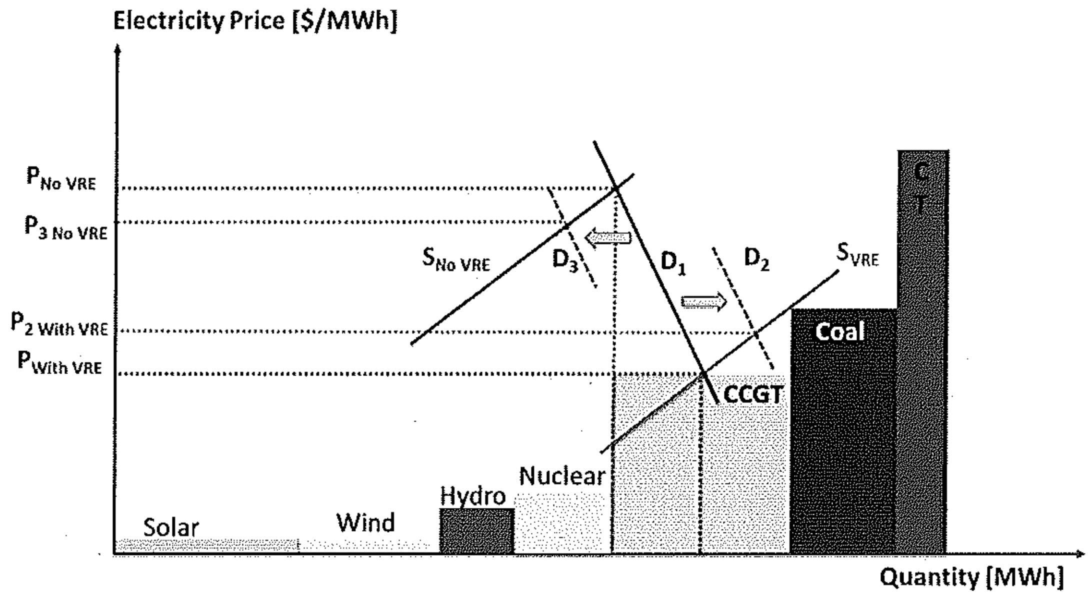

Figure 3 Potential for Demand Changes that Shift Load into Periods with VRE Generation

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
Demand-Side Decisions	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
Demand-Side Decisions	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]

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[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.

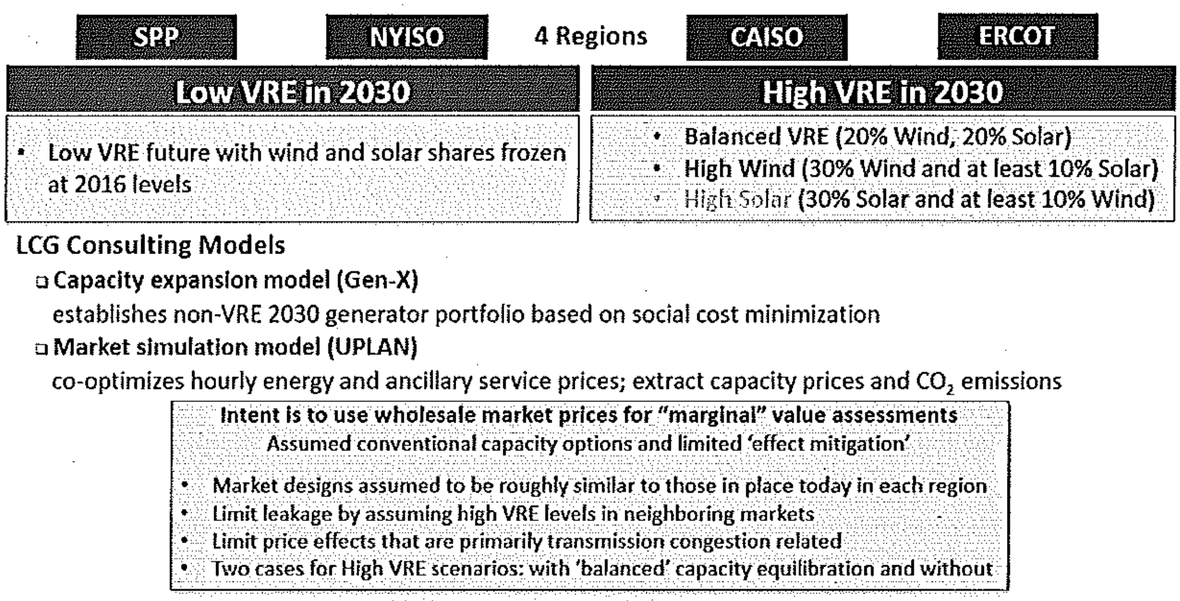


Figure 4 Research Design for Assessment of Wholesale Market Outcomes in 2030

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]

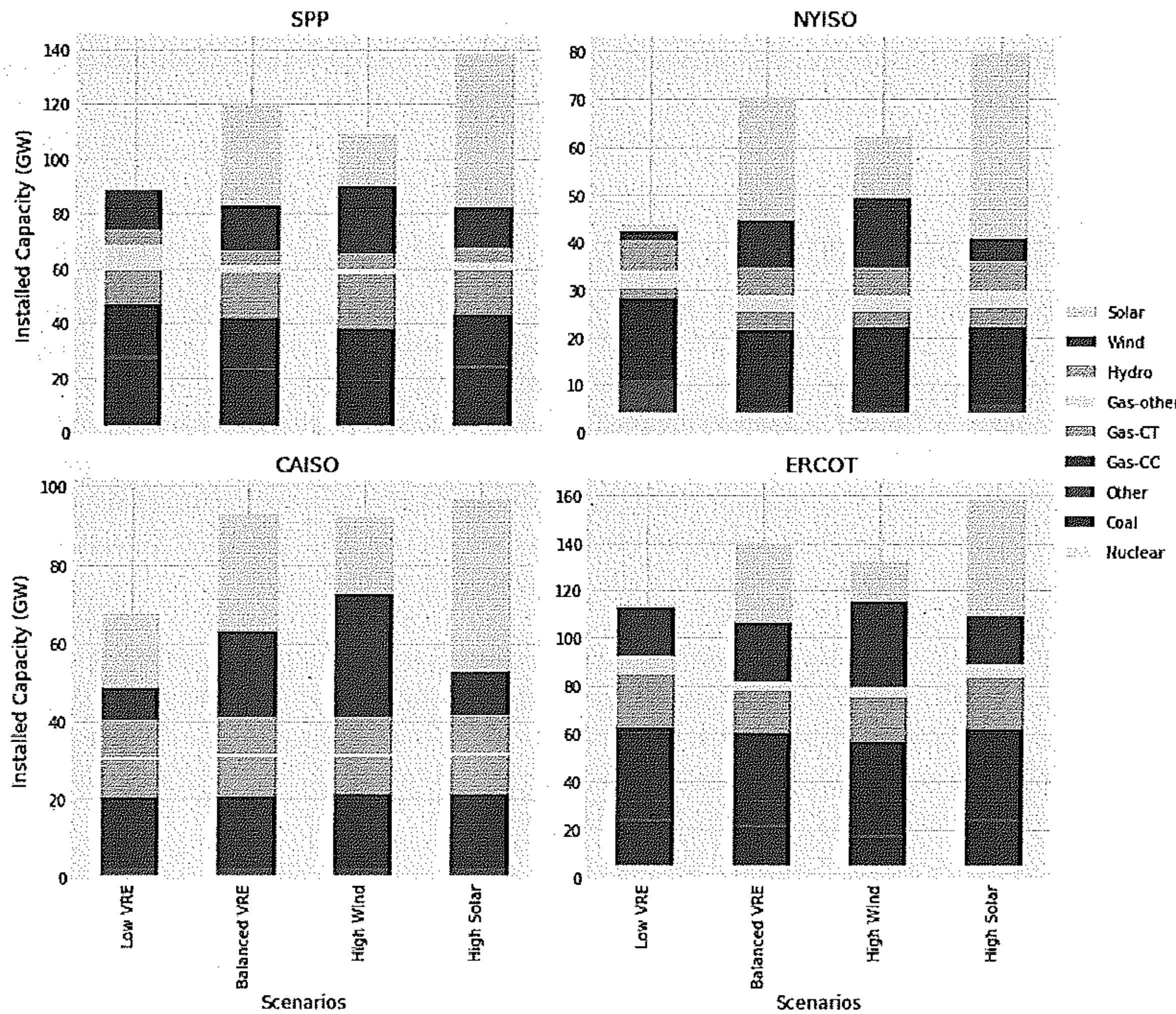
5.1 VRE Growth Results in Modest Net-Retirement of Firm Capacity

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.



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.

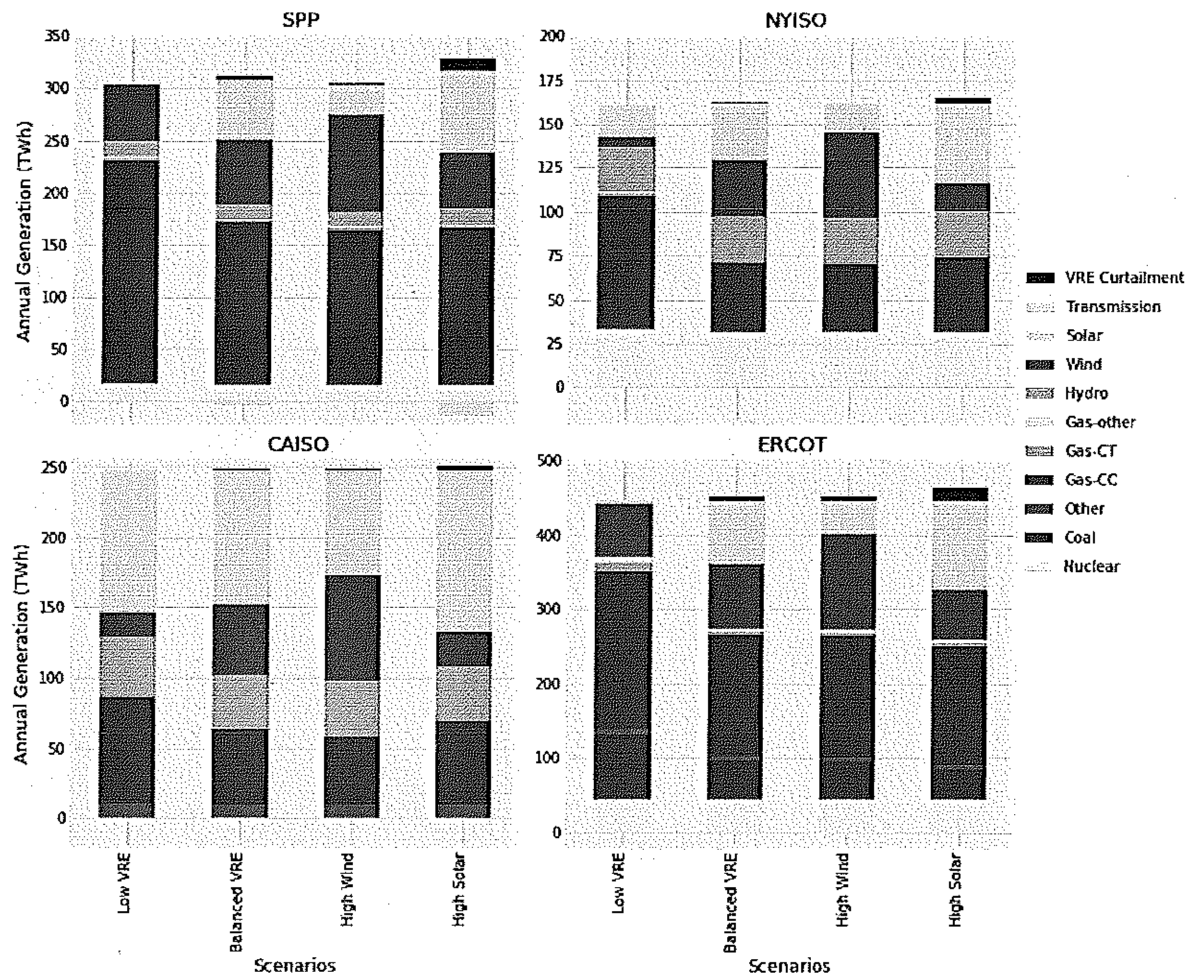
5.2 Energy from VRE Primarily Displaces Coal and Natural Gas Generation

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).



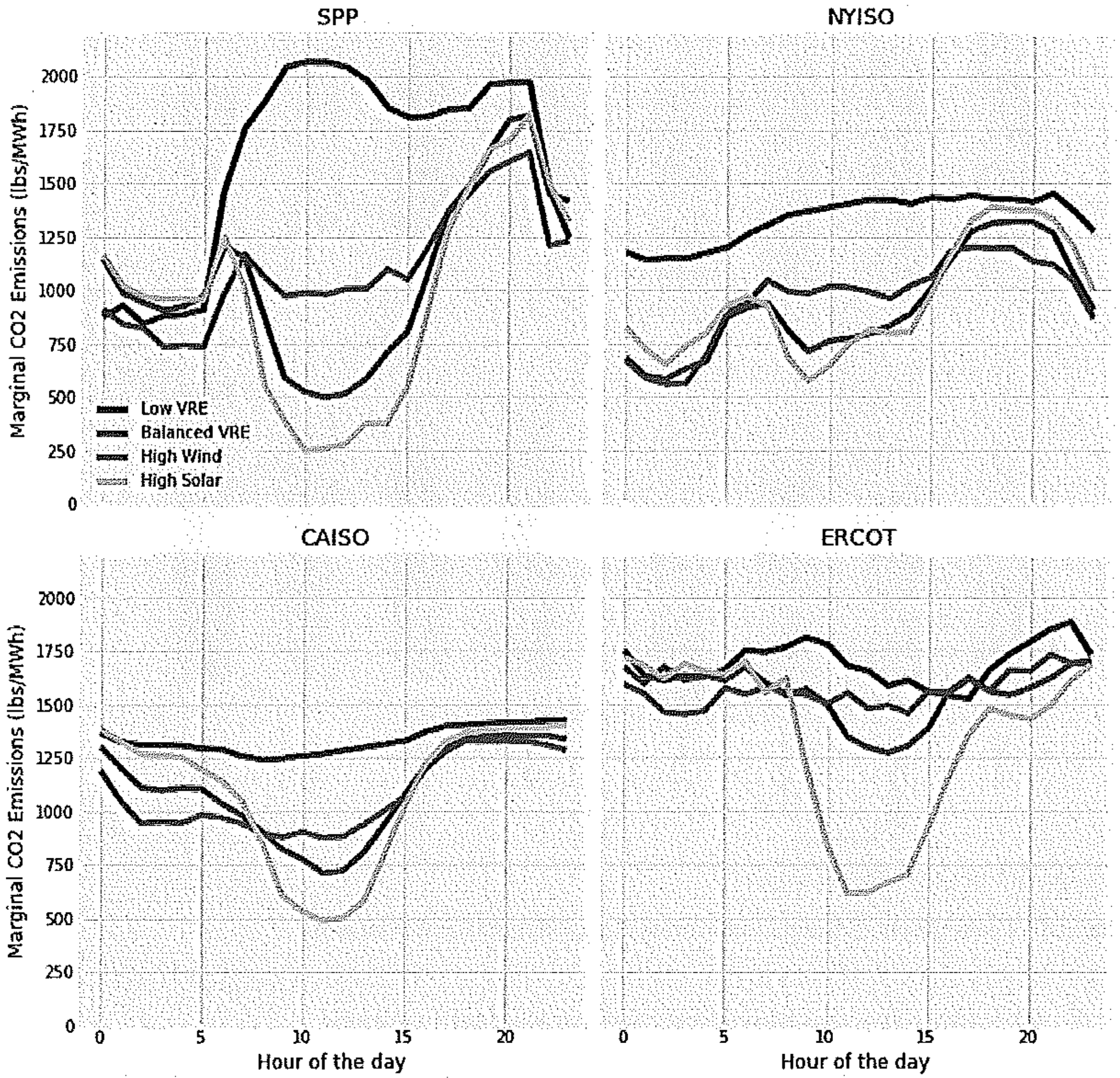
Source: LCG UPLAN-NPM simulation

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.

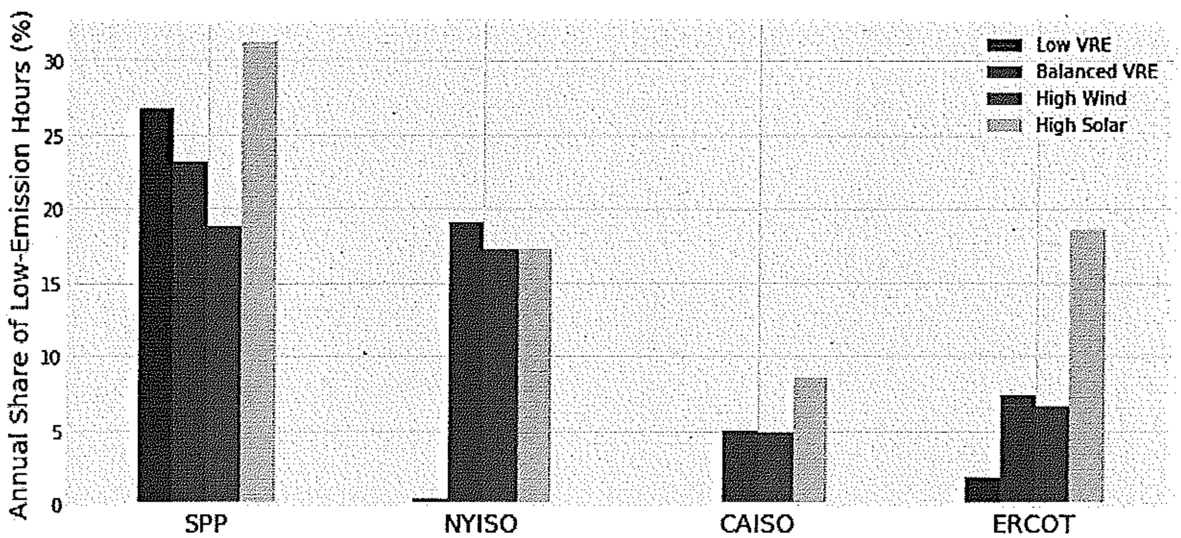


Source: LCG UPLAN-NPM simulation

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.



Source: LCG UPLAN-NPM simulation

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

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[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.

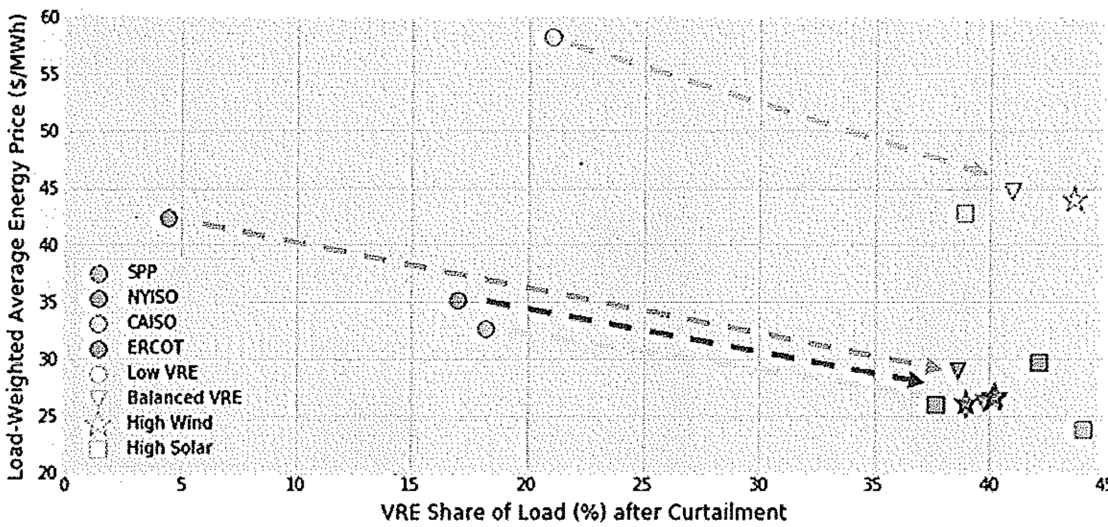


Figure 9 VRE Share of Load vs. Load-Weighted Average Energy Prices by Region

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.

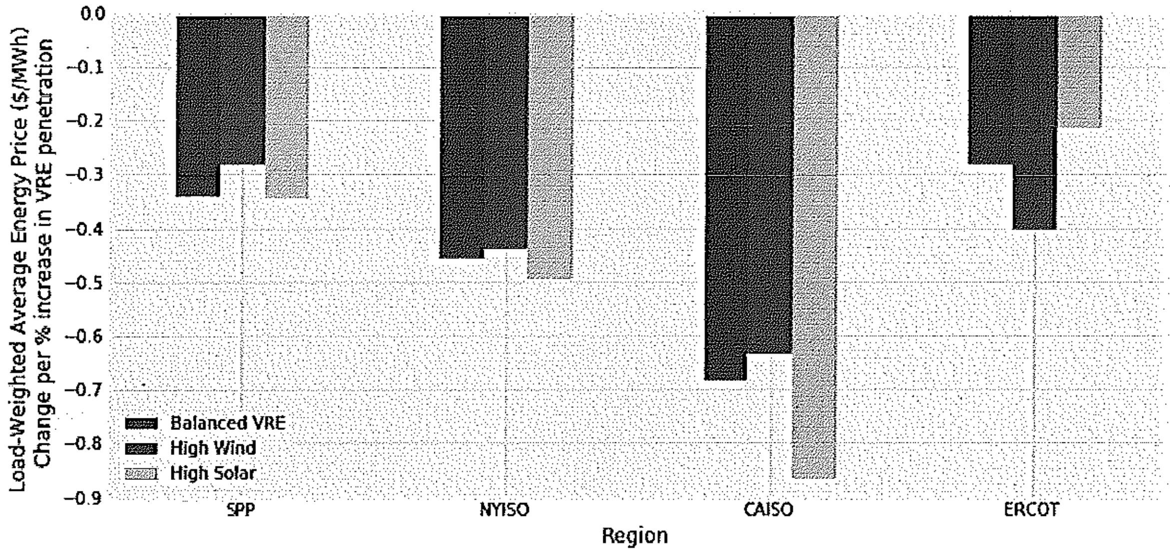
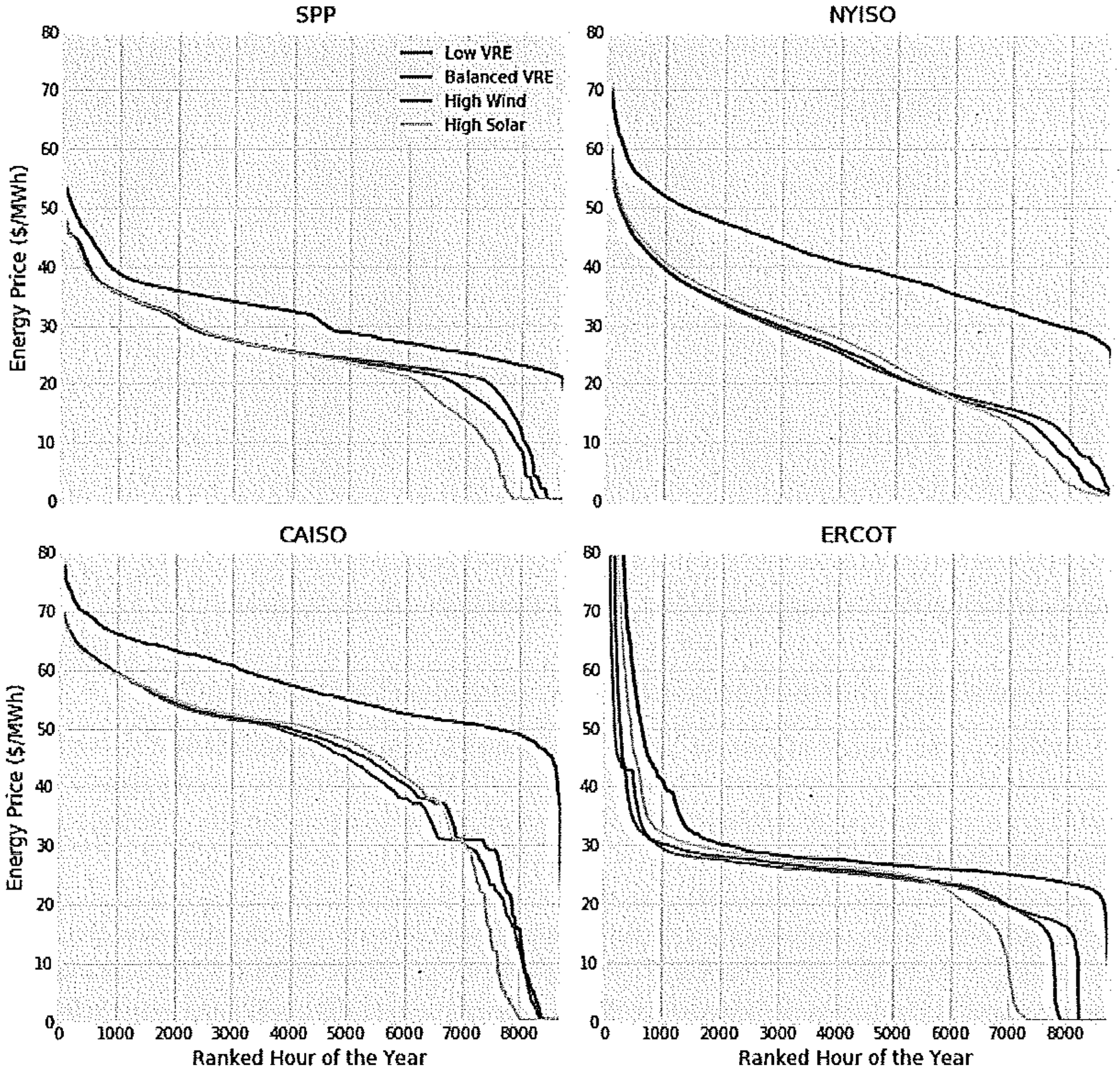


Figure 10 Energy Price Change with Increasing VRE Penetration Across Regions

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.

