QUANTIFYING THE CONSUMER BENEFITS OF THE MARKET REFORMS IN THE REPORT, *CUSTOMER FOCUSED AND CLEAN*

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INTRODUCTION

This report quantifies the consumer benefits provided by the primary market reforms recommended in the November 2018 Wind Solar Alliance report *Customer Focused and Clean: Power Markets for the Future*.[1] That report qualitatively examined opportunities for improving the market and operating practices of the grid operators in the Midwest (the Midcontinent Independent System Operator, or MISO) and the Mid-Atlantic and Great Lakes states (PJM). Given the growth of wind and solar generation, the report focused on how wholesale electric market rules that were developed with conventional generators in mind can be improved to better accommodate the contributions and characteristics of new resources and help meet customers' and regulators' demand for clean, affordable electricity. As shown below, that report recommended many reforms to electricity markets for energy, capacity, and reliability services. As this report demonstrates, these reforms can also save consumers billions of dollars per year by improving efficiency and allowing renewable resources to provide reliability services to the grid.

ENERGY MARKET REFORMS

- Ensure energy market prices reflect the value of reliability.
- Bring self-scheduled resources into markets.
- Multi-Day Unit Forecasts
- Price the inflexibility costs of conventional generators.
- Ensure accurate, detailed generator bid parameters.
- Reduce operational over-commitment of conventional units.
- Create operating reserve zones.
- incent improvements in renewable energy forecasting
- Probabilistic Unit Commitment.
- Improve gas-electric coordination.
- Respect bilateral contracts.
- Allow flexible resources to bid flexibly without being inappropriately constrained by market power mitigation rules.
- Allow real-time prices and demand response aggregation for electricity customers and allow demand resources to set prices.
  - Streamline ISO seams.
  - Use advanced grid technologies and operating practices to improve utilization of existing transmission.

RELIABILITY SERVICES REFORMS

- Reactive power compensation.
- Remove barriers to renewable energy providing operating reserves like frequency regulation.
- Primary frequency response markets.
- Allow renewables to provide and set price for all reliability services.
- Create additional flexibility products.
- Make contingency reserves available to accommodate abrupt drops in renewable output.

CAPACITY MARKET REFORMS

- Respect state resource choices.
- Allow MOPR to be avoided through bilateral contracts
- Ensure capacity markets reflect renewable resources' true capacity value.
- Relax the requirement for capacity to perform year-round, and create seasonal rather than annual capacity products.
- Allow storage participation in capacity markets.
- Ensure conventional generators are not awarded excess credit relative to renewable resources.
- Efforts to add a fuel security component to the capacity market should be abandoned unless demonstrated to improve reliability or efficiency.
- Reform the capacity performance penalty structure to be symmetric
- Allow generators to retain their Capacity Interconnection Rights (CIRs) if capacity values change.
- Allow hybrid projects for purposes of meeting market rules

1 https://windsolaralliance.org/wp-content/uploads/2018/11/WSA_Market_Reform_report_online.pdf

This report quantifies the consumer benefits of the following categories of power market and grid operating reforms that were identified in the *Customer Focused and Clean* report:

CAPACITY

- **THE COST OF IMPOSING A MINIMUM OFFER PRICE RULE IN THE CAPACITY MARKET.** PJM has proposed a measure, called the Minimum Offer Price Rule or MOPR, that would make it difficult for renewable and nuclear resources that receive state incentives to participate in the capacity market. If implemented in a way that the contributions of those resources to meeting system capacity needs would not be counted, consumers would be forced to pay for redundant replacement capacity. This cost would only apply to PJM, as MISO only has a voluntary capacity market and has not proposed a MOPR policy to limit the participation of resources that receive incentives. This policy and the details of how it might be implemented in PJM are currently pending before the Federal Energy Regulatory Commission. For the purposes of this paper, the benefit of removing the MOPR policy is calculated based on the assumption that it would prevent incentivized nuclear resources and new renewable resources from receiving credit for their capacity value.

SELF-SCHEDULING

- **THE BENEFITS OF LIMITING THE SELF-SCHEDULING OF CONVENTIONAL GENERATORS.** In PJM and MISO, a significant share of conventional generators self-schedule their generation output instead of being dispatched by the centralized market. This can result in higher costs for consumers because the power plants that are being utilized may not be the most economic, and because there is less flexibility being offered into the market.

FLEXIBILITY

- **LOAD PARTICIPATION IN MARKETS.** Currently, most electricity rate structures do not provide consumers with an incentive to adjust their demand based on real-time changes in wholesale electricity market prices. There are several policy mechanisms by which electricity demand can become more price responsive, which would significantly reduce the cost of operating the power system.
- **INCENTIVIZE FLEXIBILITY THROUGH MARKET DESIGN.** Many of the energy and reliability services reforms recommended in *Customer Focused and Clean* focused on properly incorporating the cost of inflexibility into market prices and allocating that cost to inflexible resources, while also rewarding flexible resources for the benefits they provide to the power system. This saves consumers money by making power system operations more efficient.
- **ALLOW RENEWABLES, STORAGE, AND OTHER NEW RESOURCES TO FULLY PARTICIPATE IN MARKETS.** Currently, PJM and MISO market rules prevent renewable and storage resources from participating in reliability services markets. Preventing these resources from providing flexibility and other valuable reliability services increases consumer costs because more expensive resources must be used to provide those services.

SEAMS

- **STREAMLINE THE SEAMS BETWEEN ISO MARKETS.** Current market practices can cause unnecessary congestion at the seams between ISOs, and between ISOs and non-ISO areas, preventing economic transactions from occurring.

  The remainder of the paper is structured as follows. We first examine alternative methods that can be used to assess the value of market changes, and we provide an example that illustrates the sometimes complex interaction between different market changes. We then discuss the methods used in this paper to calculate the impacts of the selected market enhancements, followed by the results of our analysis. We conclude with a summary of our findings and suggestions for future analysis.

POTENTIAL APPROACHES TO EVALUATE THE VALUE OF MARKET ENHANCEMENTS

To understand the value and limits of this report, it is important to consider the range of methodology options for quantifying the value of market enhancements. Each of these comes with its own trade-offs, and therefore one must choose which approach(es) to take based on resources available for the effort, precision desired, and objective of the evaluation. This section provides a short overview of methodological options for this type of analysis.

PRODUCTION SIMULATION MODELS

Although there can be substantial differences between models, these tools simulate the operation of the power system, and can be used to examine alternative scenarios and assumptions. The required input data is substantial, especially when the analysis involves variable resources such as wind or solar.[2] Production simulation models follow algorithms that fully optimize the system, often defined as the minimum-cost outcome subject to reliability and other constraints. As such, these models cannot generally take human behavior into account when there is a market setting and human agents. However, alternative market structures can often be analyzed with this type of model.

Capacity markets and other aspects of long-term investment in the power system can be assessed with either long-term market/investment models or the traditional generation expansion planning models. The former allows for the calculation of various economic and financial metrics, sometimes considering uncertainty, to determine best future plant mix. The latter is another optimization model that pursues the least-cost generation portfolio over some future time period, based on various assumptions about technology and fuel costs. Both of these models can account for transmission constraints, and some can help in the evaluation of alternative transmission investment. Additional insights can be gained by taking the output from a planning model and using it as input to the higher-resolution operational models.

These models require substantial effort, expertise, and data, and they are therefore among the costliest approaches to assess market reforms. However, they do likely provide the deepest insights and best measures of the value of market enhancements. As explained above, many of the results in this analysis were obtained by extrapolating from the results of in-depth modeling conducted in previous studies.

TARGETED CALCULATIONS

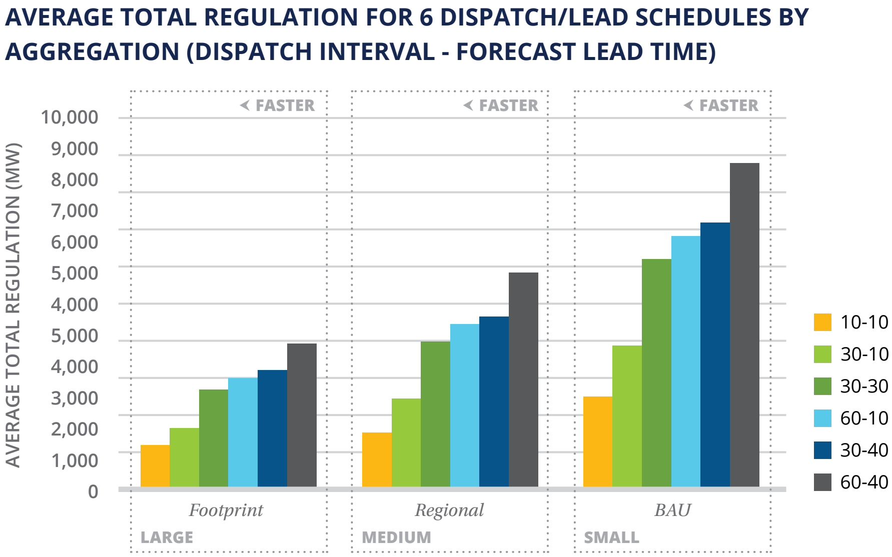
In some cases, one can approximate the change in a market structure by utilizing outputs from more detailed models, but not performing new modeling runs. In other cases, one can often use a subset of the full system data so that the analysis can focus on one aspect of interest. These approaches can often yield substantial insight; however, by their nature they do not account for the many complex interactions that regularly occur in the power system.