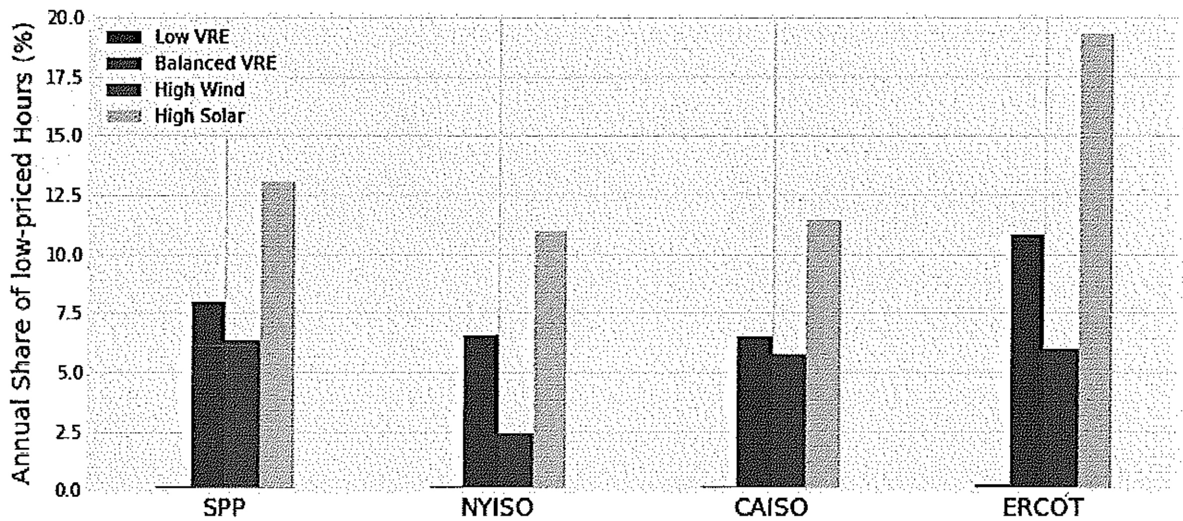


Source: LCG UPLAN-NPM simulation

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.



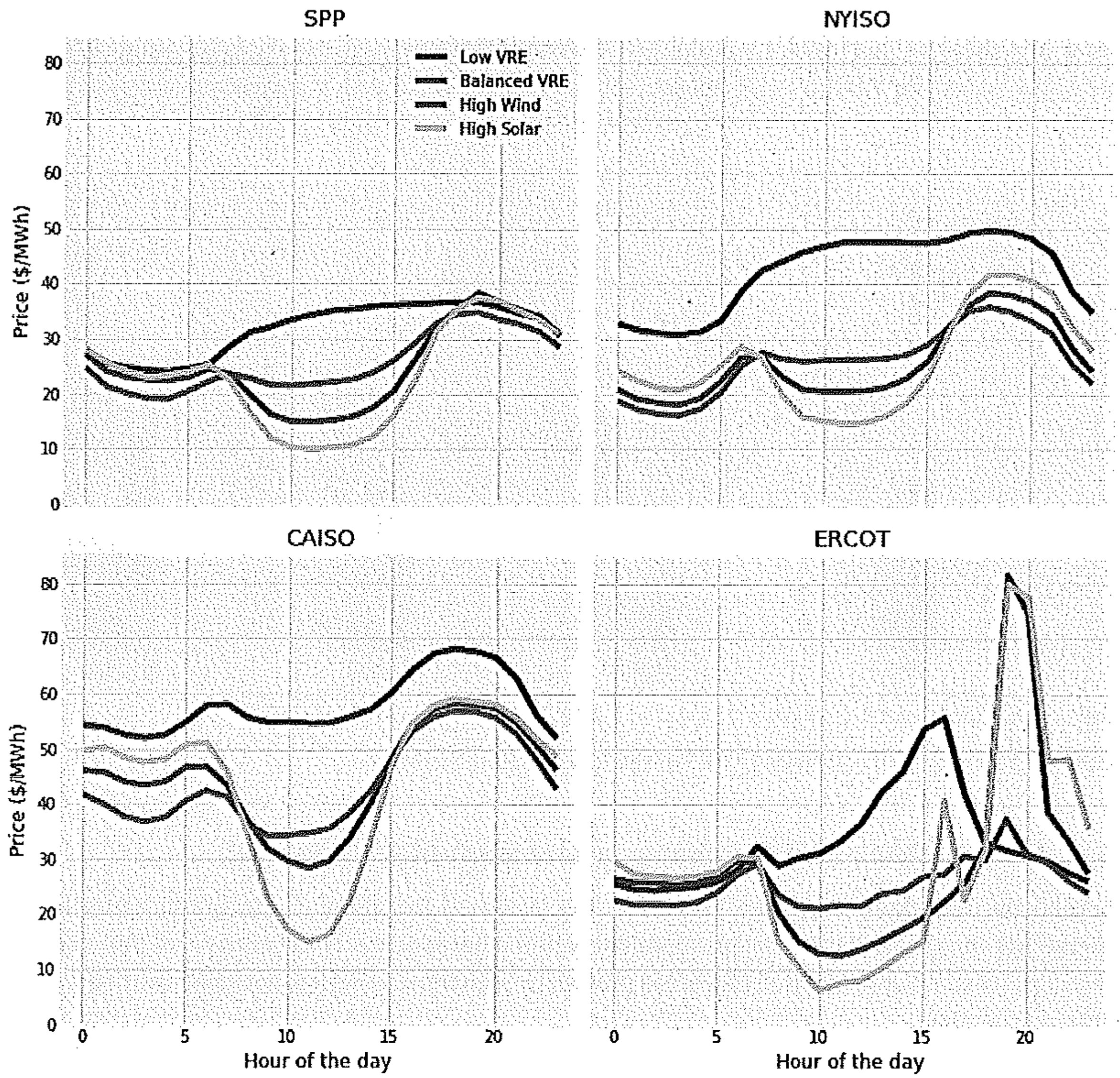
Source: LCG UPLAN-NPM simulation

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.

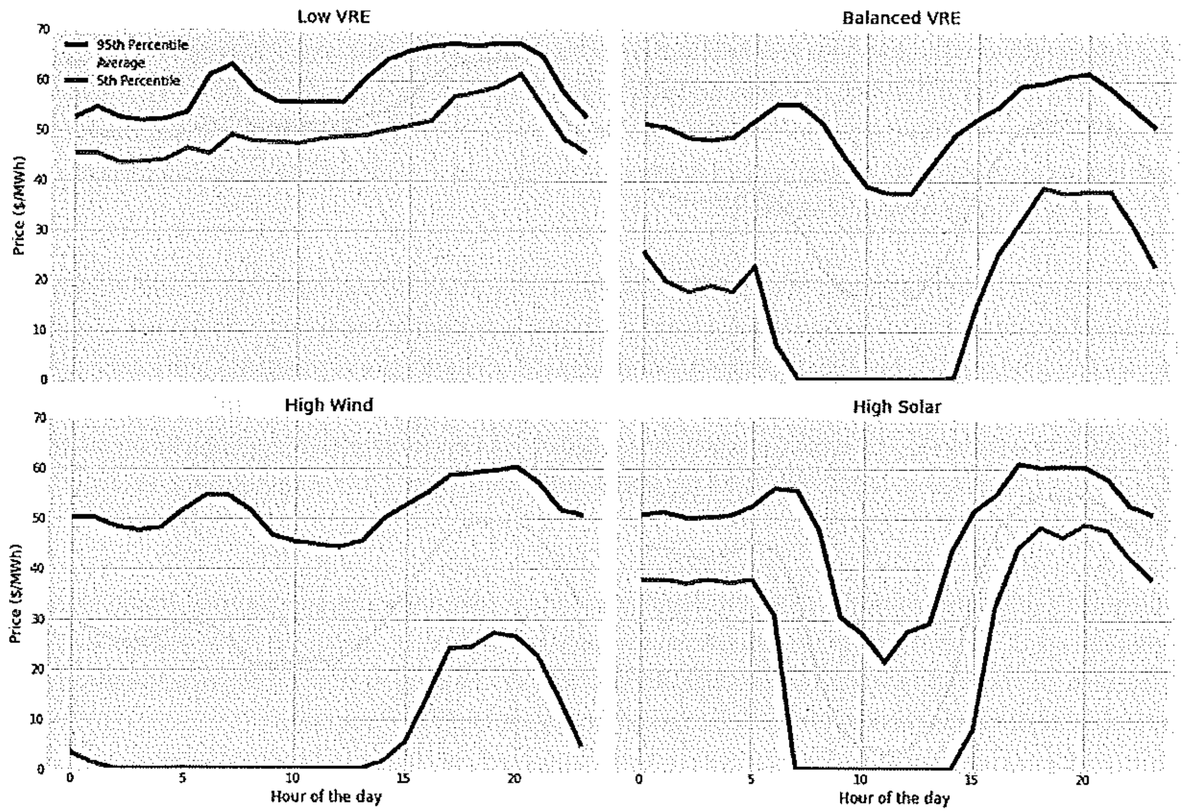
These changing diurnal price profiles highlight the value in adapting strategies for load-based resources (e.g., focusing on evening load reductions through residential or street lighting energy efficiency measures or favoring managed residential electric-vehicle charging to not further exacerbate evening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

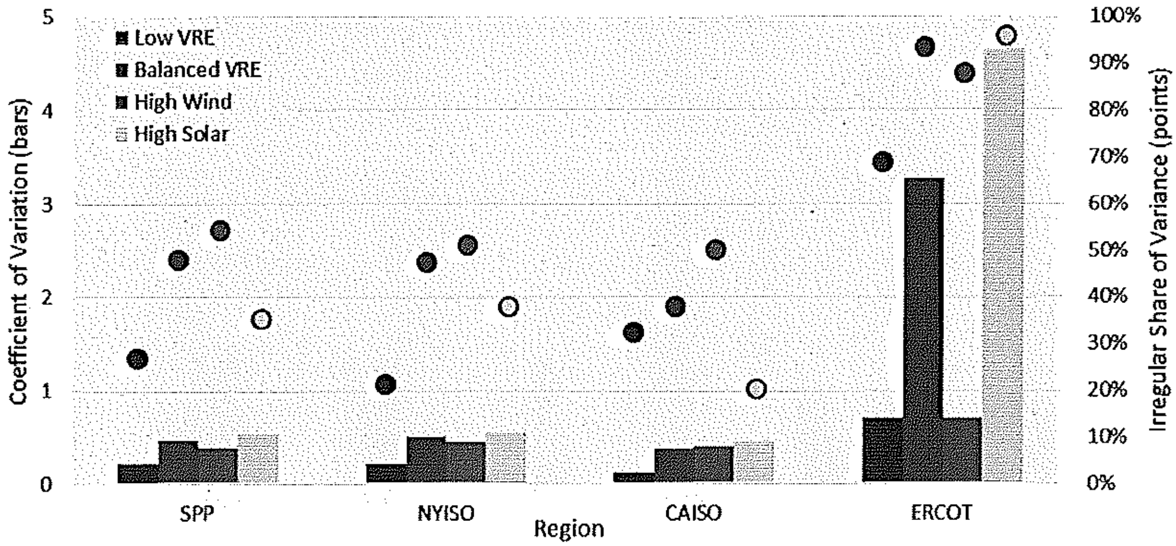
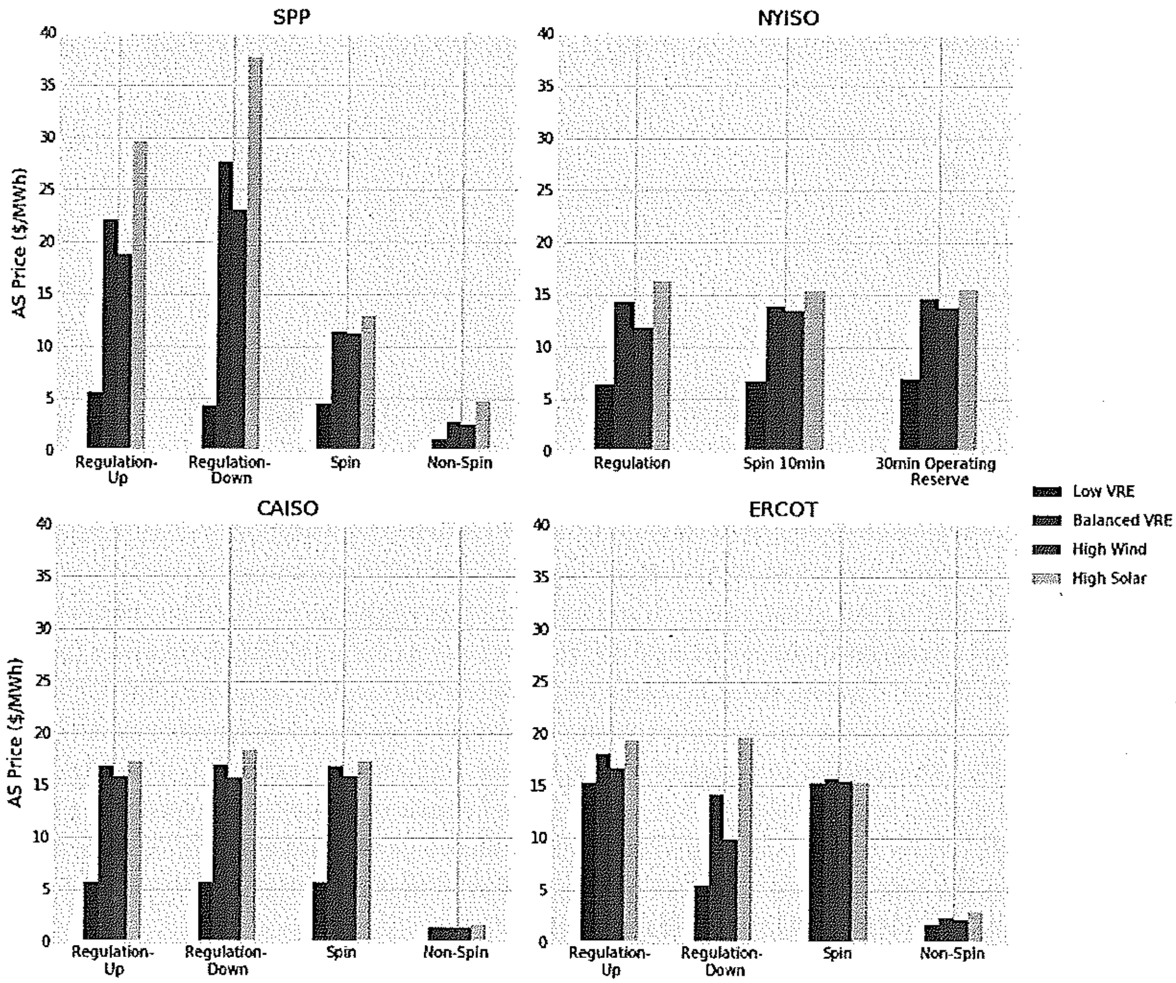


Figure 15 Coefficient of Variation and Irregular Fraction of Variance of Energy Prices Across Regions

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

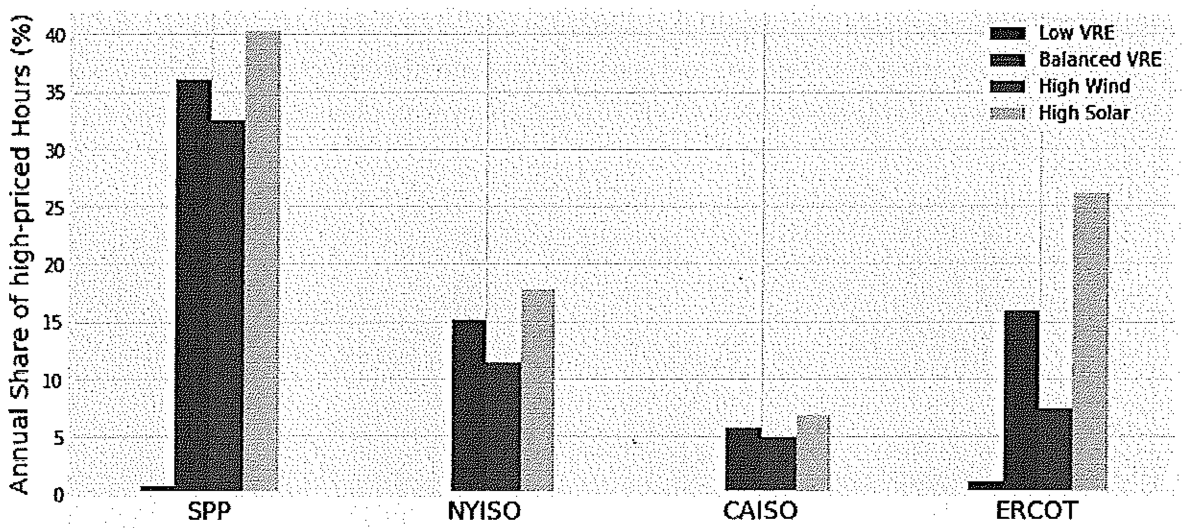
Figure 16 Average Ancillary Service Prices Across Regions

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).



Source: LCG UPLAN-NPM simulation

Figure 17 Share of Hours with Regulation-Down Prices Above $25/MWh

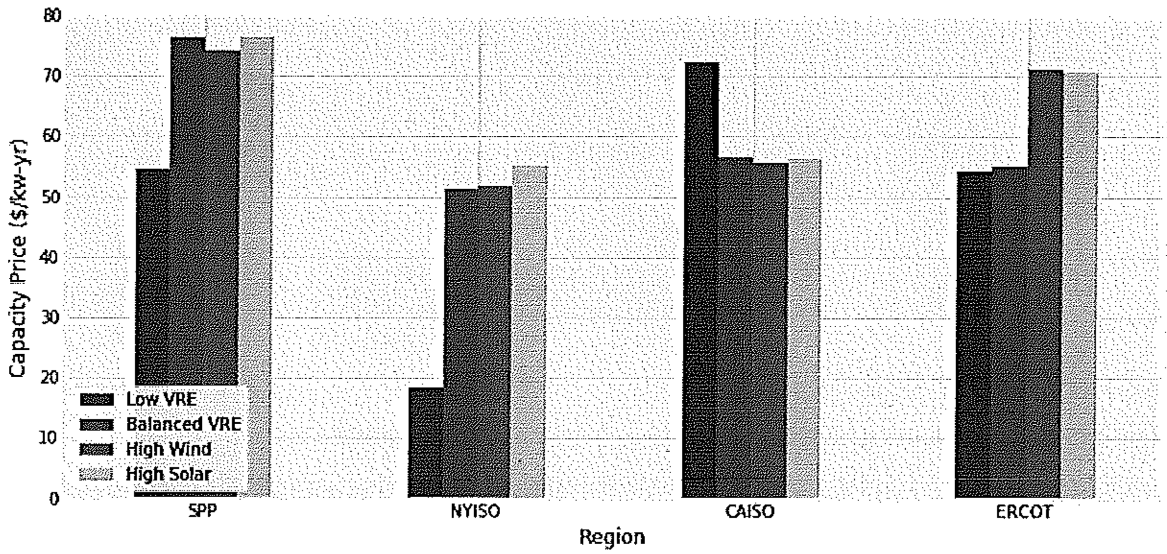
Furthermore, diurnal AS price profiles often significantly change with increasing VRE penetration as does their volatility around a given average hourly price level. For example, the high solar scenarios often lead to an increase in the price for regulation-down in the middle of the day relative to the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

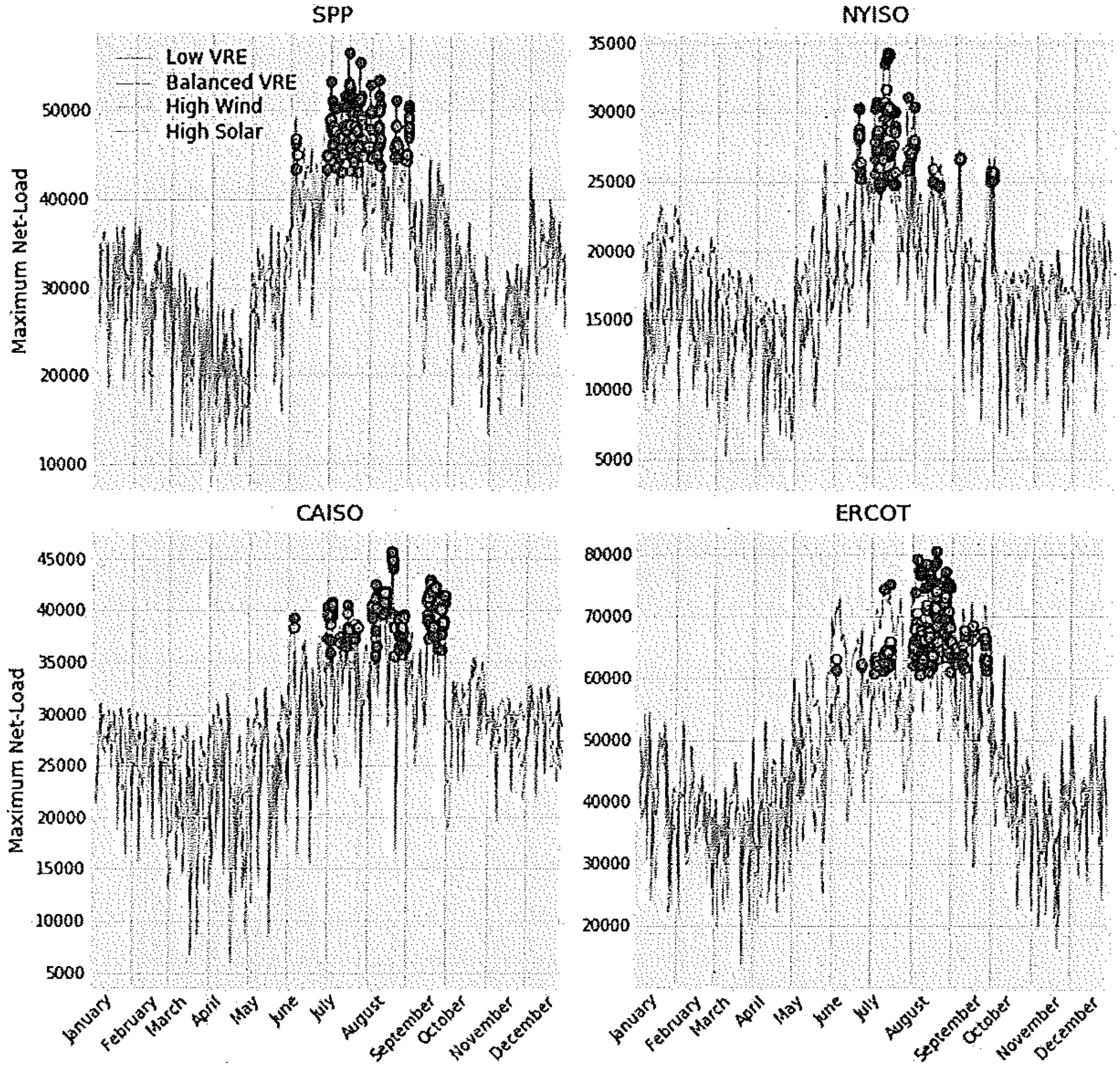


Figure 19 Daily Maximum Net-Load (lines) and Top 100 Net-Load Hours (dots)

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.