One example of this type of analysis is Milligan et. al.[3] Data for demand and wind energy production were obtained from other modeling projects. The data sets included 10-minute demand and 10-minute wind power production for approximately 30% annual wind energy penetration in the Western Interconnection of the U.S. The focus of the study was to analyze the impact of different dispatch time steps ranging from 10 minutes up to one hour, and the impact of balancing area (BA) coordination. An additional aspect of the analysis was to examine the impact of alternative “lock-down” intervals—the number of minutes prior to the dispatch that the final wind forecast could be delivered to the power system operator. A tool was applied to the data that calculated flexibility reserve requirements, and key results for three alternative levels of BA aggregation, three dispatch time steps, and three lock-down periods. Results appear in Figure 1, and we will return to this diagram below to examine some important lessons regarding how the order of market reforms can impact the value of a given reform.

2 Milligan, M.; Ela, E.; Lew, D.; Corbus, D.; Wan, Y; Hodge, B.; Kirby, B. (2012). Assessment of Simulated Wind Data Requirements for Wind Integration Studies. IEEE Journal on Sustainability. Vol. 3(4), October; pp. 620-626. Available at http://dx.doi.org/10.1109/TSTE.2011.2160880

3 Milligan, M.; King, J.; Kirby, B.; Beuning, S. (2011). Impact of Alternative Dispatch Intervals on Operating Reserve Requirements for Variable Generation. Ackermann , T., ed. Proceedings of the 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, 25-26 October 2011, Aarhus, Denmark. Langen, Germany: Energynautics GmbH; 6 pp.; NREL Report No. CP-5500-52506.

FIGURE 1. *Example of a targeted calculation*



Milligan, Kirby, King, Beuning (2011), The Impact of Alterntive Dispatch Intervals on Operating Reserve Requirements for Variable Generation. Presented at 10th International Workshop on Large-Scale Integration of Wind (and Solar) Power into Power Systems, Aarhus, Denmark. October

EXTRACTING AND EXTRAPOLATING FROM EXISTING STUDIES

Some of the results in this analysis were found by extrapolating from the results of previous studies that used sophisticated modeling to calculate the impact of market reforms. This method has value because in many cases, as there is often not sufficient time or financial resources to undertake either type of study discussed above. Instead, the analyst can focus on existing studies' outputs and insights and apply those to the problem at hand. When collecting existing work, it is likely that some of it applies fairly directly to the problem at hand; however, some of the existing work may be somewhat indirect. In that case, the analyst must use best professional judgement as to whether to include a given piece of work, or perhaps adapt it to help inform the project.

INTERACTIONS AMONG RELATED POLICIES

When considering multiple market enhancements, one must realize that the value of each enhancement depends on whether it is adopted before or after related policies that also increase system flexibility. For a good illustration, we focus on Figure 1. The figure is divided into three boxes. The left-most box, labeled "Large" shows results assuming full operational consolidation in the West. The "Medium" box shows results for a partial consolidation, roughly corresponding to three subregions aligned with the key transmission planning regions in the West. The "Small" box is based on each existing (at the time) balancing area, operating separately.

Within each box, there are calculations for multiple dispatch interval/time step pairs, as indicated in the legend of the graph. Thus, in the "Small" box, we see the West-wide regulation requirements for 10-minute dispatch with 10-minute lock-down, 30-minute dispatch with 10-minute lock-down, and other combinations including 30/30, 60/10, 30/40, and 60/40. The same dispatch/lock-down intervals were calculated also for the "Medium" and "Large" boxes.

Suppose an analyst wanted to answer the question: how much reduction in regulation would there be in the West if we moved from 60/40 dispatch to 10/10 dispatch? The answer depends on the starting place of the system. If each BA were operating separately, as in the "Small" box, then the impact of moving from a 60/40 to a 10/10 dispatch would be the difference between 8,777 megawatts (MW) of regulation and 2,440 MW of regulation, a reduction of 6,337 MW.