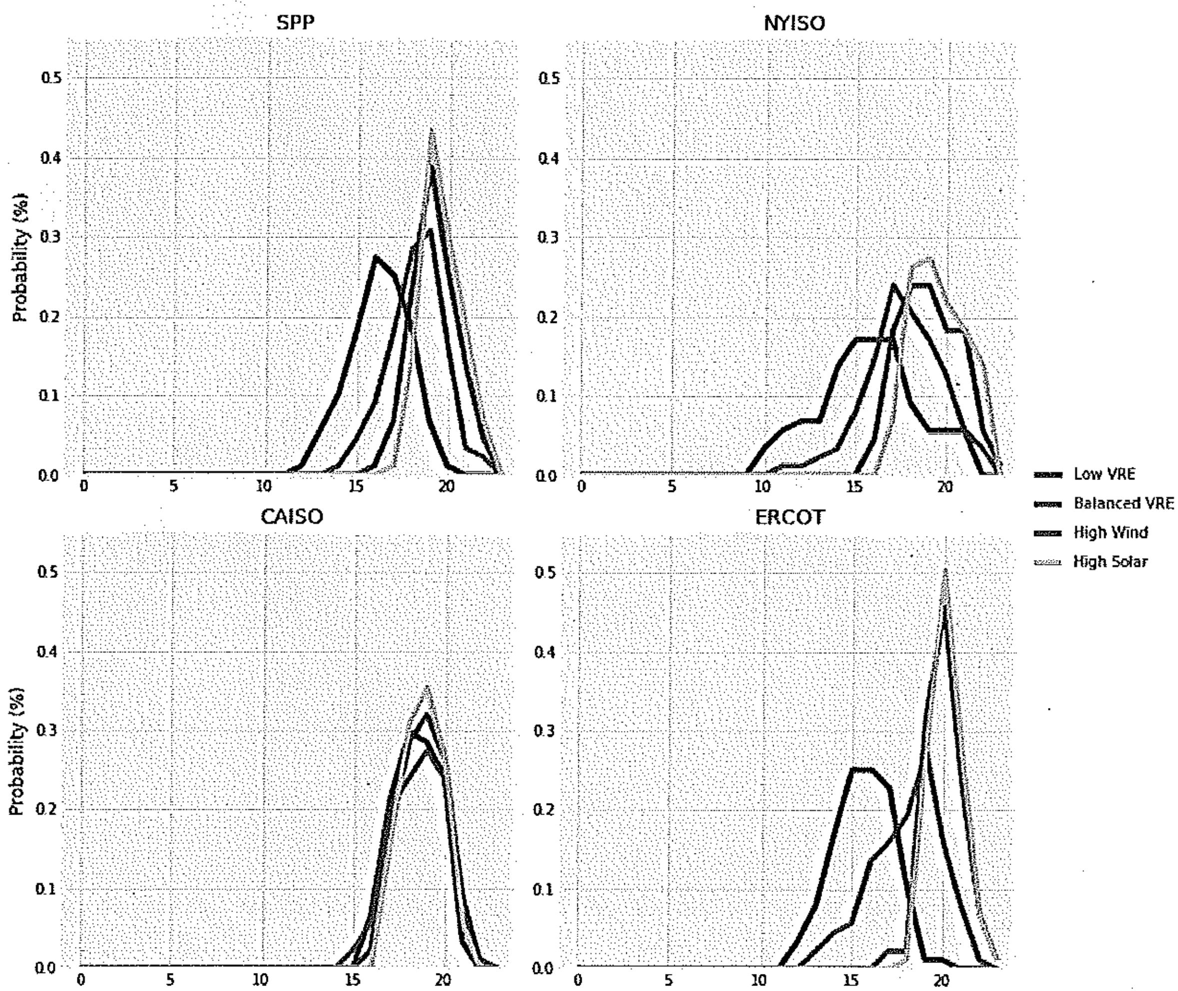


Figure 20 Probability that Hour is within the Highest 100 Net-Load Hours of the Year

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.

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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]

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[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

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Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience

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Challenges for wholesale electricity markets with intermittent renewable generation at scale: The U.S. Experience

Paul L. Joskow[1]

Abstract: The supply of intermittent wind and solar generation with zero marginal operating cost is increasingly rapidly in the U.S. These changes are creating challenges for wholesale markets in two dimensions. Short term energy and ancillary services markets, built upon mid-20th century models of optimal pricing and investment, which now work reasonably well, must accommodate the supply variability and energy market price impacts associated with intermittent generation at scale. These developments raise more profound questions about whether the current market designs can be adapted to provide good long-term price signals to support investment in an efficient portfolio of generating capacity and storage consistent with public policy goals. The recent experience of the California ISO (CAISO) is used to illustrate the impact of intermittent generation on supply patterns, supply variability, and market-based energy prices. Reforms in capacity markets and scarcity pricing mechanisms are needed if policymakers seek to adapt the traditional wholesale market designs to accommodate intermittent generation at scale. However, if the rapid growth of integrated resource planning, subsidies for some technologies but not others, mandated long term contracts, and other expansions of state regulation continues, more fundamental changes are likely to be required in the institutions that determine generator and storage entry and exit decisions.

Key Words: electricity, renewable energy, intermittency, wholesale electricity markets

JEL classification: L51, L94, L98, Q41, Q48, Q55

I. Introduction

This paper examines the current and likely future effects on wholesale electricity markets and the challenges these markets face due to the rapid expansion of intermittent (or variable) renewable energy,

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[1] Elizabeth and James Killian Professor of Economics, MIT and Research Associate, National Bureau of Economic Research. The views expressed here are my own and do not reflect the views of MIT, the National Bureau of Economic Research or any other entities with which I an affiliated. I am grateful to Richard Schmalensee for extensive discussions of many of the issues discussed in this paper and to Patrick Brown for providing assistance in organizing and displaying the CAISO data. The CAISO data displayed in the figures come from the CAISO web site and are all publicly available. http://oasis.caiso.com/mrioasis/logon.do . The daily generation data were collected from the CAISO web site and organized in the Platts Megawatt Daily Fundamental Data to which I subscribe. MIT provided support for my research. A list of my affiliations can be found at http://economics.mit.edu/files/15081. I note in particular that I am on the board of directors of Exelon Corporation which has an interest in the issues discussed here, though I have not discussed with Exelon the content of this paper. Finally, Deiter Helm and two and two anonymous referees have provided very helpful comments on an earlier version of this paper.

primarily wind and solar, with close to zero marginal generating costs. Generation "intermittency" of wind and solar is a consequence of the natural variations in wind speeds and directions and available sunlight at specific locations and at specific times. The increase in wind and solar generation is already having significant effects on wholesale markets in some regions of the U.S. Solar and wind generation collectively are expected to become major sources for generating electricity (grid-based and distributed on homes and commercial establishments) in many regions of the U.S. by 2050.

Wind and solar will continue to expand rapidly in the U.S. despite the current posture of the Trump administration toward policies to mitigate CO2 emissions in order to fight climate change. While the Trump administration has rejected concerns about climate change and has sought to curtail federal policies to promote renewable energy and energy efficiency, the majority of U.S. states have adopted policies to facilitate the deployment of more wind and solar to meet their own CO2 emissions reduction goals.[2] Hawaii and California have goals of 100% carbon free electricity by 2050 and other states are ramping up their goals for aggressive expansions of wind and solar and adopting policies to turn these goals into reality. Federal tax incentive policies for renewable energy remain in force, though they will phase down or out over the next few years. Moreover, the Federal Energy Regulatory Commission (FERC) continues to issue rules affecting wholesale power transactions and the use of the grid that are friendly to the efficient integration of wind and solar, the increased deployment of storage, and the integration of an active demand side into wholesale markets. Finally, the cost of wind and solar have declined dramatically over the last decade and are increasingly competitive with gas-fueled alternatives even without special support mechanisms (LBL, 2018a, page 14).

[2] Thirty-one states have mandatory renewable energy portfolio standards (REPS). Another 8 states have established voluntary targets for increasing the penetration of carbon free generation. The states without REPS are primarily in the South. National Conference of State Legislatures, http://www.ncls.org/energy/renewable-portfolio-standards.apsx. Other sources have slightly different numbers. See the DSIRE web site operated by the North Carolina Clean Energy Technology Center http://www.dsireusa.org/.

High penetration of intermittent generation with zero marginal operating costs creates challenges for wholesale market designs. And it is *both* intermittence and zero marginal operating that are important. To oversimplify, wholesale markets as they are now structured in the U.S. perform two related resource allocation functions --- short run and long run. First, they provide for the efficient real-time operation of existing generating capacity, clear supply and demand at efficient wholesale prices that represent the marginal cost of supply at any moment, and do so while maintaining the reliability of the system. Second, market prices and price expectations are supposed to provide efficient long run profit expectations and incentives to support efficient decentralized investments in new generating capacity and efficient retirements of existing generating capacity. Wholesale market designs in the U.S. that evolved since the late 1990s now do a reasonably good job supporting the first set of short run resource allocation tasks under most states of nature. However, they have been challenged in providing adequate financial incentives to support efficient entry (investment) and exit decisions consistent with reliability criteria established by system operators. That is, the short run price signals do not lead to long run price expectations that adequately incent efficient investment and retirement decisions. The disconnect emerges primarily as a result of energy and ancillary price formation during tight supply and other stressed conditions. Prices under these conditions do not rise high enough to reflect the scarcity value of the generation due to price caps, limited demand-side participation in the wholesale market, and out-of-market actions by system operators during network security emergencies (Joskow 2007). This in turn has led to the development of a variety of "resource adequacy," capacity obligation, capacity pricing, and scarcity pricing mechanisms.

The expansion of intermittent generation with zero marginal operating cost creates additional challenges for wholesale markets in both the short run efficient operating dimension and the efficient investment dimension. Wind and solar benefit from a variety of direct and indirect subsidies and opportunities to compete for long term contracts. As supplies from these resources expand, spot market prices for energy decline and the net revenues from energy prices provide declining quasi-rents to support unsubsidized investment. While the "missing money" or net revenue adequacy problem is not new, I expect that inadequate entry and exit incentives will turn out to be more severe from the perspective of unsubsidized generation as the supply of favored intermittent generation grows. These developments are likely to lead to more profound changes in the design of competitive wholesale markets in the U.S. than the current approach of simply tinkering with current market designs. The growing importance of intermittency will require new market products and services to ensure an efficient and reliable system. The impact of the growing importance of this zero marginal cost generation further undermines incentives for decentralized investment in generating capacity that can efficiently provide these services (e.g. fast response turbines and batteries) as spot energy prices decline and imperfections in capacity markets and scarcity pricing mechanisms have a growing impact on investment incentives. We are moving away from a decentralized model based on market incentives to a model where some technologies rely heavily on subsidies, long term contracts, and other out-of-market revenues to support their capital costs and others must rely on the market for all of their revenues. This is an unstable and inefficient model. It is a slippery slope where subsidies and special contracts lead to more subsidies and more special contracts guided by centralized resource planning rather than decentralized market incentives.

This paper proceeds as follows. The next section discusses the growth of wind and solar generation in the U.S. and the federal and state policies that have promoted it. The paper then turns to a discussion of the wholesale electricity market designs that have been adopted by RTO/ISOs (Regional Transmission Organizations and Independent System Operators) and supported by the Federal Energy Regulatory Commission (FERC) in the U.S. and the performance attributes of these markets. The theoretical bases for these market designs are discussed next along with some recent theoretical work on how the markets will be affected by the transition to systems dominated by wind and solar. The wholesale market in California managed by the California ISO (CAISO) is presently the most interesting in the U.S.[3] This is the case because the penetration of intermittent generation, especially the penetration of solar which is more "interesting" than wind, is far more advanced than is other parts of the U.S., making it possible to see some of the impacts more clearly in practice. Accordingly, I use the CAISO experience to examine changes in generation supply, spot energy pricing, entry and exit patterns associated with intermittent generation at scale. We can think about this as a sort of case study. The final substantive section puts the theoretical and empirical evidence together to highlight challenges to prevailing wholesale market designs and potential responses to these challenges.

The paper then turns to a discussion of wholesale market design challenges and potential changes in wholesale market designs in response to these challenges. This discussion focuses heavily on long term investment incentives, storage, and dynamic prices. I conclude with some observations about more fundamental changes taking place in the U.S. the U.S. in response to growing state intervention in electricity markets through integrated resource planning, renewable portfolio mandates, subsidies, resource adequacy policies and long term contracting obligations. Short run resource allocation through competitive energy and ancillary service markets are adapting to the challenges of intermittent generation at scale. However, the philosophy of free entry and exit driven by market forces rather than regulatory requirements is rapidly being replaced with extensive government intervention affecting the kinds of resources that will enter and exit a market and how they will be compensated. This transition

[3] In most cases, when I refer to California, I will be referring to the portion of California governed by the CAISO. The CAISO covers about 80% of the wholesale electricity supplied to California citizens. Some public power entities, including the Los Angeles Department of Water and Power which supplies electricity to the City of Los Angeles, have chosen not to be part of the CAISO.

will proceed more efficiently if we recognize that it is coming and adjust the procurement process accordingly.

II. The growth of intermittent renewable generation in the U.S.

For at least a decade the U.S. has adopted and implemented a variety of policies to encourage investment in wind and solar energy. More recently, federal and state policies have expanded to promote and support the expansion of grid-based and behind the meter (BTM) storage as well, as it becomes clear that due to intermittency, aggressive solar and wind penetration goals cannot be achieved at reasonable cost without storage. (I will discuss storage per se later in the paper.) At the federal level, there are a variety of tax subsidies for grid based solar energy, grid-based wind energy, "behind-the-meter (BTM) "rooftop" or "distributed" solar photovoltaic (PV) and wind energy facilities.[4] These subsidies and incentives include federal investment tax credits for solar (both grid-based and BTM) and wind or production tax credits for wind.[5] Many states offer additional subsidies. These include specific dollar tax credits or grants, investment tax credits, exemptions from sales taxes, marketable renewable energy certificates, and the implicit subsidies associated with binding renewable energy portfolio mandates which many states have adopted.[6] The investment tax credit subsidies can typically be extended to cover storage if the storage is integrated with wind or solar facilities eligible for these credits. The FERC has issued an order requiring RTO/ISOs to develop rules to allow storage to compete with generation on a level playing field and a number of states have extended direct and indirect subsidies to storage to support expansion goals.[7] A

[4] Federal tax subsidies are also available for geothermal, biomass, fuel cells, and other technologies. Though these technologies are not intermittent, they are likely to remain a small share of the generation portfolio for the foreseeable future.

[5] The federal tax subsidies for solar and large-scale wind decline over the next few years. For solar the investment tax credit falls from 30% today to 10% in 2022 (zero for residential installations). For wind the production tax credit is schedules to end after 2022. https://www.energy.gov/savings/business-energy-investment-tax-credit-itc

[6] For a complete list of state incentive programs see http://www.dsireusa.org/.

[7] FERC Order 841, effective June 4, 2018.

growing number of states have paired renewable portfolio mandates with requirements that distribution utilities enter into long term contracts with solar and wind generators through a competitive procurement process. A similar approach is slowly emerging for grid-based storage. In several states, these explicit and implicit subsidies cover a large fraction of the investment costs in wind and solar facilities.

In addition, 38 states and the District of Columbia have adopted "net-metering" rules for residential and small commercial customers.[8] These rules effectively allow behind the meter solar facilities to get credit for 100% of the entire retail *revenues* avoided or displaced by their generation rather than their --- much lower --- actual avoided *costs.* [9] This results from the fact *(a)* that the bulk of residential and small commercial distribution and transmission costs are recovered through relatively flat per Kwh usage charges rather than per customer charges or coincident peak demand charges, *(b)* generation, distribution, transmission and other charges are not unbundled in many states, *(c)* states have not required that dual meters or smart inverters with data collection and retrieval capabilities be installed so that purchases from the grid and sales to the grid cannot be measured separately, and *(d)* even in states that have deployed real time meters, real time pricing and settlements have not yet been widely adopted.

Thus, if the avoided generation and distribution costs resulting from generation by a rooftop PV facility is say 6 cents/Kwh (e.g. the wholesale market price for generation plus losses plus avoided distribution costs) while the marginal bundled retail price is 20 cents/kwh, a rooftop PV installation effectively receives 20 cents/kwh that it generates rather than the 6 cent/Kwh avoided wholesale market generation and avoided distribution cost. While rooftop PV may indeed avoid some distribution and transmission costs,

[8] Several states have placed limits of one kind or another on access to net metering compensation.

[9] Having learned its lesson from the Public Utilities Regulatory Policies Act (PURPA) experience, the U.S. does not generally rely on feed-in tariffs for grid-based renewables. However, net metering for BTM PV is effectively a high feed-in tariff.

careful analysis shows that these savings are very small (Cohen and Callaway, 2016; Cohen, *et. al.* 2016) and far below the average cost of distribution networks reflect in per Kwh retail tariffs. There is also evidence that the wide diffusion of rooftop PV facilities increases local distribution costs rather than decrease them as investments in remote monitoring and control capabilities, new transformers and capacitors, and other "smart grid" investments are required to manage short-term variations in PV production and reverse flows to maintain distribution network operating criteria and avoid outages and equipment overloads (Wolak, 2018a). It is clear that if there are avoided distribution and transmission costs, the cost saving is much less than the average total cost of distribution and transmission reflected in regulated retail per Kwh rates, so in this sense net metering provides a subsidy.

Not only does net metering provide a large subsidy for BTM PV but the subsidy from net metering is paid for by shifting regulated distribution and transmission costs from those with rooftop PV systems to those without. This cost shifting has unattractive income distribution consequences (Wolak 2018a). As a consequence, a number of states have capped the availability of net metering, required smart inverters or meters to measure BTM generation, and begun to reform distribution rate designs. Not surprisingly, these changes have been vigorously opposed by environmental groups, BTM PV suppliers and installers.

One of the stated goals of the various subsidy programs has been to help wind and solar technologies to move down a learning/innovation curve and achieve economies of scale in production and installation so that they would eventually become a competitive carbon free alternative to fossil-fuel generation. Regardless of what the causal factors may have been, the installed cost of wind and solar PV facilities (grid-based and rooftop PV) have fallen very dramatically over the last several years, making wind and solar competitive with new fossil generating capacity with similar load factors and output profiles at some locations even without subsidies, though these comparisons typically ignore the backup costs required to respond to intermittency in order to meet demand reliably (Gowrisankaran, Reynold, and Samano, 2016). For example, the National Renewable Energy Laboratory (NREL, 2017) reports that the prices for utility scale solar projects have fallen by about 2/3 since 2010 and rooftop PV by over 50% and these costs continue to fall. See also LBL (2018b, page 14). Grid-based PV is much less expensive than BTM PV, but the incentives for rooftop PV are much less generous in many states than are the incentives for BTM PV.

Table 1 displays the growth in wind and solar generation in the U.S. between 2010 and 2017. Grid-based solar has grown by a factor of over 40. Rooftop PV has grown by a factor of 10.[10] Grid-based wind has grown by a factor of 2.7. Overall, wind plus solar generation has grown from about 2% of total U.S. generation in 2010 to over 8% of total U.S. generation in 2017 and continues to grow rapidly. During this time period total generation to meet load has been flat. EIA projects in its reference case that by 2050 wind and solar (including behind the meter generation) will account for about 1,200 GWhs of generation on a national basis, or roughly 25% of total U.S. electricity generation (calculated from EIA AEO 2018, various pages).

The national figures mask wide differences between states reflecting state policy choices, the available wind and solar resources which vary widely across a large country like the U.S., and differences in the wholesale and retail prices of electricity in different regions which affect the ability of wind and solar to compete. In California (CAISO), grid-based solar and wind already account for about 18% of grid-generation and rooftop PV probably accounts for roughly another 5% for a total of 23% from wind and solar in 2017. However, on some days, when demand is relatively low, the wind is blowing, and the sun is shining, grid-based wind and solar account for as much as 60% of total grid-supplied electricity in some

[10] Rooftop PV generation is typically not measured directly today. These are estimates developed by the U.S. Energy Information Administration. There is a further discussion of the measurement of BTM PV generation below.

day-time hours while BTM PV further reduces the net demand on the grid at those times. While states like New Jersey and Massachusetts do not at first blush appear to be natural candidates for solar PV due to their Northern locations, the combination of state subsidies, in addition to federal subsidies, net metering and high retail rates (backed out by net metering), now make rooftop PV quite attractive in these states. States like Iowa, Nebraska, Oklahoma, Kansas and especially Texas have seen the installation of a lot of wind generators because of strong and steady winds which allow grid-based facilities with 40% to 50% capacity factors to be built and operated, resulting in what appear to be very competitive prices, taking into account the benefits of federal tax subsidies. California accounts for over 40% of U.S. solar generating capacity and a similar fraction of rooftop PV. In most other states solar generation lags far behind wind generation, but is forecast to grow more rapidly over the next few decades (EIA, AEO 2018, page 93). Over the last five years over half of the utility-scale generating capacity added in the U.S. was wind or solar. As things stand now, it looks like we will continue to see large differences among the states in the penetration of wind and solar as a result of variations in state policies, economic attractiveness and endowments of wind and sunshine.

INSERT TABLE 1

The average capacity or average annual production percentage from intermittent generation also understates the impacts that these resources are already having on wholesale power markets. Especially during times of low demand --- at night, during the day if there is a lot of solar on the system, on the weekend, in the spring, etc., intermittent generation can already account for a large fraction of demand. For example, about 20% of the generating capacity in the Southwest Power Pool (SPP), which stretches from Northwestern Texas to Montana and has the highest speed winds in the on-shore U.S., is presently accounted for by wind. However, wind generation exceeded 60% of total load at times during Spring, 2018. Another 44 GW of wind is in development. Solar accounts for only 1% of SPP's generating capacity at the present time, but 16 GW of solar has applied for grid connections, almost as much as the 18 GW of existing wind capacity.[11] In a few years there will be many hours each year when intermittent generation accounts for a large fraction of the load in several RTO/ISO areas.

III. Wholesale market design: overview

The wholesale market designs adopted by most RTO/ISOs in the U.S. and supported by the regulator (FERC) are "centralized" wholesale markets built upon a security constrained bid-based economic dispatch model that uses competitive multi-unit auction mechanisms to choose the least cost schedule and dispatch of generating plants to supply energy to meet demand, to manage congestion, to provide ancillary network services (frequency regulation, spinning reserves, etc.), and to derive market-clearing prices for these services.[12] These markets are managed "centrally" by the system operator and are built upon day-ahead auction markets that yield hourly day-ahead forward prices and commitments to supply and to purchase services, intra-day adjustment markets, real time balancing and settlements procedures and associated prices and dispatch actions. In most U.S. RTO/ISO markets, scheduling of generation and the management of transmission congestion are handled simultaneously via a security constrained bid-based economic dispatch mechanism that incorporates the attributes of the transmission network and reliability criteria. The security constrained bid-based dispatch (potentially) yields a very large number of day-ahead, intra-day, and real time nodal (locational) prices reflecting transmission congestion and reliability constraints. Bilateral physical contracts may also be submitted to system operators along with adjustment parameters to allow them to be integrated with the primary day-ahead and hourly adjustment markets. Buyers and sellers rely on independent futures markets to hedge financial commitments or to speculate on the future evolution of prices.

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[11] *Platt's Megawatt Daily*, August 7, 2018, by Kate Winston; Mike Ross, "SPP Overview," August 16, 2017, https://www.google.com/search?q=SPP+Overview&ie=utf-8&oe=utf-8&client=firefox-b-1.

[12] The MISO and SPP market designs have evolved more slowly than those in New England, New York, PJM, California and Texas. The states in the South and much of the Western region have not created this type of organized wholesale market and utilities remain vertically integrated.

Most of these organized markets have also evolved some kind of "resource adequacy" process to deal with the fact that "energy only" markets, especially with price caps (Joskow, 2007; Joskow and Tirole 2007), do not, in practice, as well as in theory, yield adequate revenues to respond to inefficient exits of existing plants and to attract new plants to meet reliability requirements. PJM, New England, and New York have developed similar organized capacity markets. Generators whose bids clear in the capacity market receive market-based capacity payments in addition to payments for supplying energy and ancillary services at market-based prices. In California, the California Public Utilities Commission (CPUC) has required load serving entities to contract forward for adequate capacity to meet their forecast loads during the next five (peak) summer months, but there is no organized market. The CPUC has recently announced expanding the requirement to up to five years, reflecting concerns that too many natural gas-fueled generators, needed to respond to intermittency and the large 4-hour ramp required to balance supply and demand as the sun goes down, were retiring (http://www.cpuc.ca.gov/General.aspx?id=6316). The Midwest ISO (MISO) has short-term resource adequacy requirements that can be supported by owning generation (many of the utilities in the MISO are still vertically integrated) or through bilateral contractual arrangements. Texas (ERCOT) has no resource adequacy requirement or capacity market. However, the price cap in Texas is $9,000/MWh, far above the price caps typical in other ISOs. The ERCOT market is an "energy-only" market relying on "scarcity pricing" rather than capacity payments to provide the marginal suppliers with quasi-rents (net revenues) that can cover investment costs in the long run (see below).

IV. Wholesale market design in the U.S.: A duality between central planning and wholesale market models

(i) Theoretical bases for RTO/ISO wholesale market design

It is important to understand the conceptual bases for current U.S. wholesale market designs to better understand the challenges created by the transition to intermittent carbon free zero short run marginal cost generation at scale. Perhaps ironically, the conceptual basis for the design of organized wholesale electricity markets in the U.S. during the late 1990s and early 2000s can be traced directly to the mid-20th century economic-engineering literature on optimal dispatch of and optimal investment in dispatchable generating facilities and the associated development of marginal cost pricing principles for generation services. These models were developed to apply to pre-restructuring vertically integrated electric utility monopolies subject to some kind of regulation, including government ownership (Boiteux (1949, 1960, 1951, 1956); Dreze (1964); Turvey (1968)). These models of generation dispatch, marginal cost pricing, and investment were eventually integrated with transmission network management and nodal pricing based on the work by Fred Schweppe and colleagues (1988).[13]

These old central planning models embodied the assumptions that electricity demand varies widely from hour to hour, that it is inelastic in the short run, that demand is controlled by consumers and not the system operator, except under shortage conditions when non-price rationing is applied by the system operator, and that the electricity generated to meet variable demand cannot be stored economically. Demand is not rationed by price but is exogenous and intermittent from the perspective of the system operator. The models also reflect that fact that the physics of electric power networks requires that the generation of electricity must exactly match the exogenous (to the system operator) variable and uncertain demand for electricity continuously in real time or outages and damage to equipment will occur.

[13] Boiteux (1949) also discussed the locational variation in prices due to transmission congestion.

This characterization of electricity demand and non-storability of generation made it convenient to represent demand over the course of a year with a load duration curve which specifies the number of hours during a year when load (demand) reaches a specific level from lowest duration (peak) to highest duration (base), but is not affected at all by short run variations in prices. This foundational theoretical work focused heavily on the supply side and the development of short run and long run marginal cost principles but little on the demand side which, due to metering, control, and pricing constraints was effectively treated as both variable and uncontrolled. This being said, it is not too difficult to extend the classic models of this genre to incorporate price sensitive demand as well (Joskow and Tirole, 2007).

On the generation supply side, the models specify a mix of *dispatchable* generating technologies. The technologies in the feasible set have different ratios of capital and operating (mostly fuel) costs. They are typically characterized as peaking technologies that have relatively low capital costs and relatively high operating costs (e.g. combustion turbines), mid-merit generating technologies with higher capital costs and lower operating costs (e.g. steam turbines fueled with oil, gas or both), and base load generating technologies (e.g. coal and nuclear) with still higher capital costs and lower operating costs.[14] The optimal investment problem is then to identify a mix of peaking, mid-merit, and base load capacity that exactly meets the load duration curve at minimum total cost. Once the optimal dispatchable generation mix is defined, a generation dispatch curve representing the short run marginal operating costs of supplying any specific level of demand can be defined. Generators are dispatched in merit order along this dispatch curve from lowest cost to highest marginal operating cost to meet demand plus operating reserves and ancillary network support services at each point in time. The marginal operating costs of the marginal generator required to balance supply and demand at each point in time also defines the short run marginal

[14] Green and Vasilakos (2011) depicts graphically this classical model nicely. Joskow (2008) contains a numerical example of this model enhanced with a "technology" that allows demand to be curtailed based on the "value of lost load."

cost of supplying each level of demand. Over time, this classic model was enhanced to include demand uncertainty, demand curtailments (outages), short-run demand response, stored (dispatchable) hydro-electric technology, planning and operating reserves, and network support services such as frequency regulation, and spinning reserves. Joskow and Tirole (2007) contains a more complete development of this classical model that includes price sensitive and price insensitive demand, a continuum of generating technologies, and network outages, in a market rather than a planning context.

(ii) Energy and ancillary services markets: short run resource allocation

The initial design of organized wholesale markets in the U.S. implicitly assumed that instead of "central economic dispatch" by the vertically-integrated system operator with a geographic monopoly based on the reported costs of each generator, competitive wholesale markets could be developed which replaced the vertically integrated central planner with competitive bidding by competing generators via appropriately designed auctions to define a least cost dispatch curve (from lowest to highest marginal price bid to just meet demand at each point in time) for energy supply and ancillary network support services at each point in time (day-ahead and intraday hourly auctions). Generators would make multi-unit offers to supply quantities of generation services from the generators they own, which would include constraints specific to individual generators --- e.g. start-up costs and ramping times and constraints. The system operator uses this competitive bid information in a security constrained bid-based dispatch program, which includes the transmission network topology and other network operating constraints, to solve for the least cost day-ahead dispatch to meet forecast hourly demand during each hour and the associated uniform market clearing prices at each location (locational or nodal pricing). A similar process proceeds for intra-day markets. The market clearing spot prices are directly analogous to the short run marginal cost along the dispatch curves in the old centralized economic dispatch models. Basically, these competitive market mechanisms were developed to replicate the idealized central economic dispatch process, essentially adopting the view that there is a duality between the competitive market mechanisms and this idealized central economic dispatch process.

We should recognize that in both a vertically integrated system and an organized wholesale market of the type that has developed in the U.S., the system operator always keeps physical control of the system, making dispatch decisions as much as possible by choosing the generators that have offered to supply energy and ancillary services at the lowest prices reflecting their short-run marginal costs (SRMC) consistent with maintaining the reliability requirements of the network. The reliability requirements are in turn typically defined by engineering criteria that have been carried over from the vertically-integrated utility regime. System operators have the flexibility to dispatch generators "out of merit order" if necessary to maintain reliability of the system and a variety of imperfect rules have been specified to compensate generators called out of merit order and those in merit order which, as a result, are not called to supply. If these "out-of-market" payments become significant they can lead both to short-run operating efficiencies and distort investment incentives.

One might ask why bother with the difficult process of creating wholesale electricity markets with these attributes if we are simply reproducing the central planning results for generator scheduling and dispatch? The answer is that the central planning models for vertically integrated utilities are "idealized" models that do not take into account the incentives faced by the regulated vertically integrated monopoly and how these incentives affect behavior. It is generally thought that regulated monopolies have poor incentives to control operating and construction costs, to maintain generator availability at optimal levels, to retire generators when the expected present value of their costs exceeded the expected present value of continuing operations, to overinvest in new generating capacity, to fail aggressively to seek out innovations, and other inefficiencies. In short, the real world regulated monopoly does not perform as the idealized model implies. In principle, if competitive market mechanisms are well designed and market power is absent, competing generators should have high powered incentives to control operating costs, construction costs, to maintain availability, to seek out innovations, to invest to enter the market, and to exit the market to cut expected losses. However, if there are imperfections in the market mechanisms and associated rules and market power, the market model will be characterized by imperfect performance as well. The move to liberalizing the electricity sector in this way was effectively a bet that the costs of any residual imperfections in competitive wholesale markets are smaller than the costs of imperfections associated with the behavior of vertically integrated monopolies.

These organized wholesale markets also produce transparent spot prices for energy and ancillary services. These prices provide signals to generators regarding when and where to offer to supply as well as price signals to guide entry and exit decisions. Locational prices can also be used to guide transmission investment decisions and adjustments in reliability rules and operating decisions. If these price signals are conveyed in prices charged to consumers that better match variations in marginal cost through variable retail pricing, more efficient consumption behavior will be induced (more on variable pricing below). While in theory, the central economic dispatch process produces shadow prices that are conceptually similar to spot prices, these shadow prices are not transparent. This creates challenges for using them to support pricing and investment decisions by regulators.

(iii) Entry, exit, capacity pricing and scarcity pricing: long run resource allocation

Wholesale markets in the U.S. were designed as well to support decentralized free entry (and exit) of generating capacity along with efficient dispatch, efficient pricing and reliable clearing of supply and demand. In the long run, forward wholesale price and associated profit expectations were expected to determine decentralized decisions by investors to build new generating capacity to enter the market and decisions by existing generators to exit. That is, "the market," rather than integrated resource planning by the vertically integrated utility, interest group interventions, plus regulatory oversight, would determine entry and exit decisions by decentralized owners of generating plants and lead to an efficient portfolio of generating capacity over time. Investors would bear the risks of changes in market conditions, construction cost overruns or construction efficiencies, etc., rather than consumers as was the case when all "prudent" generating costs were passed on to consumers through regulated rates. Decentralized entry of generating capacity based on market price signals, rather than regulated integrated resource planning, reflected one of the hidden goals of restructuring and reliance on competitive wholesale markets: get the interest group politics out of the regulated utility's entry, exit, and fuel supply decisions. However, this goal assumed implicitly that market mechanisms would also be introduced to deal with the most important externalities through some form of efficient emissions pricing.

In my view, the initial "centralized" wholesale market designs in the U.S. paid too little attention to their investment incentive properties. In this regard, there is one particular attribute of the fully developed Boiteux-Turvey model (See Joskow and Tirole, 2007) that was not adequately taken into account initially in many wholesale market designs and is a source of an important wholesale market imperfection.[15] This imperfection will become more and more important as intermittent renewable generation with zero marginal operating costs becomes a large portion of generation. Regulators and system operators have been chasing their tails to deal with the resulting imperfections in investment and retirement incentives. Drawing on the Boiteux-Turvey Model (and nicely explained by Dreze, 1964), in order to support an efficient long run equilibrium, prices must rise <u>above</u> the short run operating cost of the highest marginal

[15] Another "surprise' was that a voluntary long term contracting market between generators and load serving entities did not emerge. While voluntary forward markets have emerged, they offer contracts or hedges of relatively short duration (e.g up to two or three years) and are quite illiquid beyond a year or so. The reasons for this are beyond the scope of this paper, though short run prices that are too low lead to forward prices that are too low as well.

operating cost plant on the system when total available generating capacity is a binding constraint on balancing supply and demand. Prices must rise high enough under these contingencies for decentralized investors to expect that the present discounted value of future prices will be high enough to cover the capital costs as well as the operating costs of an investment in generating capacity.[16] In the standard model prices must be high enough to be expected to cover the capital costs of a peaker, the least capital intensive generating technology in the standard model. This in turn produces enough revenue to cover the capital costs of an optimal portfolio of infra-marginal generators as well (Joskow, 2008).

Whether one relies only on short run marginal cost pricing in the regulated central planning world of Boiteux-Turvey or instead designs wholesale markets so that prices cannot rise much above the short run marginal operating cost of the highest operating cost generator at the top of the bid-based dispatch curve (e.g. by imposing price caps), the fact is that these prices cannot support a long run equilibrium with an optimal configuration of generators. Boiteux (1949 and 1956), Dreze (1964), Joskow (2008)) recognize this fact, but it was given inadequate attention initially in wholesale market designs. Market design efforts focused on designing short run market mechanisms: generation and ancillary services auction design, efficient nodal price formation to reflect network congestion, multi-settlement systems, and other important "details" of market design required to operate the system efficiently and reliably under most contingencies.[17] Little attention was played to the long run incentives for exit and entry that these market design features produced.

[16] Obviously, under these conditions these prices should be conveyed to consumers and supply and demand balanced by responses on the demand side. See Joskow and Tirole (2007).

[17] Let me note that this also has implications for measuring market power. A long run competitive equilibrium can only be supported by revenues that exceed the revenues produced by short run marginal cost pricing. Accordingly, a finding that revenues exceed what would result from setting prices exactly equal to short run marginal operating cost does not necessarily imply that there is a market power problem. As a practical matter, one has to look at "uneconomic" withholding of capacity to identify market power.

Basically, if the peaking plant that is called last to meet peak demand levels can earn only its marginal operating costs, or prices are capped below the value that reflects consumer valuations of their consumption being rationed to balance supply and demand when demand exceeds generating capacity and threatens system reliability (value of lost load --- VOLL) then it cannot recover any of its investment costs. Indeed, as Joskow (2008) demonstrates with a numerical example, pure short-run marginal cost pricing plus non-price rationing when demand exceeds generating capacity does not allow any generator in the optimal configuration to fully recover its capital costs. This "revenue inadequacy" or "missing money" problem can lead to pre-mature exit of existing generating capacity as well as inadequate investment in new generating capacity.

Most wholesale markets in the U.S. have repeatedly failed this "revenue adequacy" test based on energy market revenues only over many years.[18] A significant shortfall would exist for grid-based wind and solar as well, but for various federal and state direct and indirect subsidies and "out-of-market" payments that they receive.[19] Although the "missing money" problem focuses on new investments in generating capacity, this imperfection in pricing also affects exit decisions. Existing generators incur more than marginal fuel costs. They have employees to pay, property taxes to pay, and other fixed costs associated with keeping a plant open. More importantly, as plants age there are incremental capital costs that must be incurred to sustain availability and operating efficiency. Thus, even for existing plants, the longer run avoidable costs are typically significantly higher than their avoidable fuel costs.

There are two more or less equivalent ways to reflect the value of reliability under scarcity conditions and allow generators to monetize the marginal value of more or less generating capacity when generating

[18] See for example Monitoring Analytics, 2018, pp. 309-335.
[19] Monitoring Analytics, 2018, page 324.

capacity constraints are binding. Ideally, wholesale markets would include active demand sides that reflect the price sensitivity and willingness to pay of all consumers, especially during contingencies when the system operator confronts operating reserve deficiencies and begins to implement emergency actions to avoid voltage reductions, rolling blackouts, or a system collapse (Joskow and Tirole 2007). During such situations wholesale market prices should rise above the marginal operating costs of the last generating unit to be dispatched to reflect the value that consumers place on consuming less electricity or being subjected to involuntary blackouts. We can refer to this as the value of lost load (VOLL). Estimates of the value of lost load vary widely, but are typically much higher than the marginal operating cost of the last unit to be dispatched (Schroder and Kuckshinrichs, 2015). And as prices rise, consumers should reduce consumption to bring supply and demand back into balance in the short run with prices rather than non-price rationing.

However, in the RTO/ISO markets in the U.S., prices generally do not rise to clear the market when generating capacity constraints bind because *(a)* there is typically a price cap set well below VOLL reflecting concerns about market power[20] and *(b)* there is not a fully representative price-sensitive aggregate demand function to allow price to rise to reflect the "value of lost load" (VOLL) to individual consumers plus a representation of the external cost that could lead to a network collapse affecting all consumers (Joskow and Tirole, 2007). [21] If such a demand function were properly represented in the wholesale market, prices would continue to rise to ration demand in the face of generating capacity

[20] U.S. RTO/ISO system operators have proposed and FERC has approved price caps well below VOLL. The justification is to mitigate generator market power as the system approaches capacity constraints. Even with many generation suppliers, as demand approaches capacity constraints, even a small generator can recognize that withholding a little capacity from the market can lead to a large price increase absent a price cap and an active responsive demand side represented in the wholesale market.

[21] Texas (ERCOT) is an exception. It has a $9,000/MWh price cap. However, it is not at all clear what the mechanism is that leads prices to rise to high levels reflect an efficient representation of consumer demand for energy and reliability since price sensitive consumer demand is only partially represented in the wholesale market.

constraints. This is often referred to as "scarcity pricing." These anticipated demand responses and associated market prices would also affect the optimal investment profile, with "scarcity pricing" contingencies factored into the choice of total generating capacity and the quantity of each of the generating technologies that make up the optimal portfolio of generation investments. Unfortunately, consumer demand and valuations of reliability are not and probably cannot be fully represented in wholesale market demand functions today. Perhaps the spread of smart meters and grid monitoring and control technology will ultimately allow better representation of consumer demand and associated demand response but as Joskow and Tirole (2007) point out there are also externality or common goods attributes of reliability that cannot be represented fully in the aggregation of individual consumer demand functions placed on the wholesale market.

Note that scarcity pricing is not a departure from the basic principle of short run marginal cost pricing. Rather, movements along the appropriate demand curve when capacity constraints are binding reflect consumer valuations of sudden reductions in available generating capacity (reliability) and represent consumers' short run marginal opportunity cost of having more or less generating capacity. While there may be few hours when capacity constraints are binding, energy prices would likely go to very high levels as demand is price-rationed and yield substantial revenue for all generators which would allow them to recover their capital costs in long run equilibrium (Joskow, 2008).

An alternative approach to producing the expected net revenues needed to support investment costs has been adopted in the several RTO/ISOs in the U.S. This approach is referred to as a "capacity market" mechanisms. These mechanisms require establishing a minimum generating capacity target to meet reliability constraints and running a forward market that determines "capacity prices" that generators receive if they can commit to being available to supply energy or and ancillary services under "stressed" system conditions. The creation of capacity markets recognizes that wholesale energy spot prices are capped to mitigate market power, that VOLL is not directly reflected on the demand side in organized wholesale markets, and that RTO/ISOs have retained target reserve margins for reliability from the pre-liberalization era which determine when system operators begin to take emergency actions to ensure that demand does not exceed capacity constraints requiring actions like voltage reductions and rolling blackouts. It recognizes further that some additional competitive market mechanism is needed to be adopted that reflects these considerations so that the quasi-rents that would be produced if there were efficient scarcity pricing can be produced through an alternative competitive mechanism.

The design and implementation of this "capacity market" mechanism has involved the creation of aggregate system (and local where there is persistent congestion separating portions of the RTO's control area) capacity targets, auction markets when generators can submit bids to commit to being available to supply under capacity constrained conditions, and resulting forward capacity prices (Cramton and Stoft (2006), Keppler (2017), Leautier (2016)). This mechanism requires the system operator to define a target aggregate generating capacity to meet specified reliability/reserve requirements for the system, specify a demand curve for capacity anchored at this target and set up a bid-based "capacity market" to allow existing capacity, potential new capacity, and certain demand curtailment actions, to compete in a forward market that establishes forward prices for capacity for some number of future years (e.g. three years in New England) along with performance obligations during time periods when the committed capacity may be called. The structure of these capacity markets varies from ISO to ISO and the market designs have changed over time. Typically, existing and new generation resources (as well as demand side resources, including energy efficiency, per rules established pursuant to FERC Order745[22]) compete

[22] I agree with William Hogan (2016) that the payment mechanism for demand-side resources adopted by FERC and approved by the U.S. Supreme Court is deficient and can lead to perverse results.

to be selected to meet an aggregate peak generating capacity target established by the ISO consistent with its reliability/reserve criteria.[23]

While perhaps attractive based on the standard Boiteux-Turvey theory, the capacity market designs and implementation have not been without problems in practice. Getting pay for performance (availability) incentives right has been especially problematic. Capacity market designs have gone through numerous "refinements" over time, including recent actions to create zonal capacity markets reflecting transmission congestion, adjustments in the slope, upper and lower bounds on the system capacity demand curves, treatment of demand side resources, availability/performance requirements and penalties, treatment of subsidized generation, and other changes.[24] Despite these challenges, capacity markets have now become the favored approach in the U.S. and now Canada for dealing with incentives to maintain levels of generating capacity that satisfy reliability criteria. PJM, ISO New England, and New York ISO have adopted organized wholesale markets, and Alberta, Ontario and others are now moving from energy-only markets to energy plus capacity markets as it is perceived that energy-only markets with price caps do not yield sufficient revenues economically to sustain existing capacity and to attract new generating capacity. California has a resource adequacy mechanism that appears to be evolving into and organized capacity market (more below). We should remember, however, that there is a linkage between properly designed and implemented scarcity pricing mechanisms and properly designed capacity market mechanisms.

Why have I spent so much time on scarcity pricing and capacity pricing problems and the associated efforts to solve the "missing money" problem? As I will discuss further below, the rapid growth of intermittent generation means that (putting out-of-market subsidies and payments aside) revenues from capacity

[23] An excellent description of the capacity market in New England can be found in the ISO-New England Annual Markets Report, Section 6.1, May 17, 2018.
[24] See for Example, ISO New England, May 17, 2018, page 146.

prices and/or scarcity prices will have to be a growing source of revenues to support investment and retirement decisions consistent with an efficient long run equilibrium if it is expected that we will rely on decentralized wholesale market price signals to attract an efficient generation portfolio. Very simply, as the penetration of intermittent generation with zero marginal costs grows to become a large fraction of total generation, market-based energy prices during the hours it operates will fall toward zero --- perhaps to zero in many hours if very aggressive wind and solar penetration goals are met. The energy market will produce little in the way of net energy and ancillary service market revenues to cover investment costs. If we expect to rely on the standard RTO/ISO decentralized wholesale market model, scarcity pricing and/or capacity pricing will have to be a much more important source of revenues to cover the investment costs of solar, wind, dispatchable generation for ramping and ancillary services, and storage.

(iv) Extending the Boiteux-Turvey model to incorporate intermittent generation

Recent theoretical literature has extended the traditional Boiteux-Turvey model to incorporate intermittent generation at scale (MacCormack et. al. 2010; Green and Vasilakos, 2011; Green and Leautier, 2018; Llobat and Padilla, 2018,) with interesting implications. This theoretical work indicates that the changes in the level, hourly distribution, and volatility of wholesale prices has implications for the profitability of incumbent dispatchable generating capacity, for incentives for entry of new generating capacity that is better matched to the attributes of a generating system with a large fraction of intermittent generating capacity (e.g. quick start, flexibility), and for the optimal mix of generating capacity. Let me note that most of this theoretical work takes the penetration of intermittent generation as being exogenous, driven by policy actions, and does not derives the optimal mix of solar, wind, and fossil generation, etc.

This work implies that the attributes of electricity sectors with large scale deployment of intermittent generation are not favorable to traditional base load generating and mid-merit capacity with high capital costs, high start-up costs, and limited flexibility in dispatch. As intermittent generation expands, existing dispatchable generation becomes increasing unprofitable and eventually retires (Green and Léautier 2018). There will be just too many hours with very low or negative prices and too much day-to-day price volatility for these plants to cover their going forward costs, let alone their capital costs. Simple modern combustion turbines--- that have relatively low capital costs and the flexibility to supply very short term frequency control, voltage support and balancing services, to increase output rapidly enough to meet the variable end of day ramp, are in a much better position to recover both operating and capital costs with relatively low capacity factors, assuming that wholesale prices are set right. The generating units with these flexibility attributes should be the last to find it economical to exit the market and first to enter the market. We turn next to a discussion of whether and how these effects are being realized in California.

V. Impacts of intermittent renewable energy at scale in the California ISO (CAISO)[25]

Among the wholesale electricity markets in the U.S., California is the most interesting. This is not because California has a particularly interesting market design, it does not. Rather it is because California is far ahead of the rest of the U.S. in terms of meeting goals for replacing fossil-generating capacity with intermittent wind and solar. While California is not yet close to the longer-term goal of moving to a zero carbon emissions electric power system with much great reliance on wind and solar, it is far enough down the path to a system dominated by solar (primarily) and wind, that we can begin to observe empirically some of the implications of this transformation. California is particularly interesting because the mix of solar and wind is much more like it is projected to be in the rest of the U.S. in the future, especially as

[25] This section will focus on the effects on wholesale prices, entry and exit of dispatchable generation. Energy storage and demand side responses also have the potential to respond efficiently to intermittency. I will turn to storage and demand response in the next section.

solar generation is expected to grow much more quickly than wind and other renewable generation in the future (EIA, AEO 2018, pp. 93-7). The data available for California are also much richer and more available than the data for other regions. So, California (CAISO) is a worthwhile case study.[26] Let me note, however, that the effects on wholesale markets that we are seeing in California are being seen, to a lesser extent so far, in the other organized RTO/ISO markets in the U.S. As the other regions catch up with California, in terms of the penetration of intermittent generation, the effects will be similar (LBL Report, 2018b).[27] Moreover, my reading of wholesale market reform discussions in Europe and the U.S. is that the issues associated with integrating intermittent renewable resources at scale into wholesale electricity markets are very similar.

(i) Intermittent generation supply and price patterns

The energy supplied by wind and solar generating facilities has a short run marginal cost of roughly zero once the facility has been constructed (as well as ongoing maintenance costs which are properly treated as fixed costs per year). If they were traditional dispatchable generating facilities, they would be dispatched all of the time except when they experience forced-outages or are off-line for maintenance. They would be the ultimate base-load facilities --- with even lower short run marginal generation costs than nuclear which has over a 90% capacity factor in the U.S. However, solar and wind facilities are not dispatchable in the traditional sense. Their production is driven by the availability of wind and sun at their locations. Both wind and sun resources vary significantly from hour to hour, day to day, and season to season and their supplies are characterized by significant uncertainty. As a result, the production of

[26] While this paper was being written Bushnell and Novan (2018) distributed a working paper that contains a comprehensive analysis of supply and pricing patterns affected by the penetration of wind and grid-based solar in the CAISO. I don't think that there are significant differences in our empirical conclusions.

[27] California does have access to an unusually large amount of conventional hydroelectric capacity which can be used to some extent to manage intermittency.

electricity from solar and wind facilities is highly variable, controlled by natural variations in wind and solar rather than traditional economic dispatch curves and protocols.

I now turn to exploring the extent of this variability of solar and wind generation observed in the CAISO in more detail. Figure 1 contains chart that displays the hourly production of grid-based solar energy on a hot summer day in 2018. Figure 2 contains a chart that displays the hourly grid-based solar generation in California on a winter day in 2018 with an overlay of the grid-based solar production on the hot summer day. These days were selected for illustrative purposes only. We can see not surprisingly that solar generation only takes place during daytime hours, that solar production in the winter is lower than solar production in the summer as the days are shorter and peak insolation is lower. Figure 3 adds wind generation to Figure 1. This hot summer day was a relatively low wind generation day. Figure 4 adds wind generation to Figure 2. This winter day is also a relatively low wind generation day. We can see that on these particular days, aggregate intermittent renewable generation far exceeds wind generation during the day, but wind generation is fairly steady across all hours during the day, with higher production at night than during the day in the summer. However, wind generation varies widely from day to day as we shall see.

INSERT FIGURE 1

INSERT FIGURE 2

INSERT FIGURE 3

INSERT FIGURE 4

Figures 1, 2, 3 and 4 do not include generation from BTM PV facilities ("rooftop PV" for short, though these facilities do not have to be located on roofs). Output from rooftop PV is typically not measured directly by and cannot be "seen" by the system operator. There is a measurement and ultimately operational issue here. BTM PV appears in the CAISO data only as a reduction in the demand to be served from the grid that is "seen" by the system operator. This may have been fine when generation from rooftop PV was very small, but it is now significant and expected to grow rapidly. Rooftop PV has similar effects on the system as grid-connected PV. These effects are now buried in what is generally referred to as "load" or "demand" on the grid. However, "demand" measured in this way is more properly characterized as consumption net of BTM generation. In 2017 the CAISO had about 10 GW of utility scale solar (nearly 12 GW by October 2018) and roughly 6 GW of BTM PV. Utility scale solar accounted for 11% of total CAISO delivered generation (total generation includes imports) in 2017, but has been as high as 20% on some days in the first half of 2018. Rooftop PV has a lower capacity factor than utility scale PV so 5% is a reasonable guestimate of the associated generation in 2017, and almost 10% on a recent peak solar day. Accordingly, about a third of the total solar production in California cannot be seen by the system operator.[28]

The variation in wind and solar production is not just hourly and seasonal. There is very substantial variation from day to day as well. Figure 5 displays the *daily* production from grid based solar in the CAISO between 2010 and mid-2018. There is very significant day to day variation and seasonal variation observed as well as a trend reflecting growing grid-based solar generating capacity during this time period. The unobservable generation from rooftop solar should exhibit a similar pattern, but the effects would be buried in the level and volatility of observed demand on the grid seen by the system operator since as

[28] The situation in New England is even more extreme. The ISO presently "sees" only about 100 MW of grid-connected solar. However, there is another 2,300 Mw of behind-the meter-solar or grid-connected solar that is not monitored by the ISO. See ISO New England, 2018b. The New England ISO recognizes that it needs to incorporate into its understanding of the evolution of the wholesale market the production from behind the meter solar facilities and other unmonitored solar PV generators. It has used direct measurement of generation for a sample of facilities combined with capacity and locational information from interconnection agreements to develop current estimates of generation for typical days and in its forecasts. Its forecasts indicate that the vast majority of solar capacity for the next ten years will be behind the meter or energy-only grid-connected solar that is not monitored directly by the ISO. ISO-New England, 2018a. As behind the meter solar expands it is likely that direct measurement of production from these facilities and curtailment capabilities will be necessary to manage system operations and price formation efficiently.

already noted BTM PV generation is not measured directly by the CAISO. Figure 6 contains the same data but for the more recent June 2016 to June 2018 period. The daily and seasonal variation can be seen more clearly in this figure. Figure 7 displays the daily wind generation variation for this same time period. The day to day variation for wind generation is even greater than for solar with some seasonal variation between summer (higher) and winter (lower) observed. Even over the course of a week, there is substantial day-to-day variation in generation from wind and solar. Electricity consumption also varies from day to day, hour to hour, and seasonally, though in reasonably predictable patterns.

INSERT FIGURE 5

INSERT FIGURE 6

INSERT FIGURE 7

Let us return to the summer and winter day examined earlier. Figure 8 displays the total demand on grid-based generation and the total demand less wind and grid-based solar generation, or the net demand on the grid, on this summer day. On the margin, increases and decreases in the net demand are met with dispatchable generation. More importantly, the net demand on the grid is what drives spot energy prices. This is a particularly hot summer day so that total and net demand on the grid is unusually high throughout the day. Nevertheless, we can see that the demand net of solar and wind has a local peak in the morning and is then fairly flat until 2:00 PM. It then increases over the next 8 hours by nearly 15,000 MW before beginning to decline at 8:00PM. The 15,000 MW increase in net demand on the grid reflects both rising demand during the day and the decline in solar production as the sun goes down later in the day. There is nearly a 10,000 MW ramp between 400 PM and 8;00 PM. The increasing demand on the grid after 2:00 PM is met by dispatchable generation. Figure 9 provides the same information for our winter day. This is a more typical day, but with relatively low wind generation. The net demand clearly displays the famous "duck curve" shape associated with systems with high penetrations of solar energy. Here we see both an early morning peak and an (higher) early evening peak. The demand on the grid that needs to be met with dispatchable generation declines significantly between these two local peaks reflecting the pattern of solar energy generation. There is a 10.5MW ramp between 4:00PM and 7:00 PM (3 hours), which must be satisfied with dispatchable generation and storage.[29]

INSERT FIGURE 8

INSERT FIGURE 9

As the shape and volatility of the net demand for dispatchable generation have changed, the hourly and day to day patterns of spot energy prices have also changed significantly (Bushnell and Nolan 2018; LBL 2018b). Relative spot energy prices during the day have declined and energy prices in the early evening have increased as the hourly net demand on the grid for dispatchable generation has changed. Figure 10 displays the average hourly day-ahead locational marginal spot prices (LMP) observed in the CAISO for 2010, 2015, 2016 and 2017 relative to the mean LMP for that year.[30] Dividing the average hourly spot price by the mean spot price for all hours that year is a crude way to control for the variations in natural gas prices, which drive spot energy prices during many hours over these four years. It is quite evident that as generation from solar and wind have increased over time, the hourly spot price distribution has also changed significantly, though the interesting effects are driven by the increased penetration of solar. As the penetration of solar has increased prices have declined during the day and increased during the evening ramp as solar generation fades away. In 2010, when there was much less solar and wind generation, spot energy prices were fairly flat between 8:00 AM and 8:00 PM. However, in 2017 spot

[29] California has stored hydro resources that can be dispatched to help to meet the evening peak. The California Public Utility Commission (CPUC) is now promoting battery storage. Storage will be discussed below and when I refer to "dispatchable" generation I recognize that it may include storage depending on the economics and its availability.

[30] I have not included the data for 2011, 2012, 2013, and 2014 because including the data for these years makes the chart unreadable. Including these years simply reinforces the story. Prices are adjusted for inflation.

energy prices nearly doubled an average between 3:00 PM and 7:00 PM and increased by a factor of nearly three between noon and 7:00 PM. The data for the years of 2010, 2015 and 2016 demonstrate how this pattern of relative hourly prices has evolved as solar penetration has grown. There is a very clear connection between the growth of solar generation and this distinct change in hourly price patterns.

Due to the day to day and seasonal volatility in wind and solar generation, the average hourly energy prices over the course of an "average" day do not tell the full story, however. There is significant day-to-day variability in hourly prices as well. Price volatility has increased and is expected to continue to increase as more intermittent generation is added to the system. Indeed, as intermittent generation has expanded, the number of hours with zero or negative energy prices has grown, especially during mid-day hours on weekends and other low-demand days (CAISO, June 2018, page 73).[31] The volatility of spot prices is expected to continue to increase as intermittent generating capacity expands (LBL 2018b). This is the case because as the fraction of intermittent generating capacity on the system increases, on average, the swings in aggregate intermittent generation will increase as well in response to variability of sun and wind. To balance supply and demand the system operator moves up and down the bid-based dispatch curve to dispatch more or less dispatchable generation as the swings in intermittent generation grow as a fraction of total generation. Ancillary services prices are also expected to increases as the need for short-term balancing and larger ramps increase (LBL 2018b).

INSERT FIGURE 10

[31] While the hourly distribution of CAISO energy prices has changed and will change considerably as solar and wind expand, the annual average wholesale cost per MWh, including revenues from sales of energy, ancillary services, capacity payments and other products through the CAISO, normalized for variations in gas prices, was very roughly constant between 2013 and 2018. (CAISO, June 2018, page 69). Bushnell and Novan (2018) provide a more detailed analysis.

To get a sense for the variation in hourly prices and the pattern of prices on days with different supply and demand attributes Figures 11, 12 and 13 display hourly day-ahead prices in the southern (SP15) and northern (NP15) zones of the CAISO for the hot summer day (Figure 11) and the typical winter day (Figure 12) discussed earlier. In addition, I have added Figure 13 which displays the price data for a late spring Sunday with relatively low demand but relatively high wind and solar generation. Recall that the prices displayed in Figure 11 are for a hot day in July with very high demand, good solar but low wind production. Note from Figure 11 that there is significant congestion between NP15 and P15 as the prices are significantly lower in NP15 than in SP15 during the entire day. Focusing on SP15, relatively high marginal cost fossil generation or imports are on the margin as net demand starts to rise after noon. Prices rise fairly rapidly during the afternoon and the rate of increase grows between 6:00 PM and 8:00 PM as the sun goes down. Figure 12 is a more typical winter day with relatively low wind production and fairly robust solar production that tails off starting at about 4:00 PM. There is some congestion between NP15 and SP15, though prices follow similar hourly patterns. We see that prices fall starting after 8:00 AM, following the decline in net demand, as solar production increases. Prices then increase by a factor of 2.5 between 4:00 PM and 8:00 PM before declining along with demand. Finally, Figure 13 is a late Spring Sunday with relatively low demand and high levels of wind and solar generation. There is almost no congestion, so the prices in NG15 and SP15 are close to being equal in all hours. Between 7:00 AM and 2:00 PM prices are negative or zero. Prices then rise rapidly after 2:00 PM, though solar generation peaks at 2:00 PM while wind generation increases about 25% between 3:00 PM and 8:00 PM. On all three days we observe rapidly rising and relatively high prices late in the day as solar generation fades.

INSERT FIGURE 11

INSERT FIGURE 12

INSERT FIGURE 13

These changing price patterns affect the magnitude of the net revenues that generators can to earn in the energy market. As solar generation expands the net revenues earned during the day decline and the net revenues earned during the evening ramp increase on average. In the long run this must affect the profitability of different generating technologies (entry and exit), including fast start and highly flexible gas turbines and storage supported by revenues earned by price arbitrage (buy low and sell high) that will be required to meet the evening ramp and respond to the wide variations in wind and solar production --- hourly, daily, seasonally, etc. When significant quantities of generation are partially supported by out-of-market revenues there is no reason to believe that the energy market will support an efficient equilibrium of subsidized and unsubsidized generating technologies.

(ii) Effects on exit and entry

Incumbent generators have been adversely affected by low natural gas prices, stagnant demand, and the rapid entry of wind and solar generating capacity. Stagnant demand in turn is partially affected by the growth of BTM PV installations. However, the effects of low natural gas prices per se have largely been realized while the effects on wholesale prices from secular expansion of intermittent generation will continue to intensify. On a national basis, a growing fraction of the existing fleet of nuclear plants, large coal plants, and older gas/oil steam generators already or will soon find continued operations unprofitable and have or will exit the market. In recent years most of generating capacity exiting the CAISO has been older oil/gas steam capacity originally constructed for base load and mid-merit operations, has relatively high heat rates and startup costs and can respond relatively slowly to rapid variations in dispatch needs [CAISO, 2018, page 15]. The same is true for New England (ISO New England, 2018c, page 151). Some older cogenerators and peakers have also retired in California (CPUC 2018, pages 44-46). There has been essentially no entry of dispatchable generation into the CAISO and only very small amounts of grid-based storage.

While there has been significant exit of incumbent dispatchable generators and relatively little entry of new dispatchable generating capacity across the country over the last few years, most of the RTO/ISOs in the U.S. have not yet found that the retirements leave them with too little remaining dispatchable generating to manage their systems reliably. However, pre-mature exit and inadequate entry of flexible dispatchable generation in the future is clearly of concern to system operators and regulators and they follow developments on this front closely. Resource adequacy appears to be of growing concern in California (CAISO 2018, pages 223-243). The CPUC is considering revising the short-term contracting requirements in its existing out-of-market "forward" (one year) Resource Adequacy protocols (http://www.cpuc.ca.gov/RA/) to require contracts for up to five years to ensure that retirements do not threaten reliability.[32] An incumbent generator with a flexible CCGT plant in California recently filed a complaint with FERC requesting that FERC order the CAISO to abandon its current short-term resource adequacy mechanism and adopt a centralized forward capacity mechanism such as those in New England, PJM, and New York.[33] As already noted, both Alberta and Ontario are introducing forward capacity markets and the existing RTO/ISOs are almost constantly redesigning their capacity markets to respond to accommodate intermittent generation, subsidized generation, pay-for performance criteria, and other issues. Incentive issues associated with pre-mature exit and closely related to incentive issues associated with entry of new generating capacity.

[32] Jeff Stanfield, S&P Global Intelligence, June 22, 2018, 20:53:55 GMT; "Arem Suggests 3-Year Forward RA in California," *Power Markets Today*, July 11, 2018. California does not have an organized and transparent forward capacity market like New England, New York and PJM.
[33] *Power Markets Today*, June 26, 2018

Accordingly, there is growing recognition that in the long run an energy-only market with price caps will not yield adequate revenue to deter premature exit of dispatchable generating capacity or attract efficient entry of new dispatchable generating capacity (or substitutes for it like storage) that are well matched to the operating attributes of a system with intermittent generation at scale. For example, the net revenues a hypothetical new gas turbine and a hypothetical new CCGT built in the CAISO would have earned in 2016 and 2017 do not come close to covering the capital costs (carrying charges) of a new entrant (CAISO 2018, pp. 58-65). It is also becoming clearer that capacity markets are not producing enough net revenues to deter inefficient exits and attract entry of the kinds of flexible generating capacity, and I suspect storage, needed to balance supply and demand reliably in a system with intermittent generation at scale. Relying on special reliability must run contracts (RMR) for selected generators that the system operator decides to pay is not an attractive long-term solution.

We must recognize that new-entrant solar and wind generators today confront a completely different economic regime from new-entrant dispatchable generating capacity almost everywhere. The former presently have available to them federal tax subsidies, state subsidies, renewable energy portfolio mandates, tradeable renewable energy credits, and benefit in some cases from mandated long term contracts between regulated load serving entities and solar and wind generators selected through some type of competitive procurement requirements. On the other hand, existing and new entrant dispatchable generators today must rely on day-ahead, intra-day and real time energy, ancillary service spot market revenues, plus capacity prices in markets with capacity pricing mechanisms, as counterparties generally will not enter contracts of more than two to three years. Basically, the policy of incentivizing large scale entry of intermittent solar and wind without making necessary changes in wholesale market designs to provide better incentives for entry and exit of dispatchable generation (and storage) that is well adapted to the attributes of a system with intermittent generation at scale has been made relatively easy so far by free riding on the declining existing stock of dispatchable generating capacity. It is not at all clear that with intermittent generation at scale, the "standard" RTO/ISO market design can support a long run equilibrium with the optimal quantities of intermittent and dispatchable generation.

VI. Wholesale market design challenges

Let's contemplate a hypothetical wholesale power market that is 100% solar and wind. The marginal cost of operating solar and wind is zero. Assume that it is an energy-only market (no capacity market) with a price cap set far below the VOLL. When the price cap is hit, demand is subject to non-price rationing at the default price cap which is far below VOLL. There is no fossil generation and no storage. A system with these attributes only has two states of nature (see MacCormack, et. al. 2010). One state where the price of energy is zero and the other state where it defaults to the price cap and non-price rationing takes place. This system cannot be a long run equilibrium unless the capital costs of intermittent generation are subsidized heavily outside the market or there are (too) many hours when the price cap is hit and demand is subject to non-price rationing --- more rolling blackouts. This is the case because it is only in this state where the price cap is hit that any quasi rents are generated to cover the capital costs of the intermittent generators which provide 100% of the generation by assumption. Moreover, given the variability in generation from solar and wind, and their very different generation time profiles, well more intermittent generating capacity than 100% of peak demand on the grid would have to be installed to avoid many hours of non-price demand rationing. At the same time, there would be many hours when intermittent generation would have to be constrained off as intermittent supply would exceed demand leading to over-generation. Not a pretty picture.

This thought experiment should suggest a number of things. First, a 100% intermittent generation portfolio (no dispatchable generating capacity) would be very expensive absent inexpensive storage and/or demand-side adjustments that could make up for low intermittent supply levels and/or reduce demand during states of nature when supplies from intermittent generators are low. Relying on storage and demand side responses is especially challenging because the impacts of intermittency are not just reflected in intra-day variation in solar and wind generation. Intermittency can lead to low or high production levels for multiple days and there are season effects as well. Second, if we expect to rely on today's organized U.S. wholesale markets to support (aggressive de-carbonization goals met with wind and solar then more effective scarcity pricing and/or capacity pricing mechanisms will be required to provide net revenues to deter inefficient exit and attract efficient entry.

(i) Market tools and technologies for adapting to large scale intermittent generation

As intermittent generation expands, concerns have been expressed that the almost random variability in output from intermittent generators will threaten the reliability of electric power networks whose physical infrastructure was not designed to respond to large, sudden, and only partially predictable variations in generation. The operational challenges have been recognized for years (MIT Energy Initiative, 2011) and changes in system operating protocols to adapt to intermittent generation at scale have been ongoing. [34] I think that it is fair to say that if system operators have the right tools and technologies at their disposal they can reliably manage physically a system with a high penetration of intermittent generation. These tools involve both a compatible physical infrastructure and market mechanisms needed to support investment to create this infrastructure and to respond to new operating challenges without incurring large additional costs.[35]

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[34] U.S. Energy Information Administration, 2011, https://www.eia.gov/todayinenergy/detail.php?id=670; Fares, Scientific American, March 11, 2015; https://blogs.scientificamerican.com/plugged-in/renewable-energy-intermittency-explained-challenges-solutions-and-opportunities/

[35] For a very optimistic view see Wynn 2018.

(ii) Tinkering with the existing wholesale market designs

An electric power system with large scale deployment of intermittent generation with the attributes of wind and solar discussed above will need highly flexible generating capacity (and/or storage, demand side responses --- more below) with relatively low capital costs, low start-up costs, and the ability to respond rapidly to dispatch instructions. There are a number of dimensions of flexibility. There is a need for generation that can increase or decrease production very quickly to respond to the very short term fluctuations in the output of solar and wind facilities both to supply energy to balance variable demand and to stabilize what would otherwise appear as unwanted fluctuations in frequency and voltage. Similarly, there is a need for generation (or storage) that can ramp up quickly to contribute to the large but variable ramp over three or four hours at the end of the day as the sun goes down and before demand declines later in the evening.[36] Products (and technologies) that can make up for low production levels that last for days not just respond intra-day variability as well as responses to seasonal variability will be needed. Dispatchable gas-fueled generators can provide this product easily if they have the proper incentives. But as we drive the system toward 100% renewables fossil-fueled dispatchable generation will be increasingly limited. Wholesale markets will need to adapt by creating new product categories to enable system operators to schedule, dispatch, and pay for generating capacity that meets these response needs efficiently. This likely will require expanding or revamping the current scope of ancillary service products as well. Moreover, flexible generating capacity with relatively low capital costs will be favored as dispatchable generating capacity may be called for relatively short durations when they can earn market revenues from sales of energy, absent capacity payments.

[36] Evening electricity consumption will eventually get a boost as electric vehicle ownership expands if the owners choose to charge their vehicles as night.

While this transition takes place, it will be desirable to make efficient use of the remaining existing dispatchable generating capacity. Some of this capacity has relatively high startup costs and will likely require that system operators develop products and payment mechanisms that guarantee that these generators will recover their startup costs if they must start up early in the day in order to be ready to be dispatched hours during the evening ramp or to respond to uncertainty about solar and wind production during the course a day.

As discussed above, an efficient long run equilibrium based on sales of energy at market prices cannot be achieved if wholesale markets maintain price caps that are far below VOLL without a complementary capacity adequacy and capacity market system. Capacity markets have been redesigned frequently as their imperfections have been revealed and efficient scarcity pricing will not be feasible without reforms of retail pricing. While the ongoing refinements to capacity markets have improved their performance, they too have been based on conceptual models for electric power systems which rely primarily on dispatchable generation. But, it is not at all clear how a capacity market mechanism can be implemented with intermittent generation at scale. Capacity payments are made based on performance commitments that require generators to be available to supply when the system operator determines they are needed. How would this work for intermittent generators that cannot predict whether and how much capacity will be available at a particular hour on a particular future date? If we want an efficient portfolio of intermittent and dispatchable generation, storage, etc., how do we deal with the subsidies, mandates and contract procurement preferences given to intermittent renewable generation and storage? Can different capacity prices be paid to different technologies with different subsidy and contracting mechanisms? This would conflict with FERC's historical policy of treating all supply-side and demand-side technologies equally, though allowing for differences in generator characteristics that can be applied to all technologies (e.g. start-up costs, ramp rates, availability at time of peak system need). These issues suggest to me that it will be hard to extend today's forward capacity pricing mechanisms to a world with intermittent generation at scale.

On the other hand, there may be reasons to be more hopeful, that progress can be made with expanding the use of efficient scarcity pricing mechanisms. As I will discuss presently, there are very good reasons to fully integrate retail pricing with pricing in wholesale markets, including scarcity price signals conveyed to retail consumers. The spread of smart meters makes some variation of real time retail pricing, including critical peak pricing and related variations on this theme, much more feasible than was once the case. Intermittency and volatile spot prices makes variable pricing more desirable than it is now from an efficiency perspective as well. Integrating retail pricing with wholesale market pricing will then make it easier to represent customer demand and valuations in wholesale markets, a precondition for relying on efficient scarcity pricing to produce the quasi-rent needed to pay for investment costs. This will, of course lead to perhaps many hours during the year when spot prices are very high and this will not be popular. But then there will also be many hours during the year when spot prices will be very low. Market power issues may also reemerge as a concern if price caps are removed. Nevertheless, I think that more attention needs to be directed toward developing efficient scarcity pricing mechanisms. I return to variable pricing presently.

(iii) Storage

In most systems with goals of very high penetration of intermittent renewable generation,[37] both grid-based and importantly customer-based storage are now expected to play a significant role in these systems (Imelda *et. al.*, 2018). This should not be surprising as very high solar and wind penetration goals

[37] If the goal is 100% renewables, as a practical matter dispatchable storage must play a large role in balancing the system.

(e.g. as part of an 80% to 90% renewables goal) are not consistent with retaining significant dispatchable fossil generation to manage intermittency. With neither dispatchable fossil generation nor storage it impossible to balance supply and demand reliably with intermittent generation alone. Given the large fluctuations in day to day production from intermittent generation, sequential days of very low or very high production from intermittent generators, and the seasonal variations in production by these generators, longer term as well as short-term storage options would appear to be targets of opportunity for systems with very high penetrations of intermittent generation.

Many U.S. states and ISO/RTOs have started pilot projects to examine how storage can be integrated effectively into the grid to provide a variety of services. The Department of Energy has also supported storage R&D projects. A few U.S. states have specified mandates and established storage expansion goals (GAO 2018, pages 36-40). There are many different storage technologies with different operating attributes, current and expected future costs and historical operating experience being deployed or in development today.[38] While storage costs have fallen in the last decade (Schmidt *et. al.* 2017), they remain high compared to modern simple-cycle gas turbines providing similar services.[39] However, the combination of significant R&D, manufacturing, and installation experience, mandated long-term contracts with distribution utilities, costs are likely to fall further (McKinsey & Company, 2018).

As of March 2018, the U.S. had about 25 GW of grid-based storage.[40] However, about 95 % of the existing storage capacity is conventional hydroelectric pumped storage. The rest is divided between batteries (733

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[38] https://www.eia.gov/todayinenergy/detail.php?id=4310; GAO 2018.

[39] Of course, this comparative cost analysis may not matter if the mandate is for 100% renewables.

[40] (https://www.epa.gov/energy/electricity-storage#storage. The U.S. also has about 80GW of conventional hydroelectric capacity. Most of this capacity is potential energy storage capacity. While there is no expectation that conventional hydroelectric capacity will increase significantly in the future, this capacity can be used differently from the way it has been used in the past and help to manage intermittency.

Mw), thermal storage (669 Mw), compressed air, (114 Mw), and flywheels (58 Mw). About 75 % of the storage under development is also pumped storage, with batteries accounting for most of the rest (GAO, 2018, page 10). While a lot of popular discussion has focused on lithium-ion batteries because of their use in electric vehicles, e.g. the Tesla Power-Wall for customer use, and the 100 MW/126MWh Tesla battery installed in South Australia, there are many different types of batteries with different chemistries and operating characteristics that may be promising. Most are experimental at this point and wide-scale deployment faces economic challenges and uncertainties (GAO, 2018, pages 21-28), though the costs of some battery storage technologies are falling rapidly (McKinsey & Company, 2018). BTM storage, typically integrated with a BTM PV system today is relatively small, less than 5,000 MW nationally at the end of 2017, but growing rapidly (Smart Electric Power Alliance 2018a).

Economists tend to think of energy storage as a type of generating plant that buys energy when prices are low and then sells it when prices are high, effectively moving electricity generated in one period to a later period of time. For example, an energy storage device in California could buy power during the day when prices are low (see Figure 10), store the energy, and then sell it during the evening ramp when prices are high. Or in regions where there is a lot of wind generation at night when demand is low and prices are zero or negative, the storage device could buy power at night and sell it during the day to provide energy, ancillary services, and capacity (See Figure 12). This is exactly how conventional pumped storage is often used, though pumped storage utilization has become more sophisticated with the development of competitive wholesale markets and provides various ancillary services and capacity (Brattle Group, 2018). Depending on the technology, this price arbitrage process can take place several times during a day, release energy for short or long periods of time, or store energy for multiple days and release it gradually when prices are highest. In the "energy arbitrage" scenario, the capital and operating costs of the storage devices are then recovered through the net revenues produced by the low/high price spreads. An efficient scarcity pricing mechanism is also likely to be better matched to storage that earns revenues from price arbitrage opportunities than would be a capacity pricing mechanism. The ultimate questions though are whether revenues from price arbitrage can support investment in storage at scale and whether storage is more economical than quick-start flexible combustion turbines that use natural gas.

In practice, energy storage is more complicated than simply taking advantage of price variability and associated price arbitrage and associated time shifting of supply in the energy market. This is the case because storage can provide multiple services (GAO, 2018, pages 16-21). In addition to responding to opportunities to move energy from one period to another stimulated by price arbitrage opportunities, storage can provide peaking capacity to meet reliability standards, frequency regulation and other ancillary services, defer transmission and distribution network investments, provide emergency backup power, and other services. Thus, there are multiple potential revenue streams and it is the sum of these revenue streams that will determine whether or not specific storage devices are profitable. Most of the ex ante simulations and historical case studies of pilot projects that have been completed indicate that the net revenues from energy price arbitrage are today a relatively small fraction of the revenues/benefits produced by these projects and that net revenues earned from sales of energy, capacity, and ancillary services based on price arbitrage opportunities have not been sufficient on their own to attract investment (Pacific Power, 2018, Sindhu *et. al.*, 2018).[41]

[41] Of course, energy price arbitrage could generate more revenues to cover capital and operating costs as the stock of intermittent generation expands significantly. Focusing only on solar as an example, as solar capacity grows, wholesale prices during the day will fall. Prices during the early evening ramp should also rise as unprofitable fossil generation exits. How high prices will be allowed to rise will depend on the evolution of capacity markets and scarcity pricing. And the size of the associated price spread in the $64,000 question regarding the ability of the basic ISO/RTO market design to support efficient investment in storage.

The hybrid nature of storage services[42] raises questions about the economic and regulatory model that will govern the entry of storage into the system. While there may be traditional market entry of storage based on price arbitrage opportunities alone in the future, reflecting similar economic considerations as the competitive entry of generating capacity (energy sales and capacity prices), transmission and distribution deferral benefits complicate things as transmission and distribution deferral opportunities are typically location specific and until recently undertaken by the transmission or distribution grid owner as a regulated investment. FERC Order 1000 has required RTO/ISOs to use a competitive bidding process for certain transmission investments, though the experience is still limited (FERC, 2017).

One approach to recognizing the multiple revenue streams associated with projects that are anticipated to be a mix of traditionally competitive services (energy, capacity, ancillary services) and traditionally regulated grid deferral and other especially distribution grid-based services which are also location specific, is a hybrid model for these projects which mixes "competition for the market" with "competition in the market." Very simply, as a response to the open transmission planning process required by FERC Order 1000, the RTO/ISOs would either identify a transmission network "problem" that needs to be resolved or identify specific grid enhancement projects, including its view on storage options.[43] The system operator would then conduct an auction for grid investment deferral alternatives (which could be storage, generation, demand-side actions) and choose the least cost options that can defer the grid investment at a cost lower than the base case grid investment. A winning storage bidder would likely also

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[42] Hybrid in the sense that storage can supply both competitive energy and ancillary market services and regulated distribution and transmission services.

[43] According to FERC staff (2017), RTO/ISO have adopted two general models to meet Order 1000's open planning and competitive procurement requirements. One model is called the "sponsored model." Under this model the RTO/ISO's open planning process results in a set of specific proposed projects. Incumbent and non-incumbent transmission developers then compete to be selected to develop these projects. The second model is call the "competitive procurement" model. Here, the RTO/ISO identifies transmission upgrade "needs." Incumbent and non-incumbent transmission developers then compete to provide solutions to these needs. See FERC (2017).

make sales of energy, capacity, and ancillary services in the wholesale market and would reflect the present value of these revenues in its bid. FERC Order 1000 effectively requires this type of planning and competitive procurement approach for transmission network investments that seek to recover revenues through RTO/ISO regional cost allocation. This approach would also be compatible with the increasing reliance on mandates, long-term contracts, and competitive procurement by load serving entities for wind and solar. One potentially controversial detail will be whether or not the grid owner can participate in the auction for deferral investments in storage.

Federal and state regulators have begun to work diligently to develop market and regulatory protocols to remove market barriers to the entry of storage. In February 2018 FERC issued a final rule (Order 841) requiring RTO/ISOs to develop rules that remove barriers to the economical entry of storage facilities into their markets.[44] There are many questions that need to be addressed, from interconnection rules, to the terms and conditions of participation in energy and ancillary services markets, to the treatment of storage as a capacity resource eligible for capacity payments. State regulators, the Department of Energy, and the RTO/ISOs have also adopted a number of policies, pilot programs, and mandates to facilitate the entry of more storage capacity (GAO 2018, pages 26-33; NC Clean Energy Center 2018, pages 11-13). Many of these projects rely on procurement through competitive bidding to win long term purchase power agreements (PPAs) designed for storage whose costs are included in regulated transmission and distribution (T&D) rates.[45] Or new storage facilities may be owned by the local T&D utility, included in its rate base and passed on to customers through regulated rates. All things considered, storage represents

[44] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* 18 CFR 35, Federal Register, 83 (44), March 6, 2018, effective June 4, 2018.
[45] For example, on June 29, 2018 Vistra Energy announced that it had entered into a 20-year contract with PG&E for a 300MW/1200 MWh (4-hour) battery storage project subject to the approval of the CPUC. https://investor.vistraenergy.com/investor-relations/news/press-release-details/2018/Vistra-Energy-to-Develop-300-Megawatt-Battery-Storage-Project-in-California/default.aspx

a promising response to intermittency and its market impacts, but in the end its viability will depend on the cost of storage and the revenues that storage can generate from wholesale markets.

(iv) Dynamic pricing and an active demand side

Finally, I want to turn to the demand side. At least in theory conveying real time wholesale price signals to retail customers would be efficient in the long run (Borenstein 2005). Despite the spread of smart meters, most residential and commercial customers are still charged for electricity based on per KWh rates that do not vary from one hour to the next. In short, they are disconnected from price variations in the wholesale markets. As a result, retail customers have poor incentives to take efficient demand side actions reflecting the changing distribution of spot prices and the increased volatility in these prices. Let me offer two prominent examples of the costs of this failure to connect retail prices with wholesale prices. There are significant potential storage opportunities at the (retail) customer level. These include battery storage, storage cooling, and storage water heating (Imelda *et. al*, 2018), in addition to increased opportunities to time shift the use of traditional appliances especially as smart internet enabled appliances become more common. With flat Kwh retail rates and net metering there is no incentive to seek out these opportunities, even though the daily pattern of spot wholesale prices and the volatility in these prices, (and associated short run marginal costs), may make such price responsive actions efficient responses to the effects of intermittent generation on wholesale price levels.

Indeed, the price variations created by intermittent generation at scale significantly increases the welfare gains from dynamic pricing compared to flat per Kwh rates. The simulation results report by Imelda *et. al.* (2018) for a 100% renewable (mostly intermittent generation) system in Hawaii are instructive. They find, that dynamic pricing yields only a modest gain in fossil-fuel dominated power systems --- 2.4% to 4.6% of expenditures. However, in a system that is heavily dependent on intermittent renewable generation, the savings from dynamic pricing increase significantly --- an 8.5% to 24.3% welfare gain. This makes intuitive sense. In a system where the short run marginal cost of generation fluctuates a lot from hour to hour and day to day, the welfare cost of flat per Kwh rates is much higher than in a system where the short run marginal cost of production does not vary very much. This is the case because with flat retail prices the average gap between retail price and marginal generation cost is much larger in a system with widely time-varying short run marginal costs than in a system where short run marginal costs do not vary very much. In their analysis, Imelda *et. al.* (2018) find that the demand-side responses induced by variable prices reflecting intermittency and associated variations in spot prices and short run marginal costs significantly reduces the costs of meeting a 100% renewables goal. Of course, the benefits depend heavily on the assumptions about consumers' demand elasticities and more generally, their attention to and responsiveness to variable pricing.

A second example is the positioning of rooftop PV systems. We have seen above (consider the pattern of hourly wholesale prices for 2017 displayed in Figure 10), that on average the diffusion of grid-based solar reduces net demand on grid-based dispatchable resources during the day when the sun shines leading to lower spot energy prices during the day. As the day proceeds after peak insolation, the sun moves West and solar production declines until the sun sets and solar production drops to zero. Toward the end of the day as the sunshine fades, the net demand for dispatchable generation increases sharply and spot prices increase as well. Some utility scale solar farms install tracking equipment that allows the solar panels to move from East to West during the day to produce more electricity later in the day when prices are high. Extending generation to later in the day thus increases their revenues. However, the equipment that allows large solar farms to move the direction toward which the solar panels point over the course of a day and from season to season is expensive and incurs high maintenance costs. It is too expensive for a typical rooftop PV system, so these systems must be oriented in a fixed direction. Without variable retail pricing that reflects the higher value of energy late in the day as the sun fades, rooftop PV facilities will be positioned to maximize total generation rather than to maximize the social value, potentially more profitable generation, since the benefit to them is driven by a flat per Kwh rate rather than the prospect of increasing revenues by producing more when prices are high. As a result, rooftop PV facilities usually point straight south if the contours of the roof make this possible. However, if the rooftop PV facilities were positioned to point further West they would produce more later in the day when prices are higher but produce less in total during the day (see Brown and O'Sullivan 2018 for a detailed analysis.) With dynamic pricing that reflects wholesale price levels they would have an incentive to reorient their PV facilities further to the West to capture the higher prices, reduce the end-of-day ramp and lead to lower equilibrium prices as the sun fades.[46]

I recognize that the responsiveness of retail consumers to variable pricing in particular and marginal rather than average prices in general has been questioned (Ito, 2014). However, I think that the bulk of the evidence drawn from variable pricing experiments, including critical peak pricing and other variations on the real time pricing theme, supports the view that consumers are responsive to price variations (Alcott 2011; Wolak 2011, 2018b; Faruqui 2016; Anderson *et. al.* 2017). Of course, the responsiveness observed varies from study to study and may not be as large as is expected. However, this is not surprising. The experiments have different designs, different levels of price variability, different durations, and different promotion and customer education components. On balance, I believe that these experiments underestimate long run consumer responsiveness. This is the case because *(a)* consumers will not invest in appliances and equipment that will allow them more easily to respond to dynamic prices if the dynamic

[46] We don't have to wait for real time pricing to improve incentives to install PV facilities that point further west. The BTM subsidy structure could give higher subsidies for BTM facilities that choose a more efficient orientation. Or a simple time of day pricing mechanism that has higher prices during say the 3PM to 9PM period would provide better incentives.

pricing mechanism they are given is only temporary, *(b)* smart appliances, equipment and control mechanisms are still at an early stage of development and diffusion, *(c)* energy service companies and equipment suppliers do not have incentives to invest heavily in marketing and promotion if the experiment is temporary, and *(d)* the experiments do not take advantage of the potential power of retail competition and the demand response services that they can provide. I do not anticipate that consumers will sit around watching their meters and turn their heating, ventilating, and air conditioning (HVAC) equipment on and off in response to dynamic prices. I do expect that, for example, rooftop PV installers will orient facilities to take better advantage of higher evening prices. I also expect that competitive retail suppliers will begin to offer demand management products in response to variable pricing that trade the right to partially control the customer's consumption during high price hours for a more stable partially hedged retail price structure provided to these customers. The retailer now takes on the bulk of the dynamic price risk in return for rights to partially control their customer's consumption when prices are high. The demand-side bidding programs that RTO/ISOs now have are compatible with this vision. And some utilities have had air-conditioner and water heater cycling programs for many years. The customer agrees to allow the utility to cycle her air conditioner a maximum number of times during scarcity conditions and gets a discount for doing so. These programs are popular. About 4 million customers are enrolled in air conditional switch programs, 1.2 million customers in water heater switch programs, and nearly 1.4 million in thermostat control programs. These programs are taking advantage of smart meters and remote-control capabilities made possible by internet enabled thermostats and appliances. Participation in these programs is growing. While much attention has focused on price responsiveness by residential customers, we should not forget that commercial and industrial consumers account for about 65% of consumption. (Smart Electric Power Alliance, 2018b). Variable pricing will give competitive retail supply companies the incentives to offer services of this type.

It is clear to me that one of the challenges for markets with very high penetration of intermittent generation is to better integrate the demand side with spot wholesale market pricing through the introduction of real time pricing (variable pricing) and related demand control mechanisms.

(iv) Partial re-integration through government mandates, competitive procurement and long-term Contracts

Tinkering with existing wholesale market designs in these ways may not, in the end, be a successful program for efficiently integrating intermittent renewable energy at scale into the system. We need to recognize that the attributes of the electricity market liberalization initiatives that have taken place in the last 25 years or so are being threatened, not by the entry of intermittent generation at scale per se, but rather by the public policies that are trying to force systems to have very high penetrations of intermittent renewable energy whether or not this is economical based on market prices. Subsidies for renewables, renewable energy mandates and portfolio standards, mandates that require retail suppliers to enter into long term contracts with renewable suppliers through competitive procurement, etc., have replaced the decentralized market incentives for entry and exit upon which the restructuring and wholesale market designs developed over the last 20 years have been based.

Of course, I recognize why policymakers may turn to generation portfolio standards, subsidies and long term contracting obligations. They want to decarbonize the electric power sector as part of a program to mitigate carbon emissions in response to climate change. First best instruments, like emissions pricing, with prices set at appropriate levels, are not available. If they were available many policymakers would probably be reluctant to rely on them fully anyway. However, the subsidies, mandates, and selective long-term contracts have implications for the design and performance of long term contracts and these consequences need to be recognized and adaptations made to accommodate them.

Is it reasonable to expect that we can rely on the one hand on central planning for renewables, and associated mandates, subsidies, long-term contracting with load-serving entities and on the other hand on enhancements to the existing energy, ancillary services, capacity market, and perhaps expanded scarcity pricing to govern operations, entry, and exit for the "residual" market? Can this bifurcated approach to wholesale markets be successful in retaining and attracting the kind of flexible dispatchable generation and storage needed to manage a system with a high level of intermittent generation efficiently? If the result is that exit of existing dispatchable generation and limited entry of new flexible dispatchable generation and storage with equivalent capabilities leads to operating problems or large number of hours where non-price (or very high price) rationing are required to maintain reliability, there will be pressure to introduce mandates for the procurement of dispatchable generation and storage as well.

Accordingly, I can see the present system changing in a way that separates investment/procurement of new generation and storage facilities of all kinds and retention of incumbent generators deemed essential to manage intermittency, from the short-term markets that "dispatch" these facilities economically. For example, the regulator might adopt a goal of having a system that is 80% renewable and a "residual" mix of dispatchable generation and storage that planners determine efficiently manages the resulting intermittency. The regulator could then force the regulated T&D owners to obey the policy by ordering regulated retail suppliers and grid owners to enter into long term contracts to attract new generating and storage facilities to match the 80% renewable goal, as well as the residual dispatchable and storage facilities needed to meet system reliability criteria, by using some type of competitive long-term PPA based procurement mechanisms. The wholesale market as we now know it would then only be a short-term energy dispatch and balancing market that would try to produce efficient spot prices but would not be relied upon to provide all of the incentives for investment or retention of dispatchable generating and storage facilities. Any net revenues potential new generators expect to earn in the energy and ancillary services market would be reflected in bids made into the long-term procurement auction. We may be well down the path in this transition to a very different kind of wholesale market structure. In Europe, there appears to be a much clear recognition that wholesale markets for long term procurement and short-term operations have become separated, that this needs to be recognized, and that more efficient wholesale market designs for both market segments should be pursued (Grubb and Newbery, 2018; Newbery *et. al.*, 2018).

VII. Conclusions

Policies aimed at rapid de-carbonization of the electricity sector by aggressively expanding the penetration of wind and solar generation have significant implications for the performance of wholesale electricity markets. The combination of intermittency, near zero marginal operating costs, imperfections in capacity and scarcity pricing mechanisms, and the reliance on out-of-market revenues to provide financial support to wind and solar generation, raise important questions about the continued reliance on market incentives to support efficient operations and to provide adequate revenue support to retain existing generators that are needed to balance the system, to attract entry of new flexible generators and storage. I do not believe that "fiddling" with existing market designs will deal adequately with all of these challenges. I do believe that market design reforms can work to align incentives with operating challenges. The development of new products that better reflect operating needs with intermittent generation at scale is an important goal. So too is better linkage of spot prices in the wholesale market with retail prices seen by end-use customers. However, I am not optimistic about the prospects for reforming capacity pricing and scarcity pricing mechanisms with minor modification to existing mechanisms. The continued reliance on subsidies, resource mandates, mandated long term contracts, etc. for intermittent generation is simply incompatible with relying on markets for the rest of the supply portfolio. The mandates, subsidies and contracting obligations will just spread as the market fails to deliver adequate retention and entry of generating capacity and storage needed to manage intermittency. We might as well face this sooner rather than later. This requires developing a separate market for long term contracts that is compatible with attracting investment consistent with the integrated resource portfolios that are increasingly being defined by government policy makers rather than market incentives. Once in the market, these resources would operate based on market incentives in reformed hourly and real time energy and ancillary services markets

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TABLE 1
U.S. Solar and Wind Generation
GWh

	Grid Solar	Rooftop Solar	Total Solar	Grid Wind	Total Grid wind+Solar	Total Grid Generation	Grid Generation Plus Rooftop PV	Wind + Solar % of Total
2010	1,212.00	2,329.00	3,541.00	94,692.00	98,233.00	4,125,060.00	4,127,389.00	2.4%
2011	1,818.00	3,692.00	5,510.00	120,177.00	125,687.00	4,100,141.00	4,103,833.00	3.1%
2012	4,327.00	5,927.00	10,254.00	140,822.00	151,076.00	4,047,765.00	4,053,692.00	3.7%
2013	9,036.00	8,131.00	17,167.00	167,840.00	185,007.00	4,065,964.00	4,074,095.00	4.5%
2014	17,691.00	11,233.00	28,924.00	181,655.00	210,579.00	4,093,606.00	4,104,839.00	5.1%
2015	24,893.00	14,139.00	39,032.00	190,719.00	229,751.00	4,077,601.00	4,091,740.00	5.6%
2016	36,054.00	18,812.00	54,866.00	226,993.00	281,859.00	4,076,675.00	4,095,487.00	6.9%
2017	52,958.00	24,139.00	77,097.00	254,254.00	331,351.00	4,014,804.00	4,038,943.00	8.2%

Source: U.S. Energy Information Agency, *Monthly Energy Review* , various years.
https://www.eia.gov/totalenergy/data/monthly/

FIGURE 1
CAISO GRID BASED SOLAR GENERATION (PV + THERMAL)
July 18, 2018

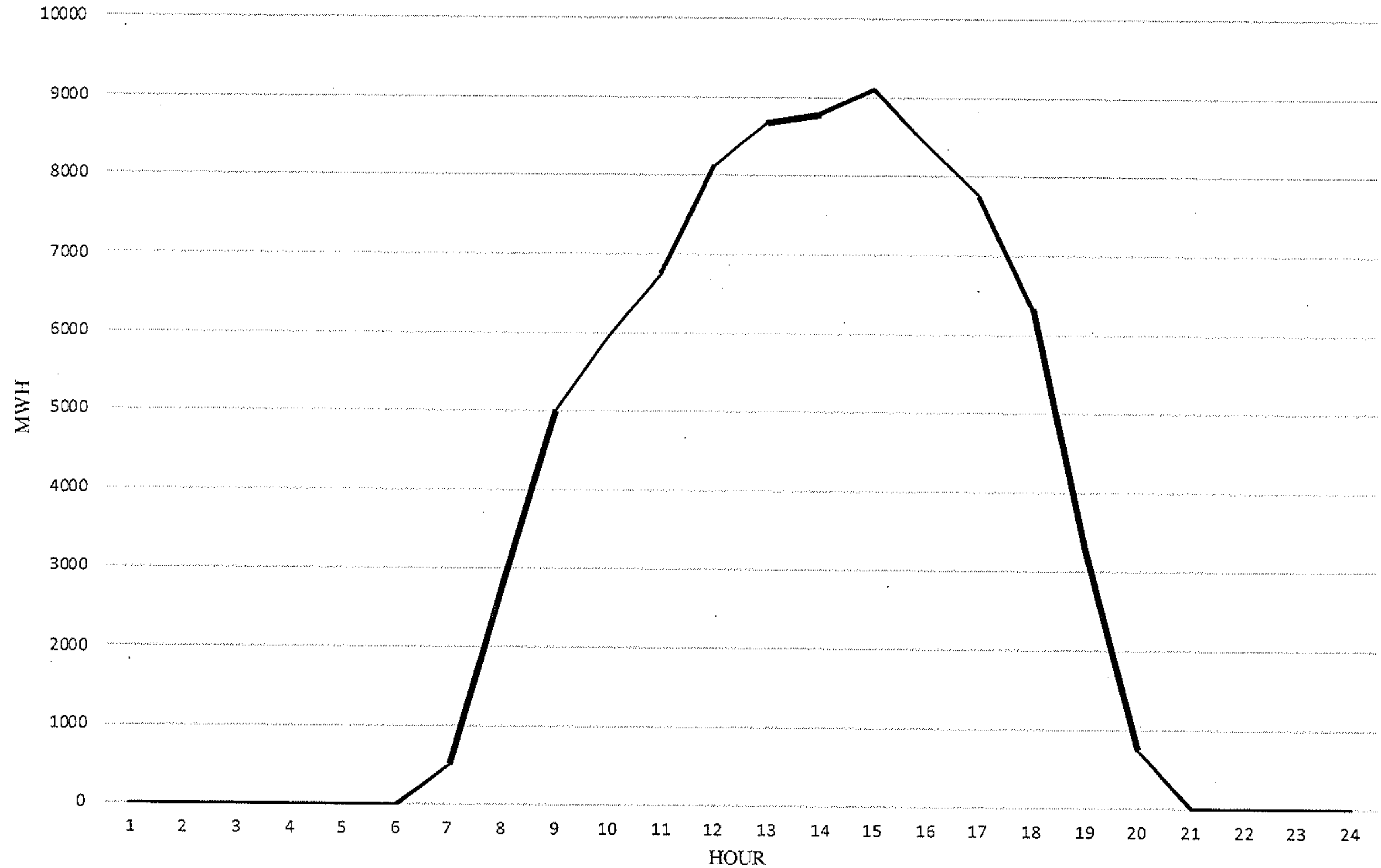


FIGURE 2
CAISO GRID-BASED SOLAR
JULY 18 AND FEBRUARY 7, 2018

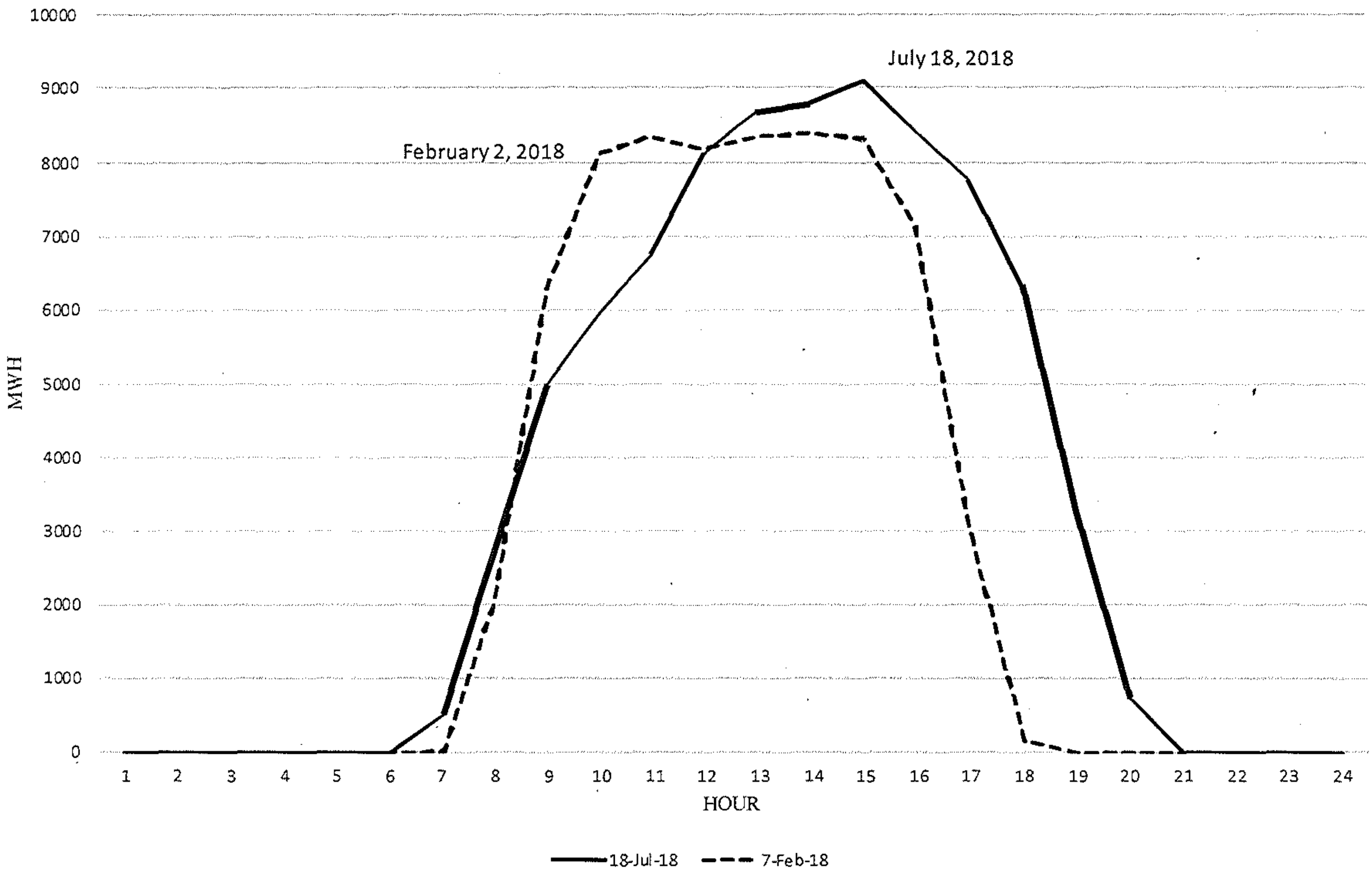


FIGURE 3
CAISO GRID-BASED SOLAR AND WIND
July 18, 2018

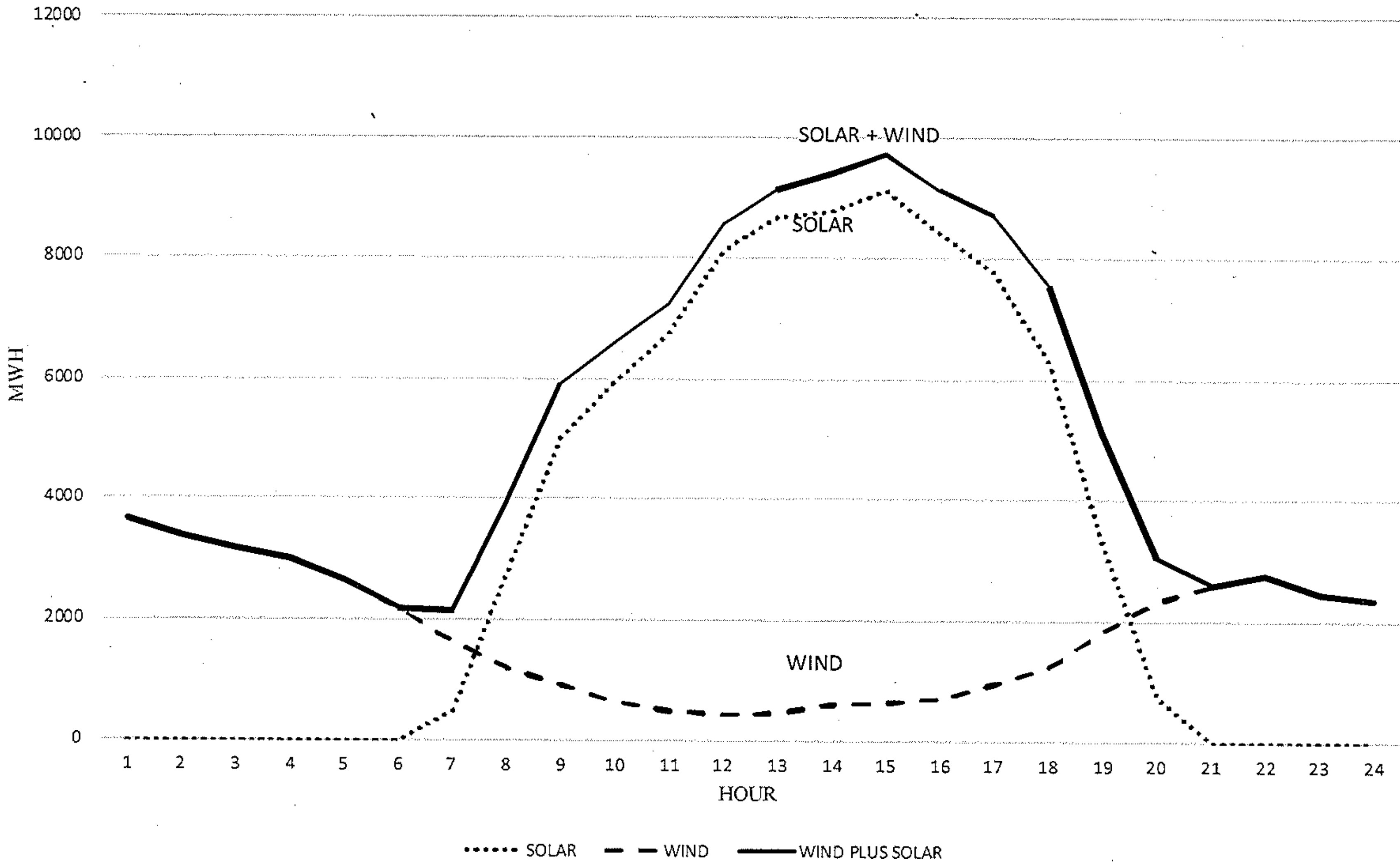


FIGURE 4
CAISO SOLAR PLUS WIND GENERATION
February 7, 2014

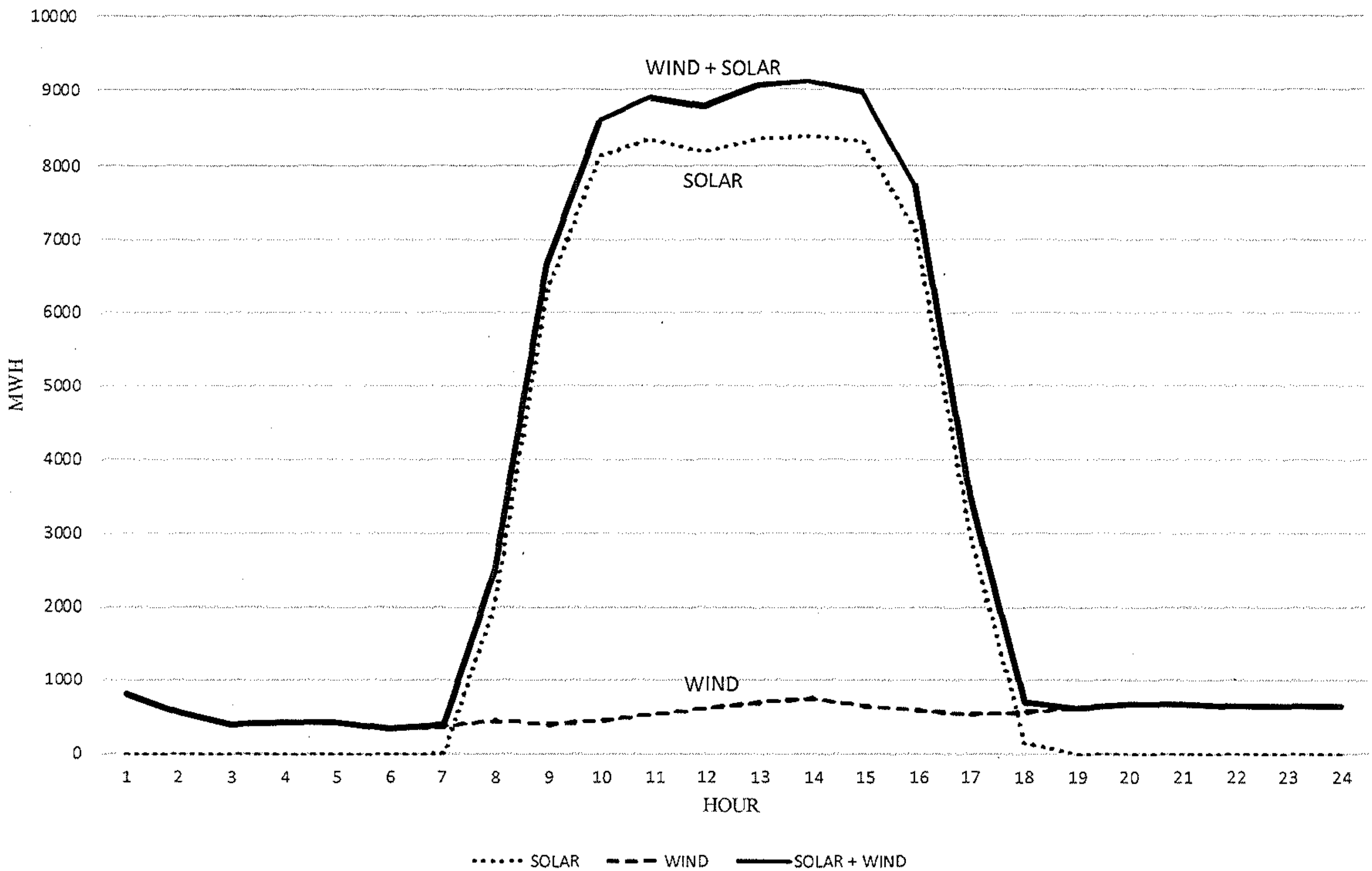


FIGURE 5
CAISO Daily Grid Solar PV
2010-2018

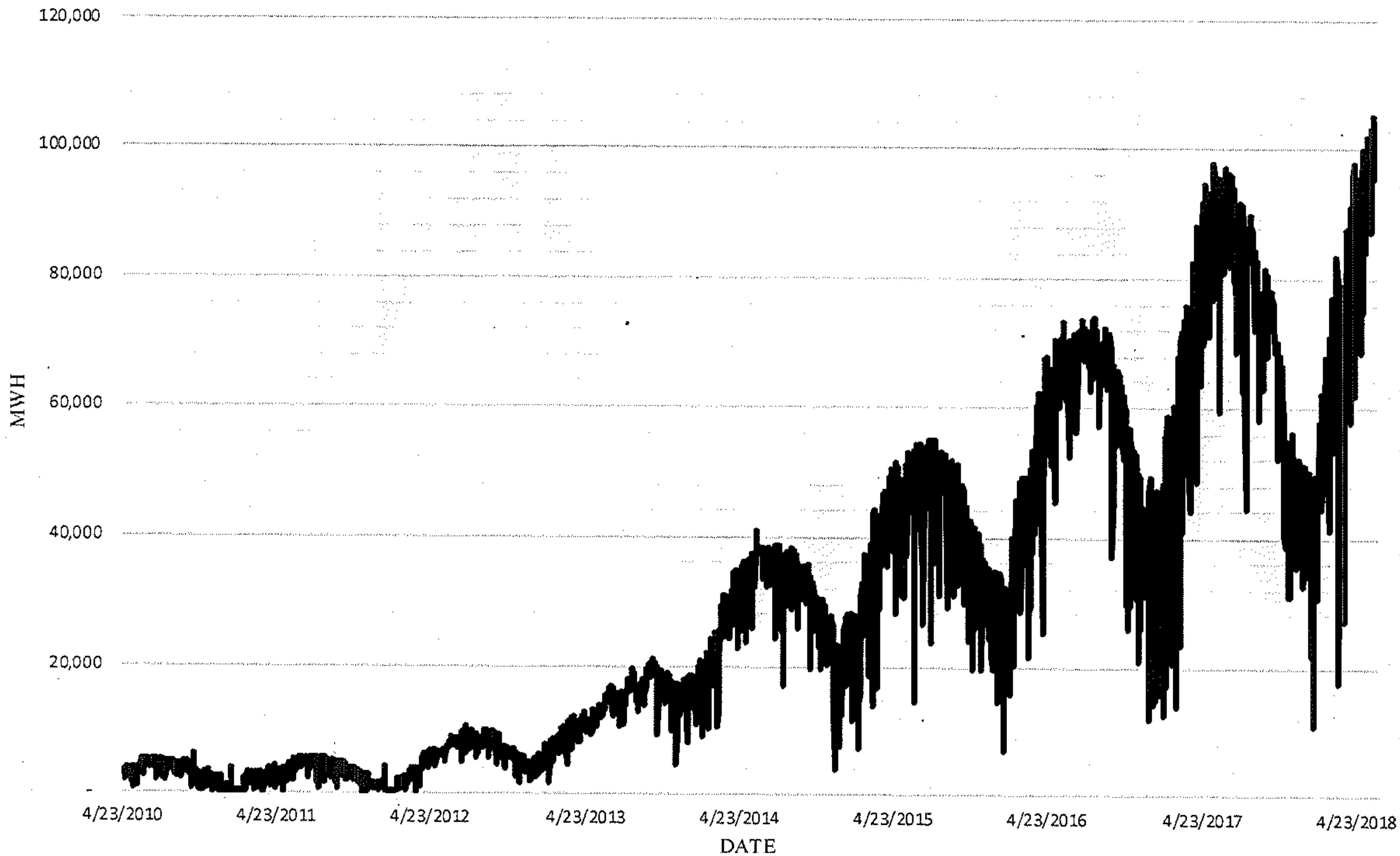


FIGURE 6
Daily Grid PV + Thermal Solar
CAISO June 10,2016-June 10, 2018

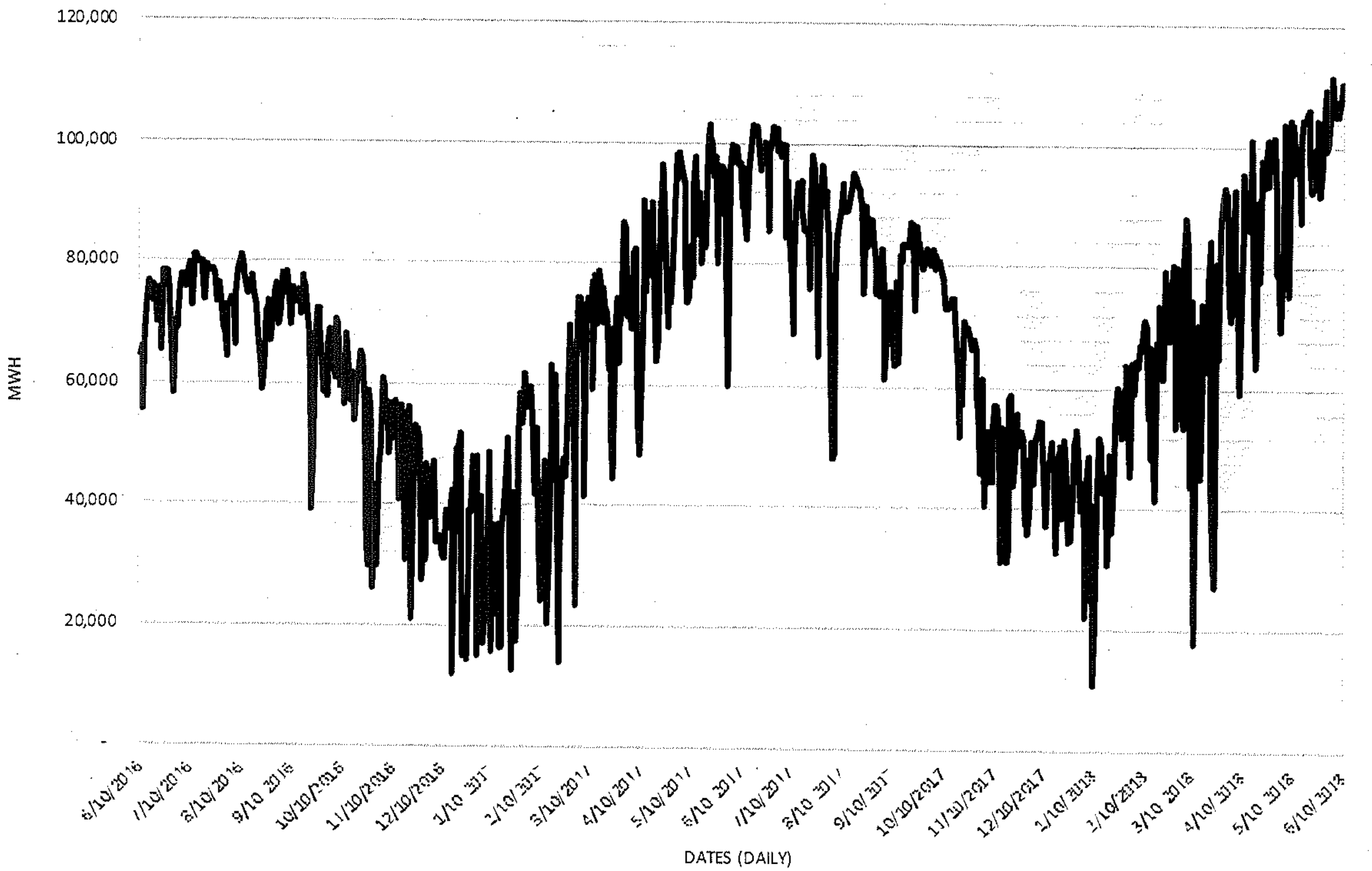


FIGURE 7
CAISO DAILY WIND GENERATION
June 10, 2016-June 10,2018

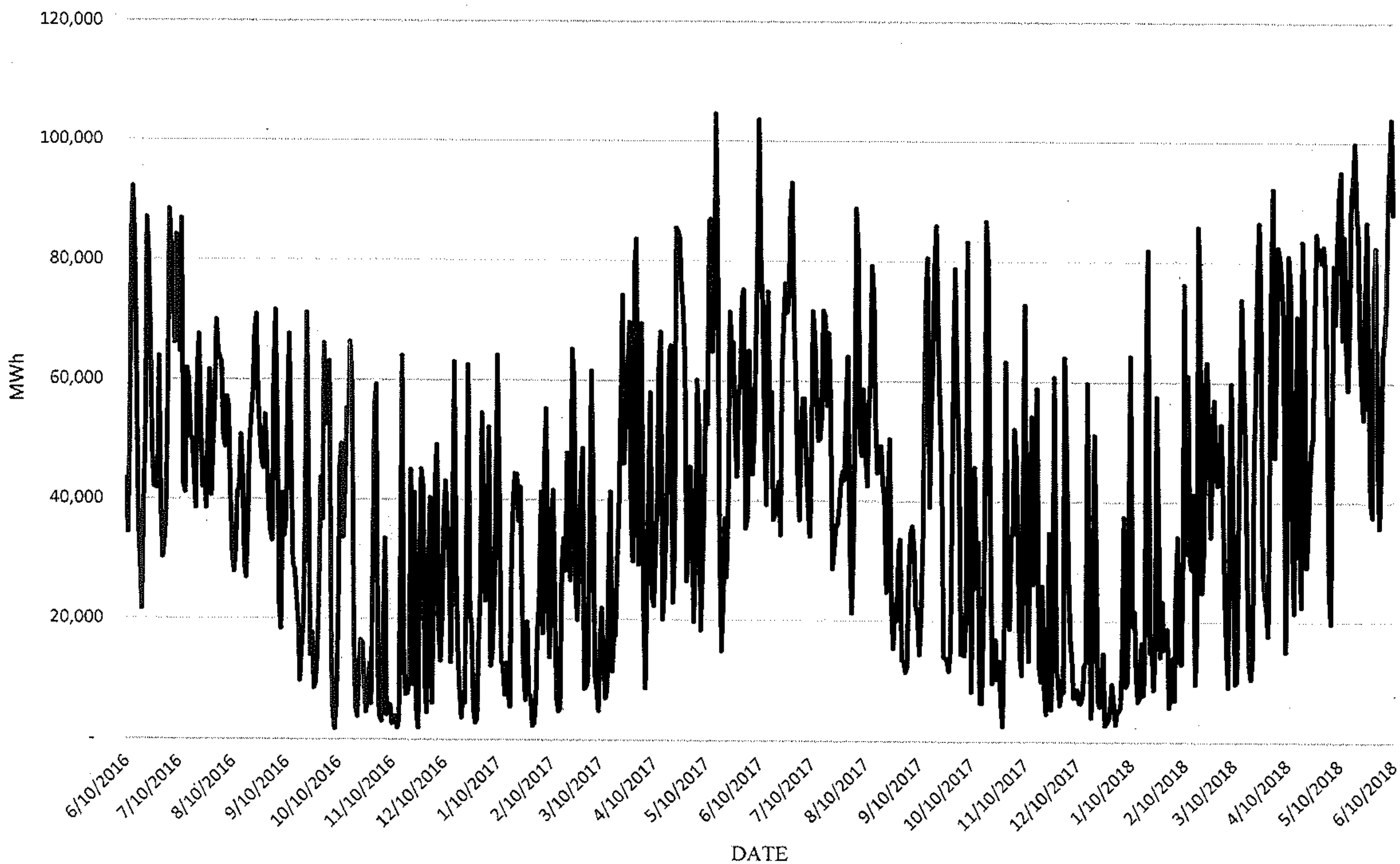
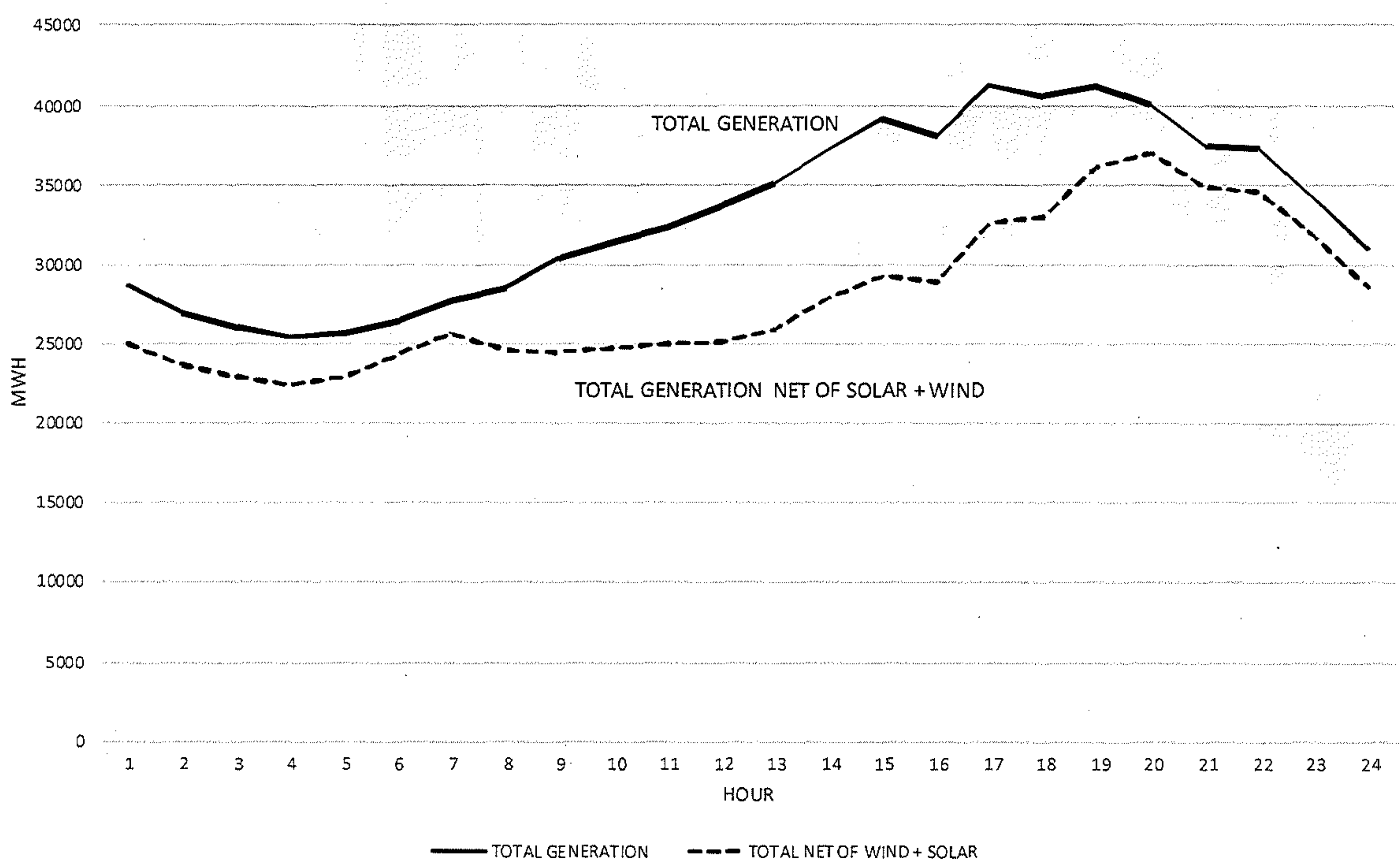


FIGURE 8
CAISO TOTAL AND NET GRID GENERATION
July 18, 2018



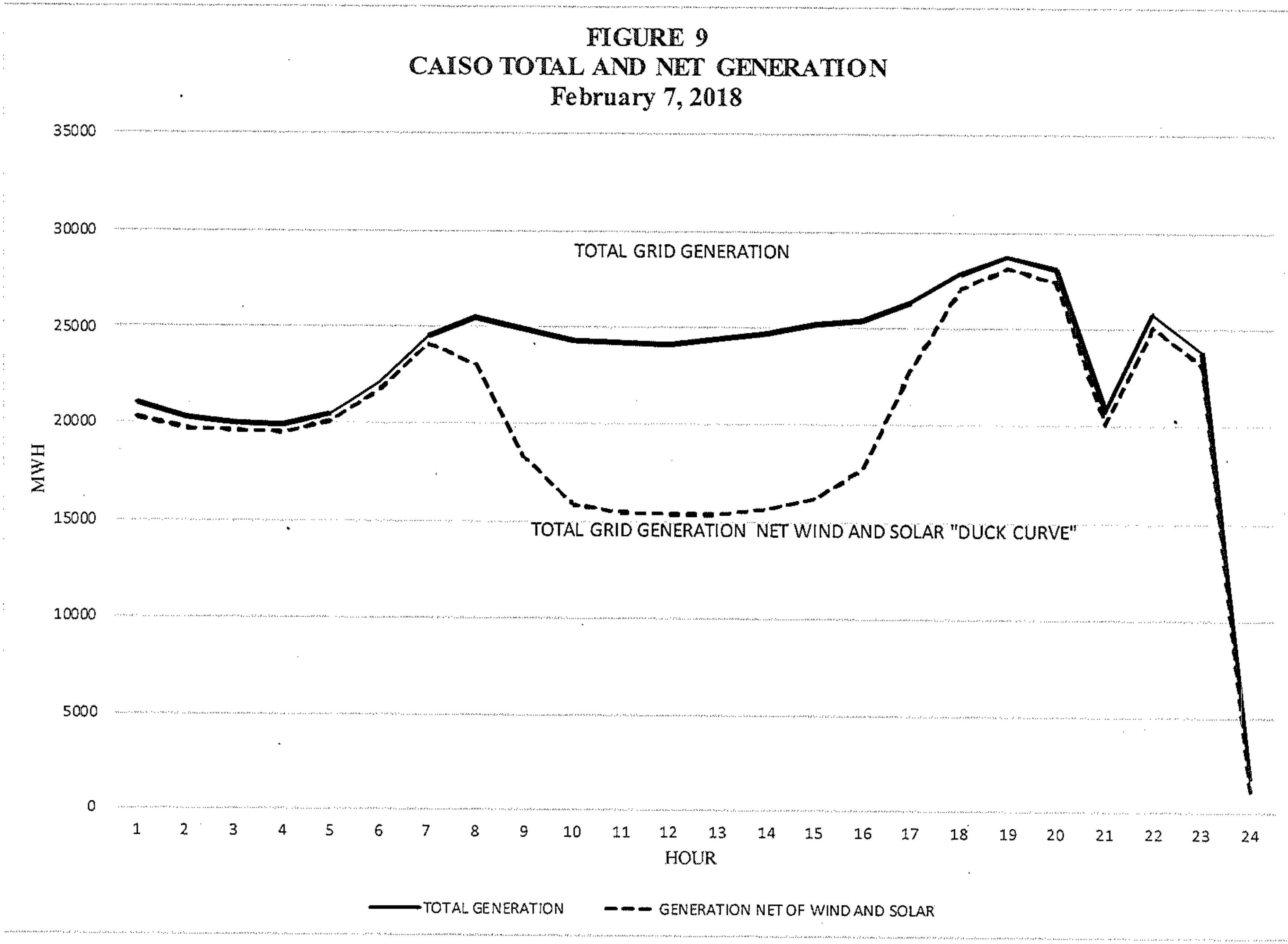


FIGURE 9
CAISO TOTAL AND NET GENERATION
February 7, 2018
35000
30000
25000
20000
15000
10000
5000
0
MWH
TOTAL GRID GENERATION
TOTAL GRID GENERATION NET WIND AND SOLAR "DUCK CURVE"
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR
TOTAL GENERATION
GENERATION NET OF WIND AND SOLAR

FIGURE 10
CAISO AVERAGE HOURLY LMP/AVERAGE ANNUAL LMP BY YEAR

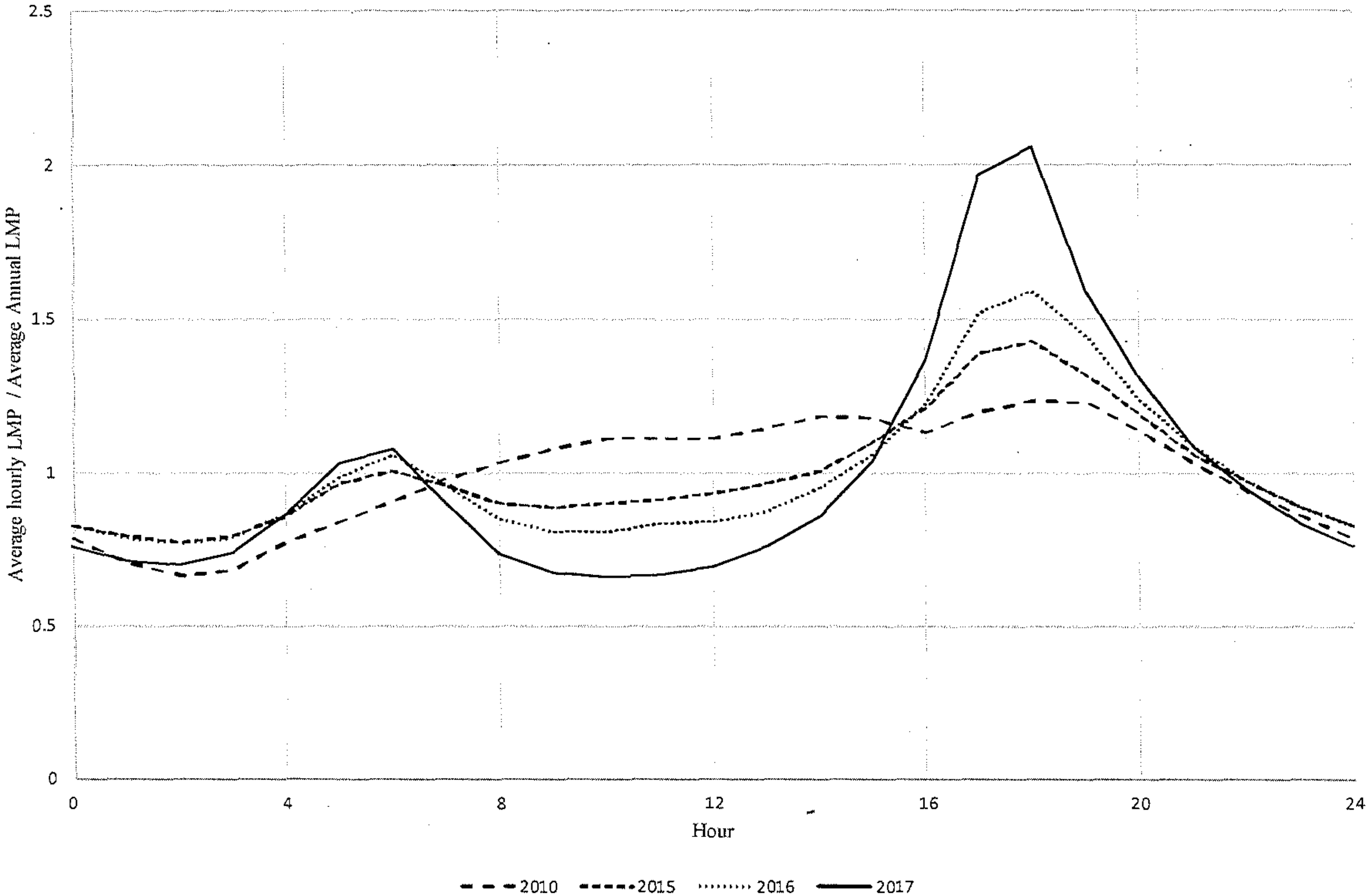


FIGURE 11
CAISO DAY-AHEAD PRICES SP15 and NP15
July 18, 2018

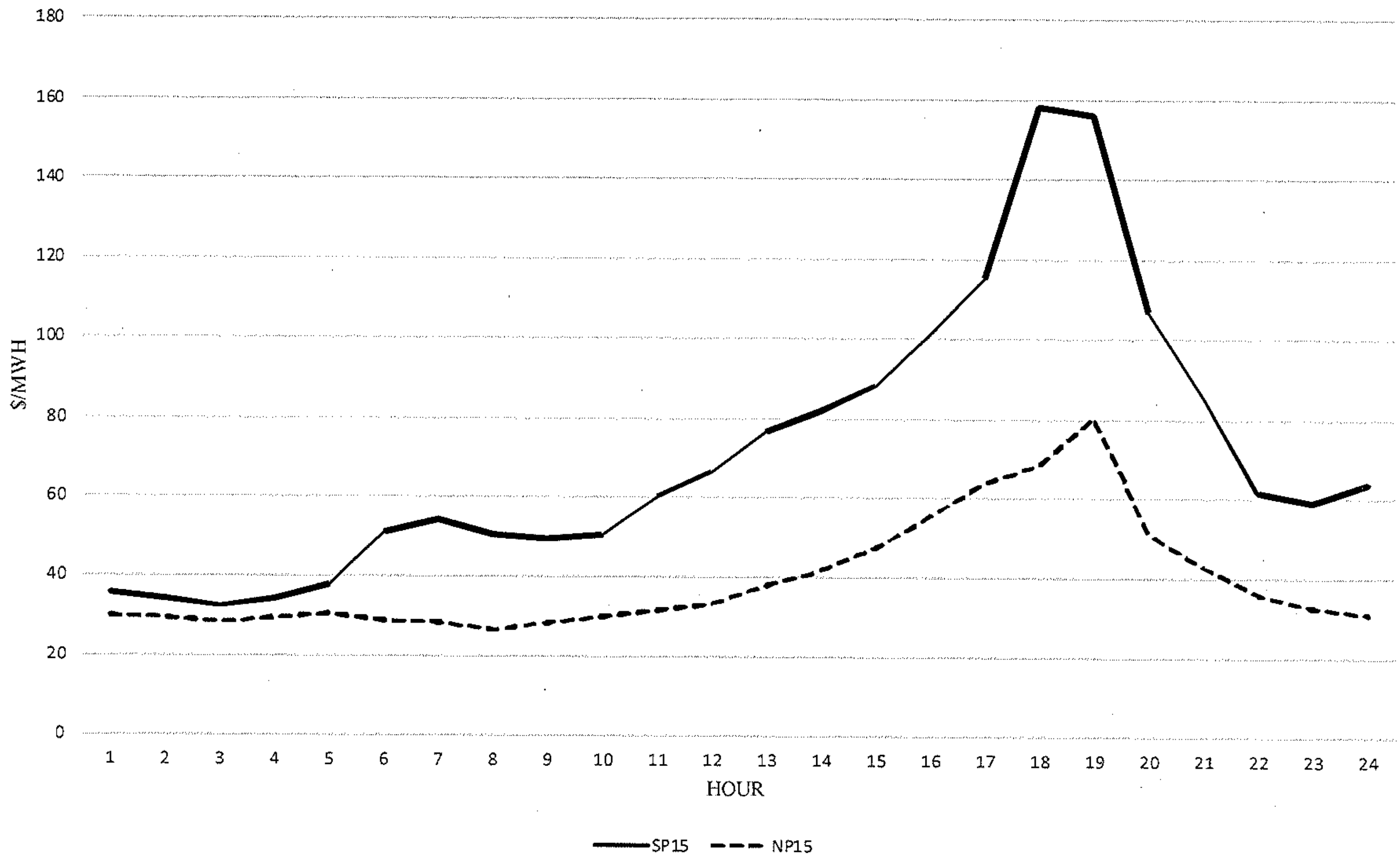


FIGURE 12
CAISO DAY-AHEAD PRICES NP15 and SP15
February 7, 2018

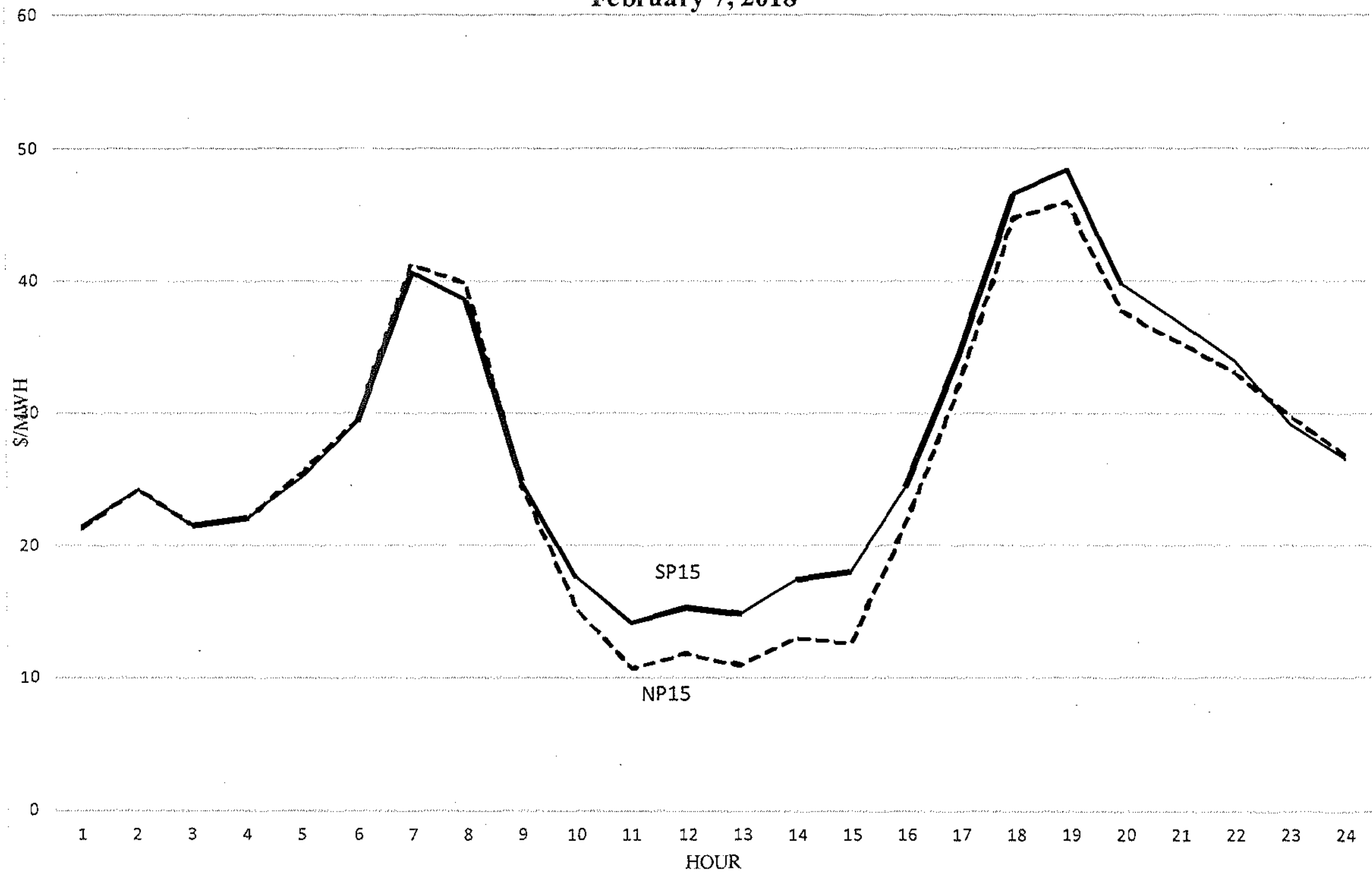
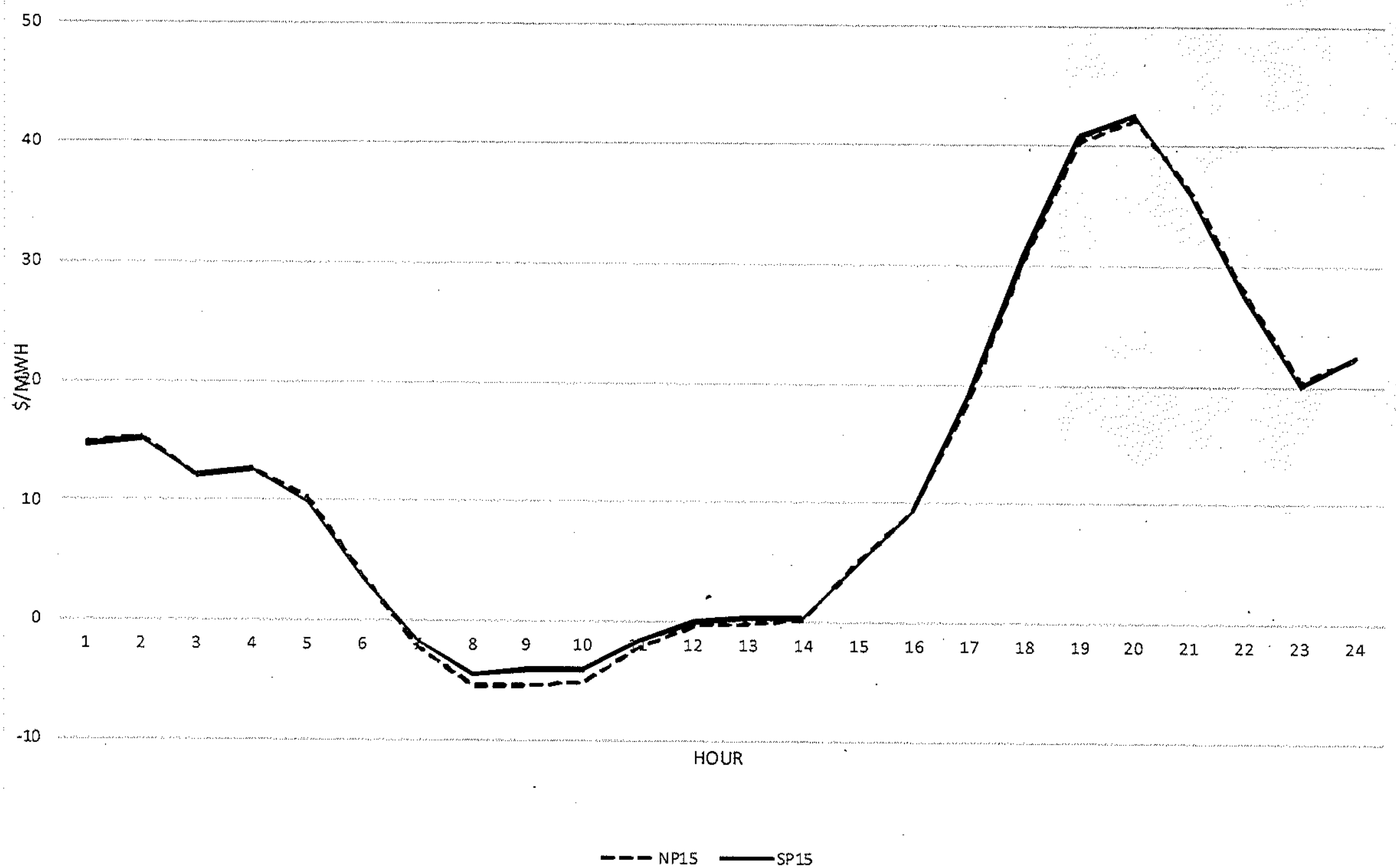


FIGURE 13
CAISO DH PRICES
June 10, 2018 (Sunday)



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