However, if operational consolidation followed the scenario in the "Medium" box, then the change in dispatch from 60/40 to 10/10 would result in a change from 5,813 MW to 1,547 MW, a reduction of 4,267 MW. And if operational consolidation would have previously occurred as represented by the "Large" box, the improvement from 60/40 to 10/10 would represent a reduction in regulation requirements from 3,942 MW to 1,198 MW, a reduction of 2,743 MW.

There are, of course, many other potential combinations of changes in operational coordination that we could extract from this graph; Table 1 contains the same information further illustrates. However, the key point is that when we consider a suite of market enhancements, we must be cognizant of the potential interactions between them, which result in benefits that are dependent on whether other improvements have already been made. These interactions also imply that policy-makers may want to consider a pathway forward that can achieve larger savings first.

TABLE 1. *Reduction in regulation requirements due to faster dispatch and larger balancing region*

REGULATION REQUIREMENTS (MW) FOR ALTERNATIVE DISPATCH/LEAD TIMES AND SIZE OF BALANCING REGION

DISPATCH INTERVAL/ LEAD TIME (MINUTES)	LARGE	MEDIUM	SMALL	MAXIMUM REDUCTION
10-10	1198	1547	2440	1242
30-10	1718	2444	3873	2156
30-30	2705	3975	6168	3464
60-10	3027	4453	6831	3804
30-40	3184	4696	7205	4021
60-40	3942	5813	8777	4835

The example provided in this discussion shows that the value of a particular improvement in operations or operational markets have important interactions. Whenever this type of interaction is possible, we take that into account in the remainder of this paper.

For our analysis of potential market improvements, we used a set of targeted calculations, which are based upon data in the literature. When there is potential interaction between multiple market enhancements, we account for them in our analysis. The next section describes our approach for each of the market reforms we address.

METHODOLOGY

For all calculations, we assumed that the societal benefits of proposed reforms would ultimately fully flow through to consumer benefits as the market moves to a new long-term equilibrium. In reality, retail electric rates are subject to regulatory lag, and some of the societal savings may be realized as producer surplus. As a result, it may take some time for the calculated savings to fully flow through to consumers.

- **THE COST OF IMPOSING A MINIMUM OFFER PRICE RULE (MOPR) IN THE CAPACITY MARKET.** PJM has proposed a MOPR measure that would make it difficult for renewable and nuclear resources that receive state incentives to participate in the capacity market. That policy is currently pending before the Federal Energy Regulatory Commission, and the details of possible exemptions that could allow incentivized resources to provide capacity value have not yet been established. Depending on how such a policy were implemented, the contribution of some or all of those resources to meeting system capacity needs could not be counted, and consumers would be forced to pay for redundant replacement capacity.

In the table below, the cost of this redundant capacity is calculated by summing the actual capacity contributions of nuclear and new renewable resources that would not be counted under a MOPR policy that prevents those resource from clearing the capacity market, and then multiplying that by the average clearing price in PJM's capacity market over the last five years of $120.26/MW-day.[4] The nameplate capacity for each resource (second column) is multiplied by the capacity value of that resource[5] (third column) to calculate the actual capacity contribution of the resource (fourth column). This estimate is conservative because a policy that increases the demand for capacity while restricting the supply of eligible resources will increase the price for all capacity that clears the market.

In theory, this surplus capacity could provide some benefit to consumers by improving the reliability of the power system.[6] However, analysis by PJM and others has shown that the marginal value of additional capacity rapidly diminishes to near-zero once capacity reserves exceed 20% of expected electricity demand.[7] PJM capacity reserve margins exceed 30% for the foreseeable future, and would be increased even further if redundant capacity were required as part of a MOPR on nuclear and renewable resources, so the benefit of this additional capacity is likely to be negligible.[8]

As mentioned above, the impact of a capacity market MOPR is not evaluated in MISO because it does not have (or need) a mandatory capacity market and a MOPR policy has not been proposed in MISO (nor should it be). The impact of a capacity market MOPR in PJM is not calculated for a high renewable scenario because it is unlikely that a MOPR policy would still be in place in a very high renewable penetration future.

TABLE 2. *Capacity value excluded under a potential MOPR*

RESOURCE	MW NAMEPLATE	CAPACITY VALUE	ACCREDITED CAPACITY MW
NJ nuclear units	3631	98.397%	3,573
IL PJM nuclear units	11276	98.397%	11,095
MD post-2018 ORECs	70	27%	19
NJ Tier 1 RPS, wind	2440	13%	317
NJ Tier 1 RPS, solar	1545	60%	927
NJ solar carveout	2598	60%	1,559
NJ offshore wind	3500	27%	945
Incremental Illinois RPS demand 2019-2030, wind	911	13%	118
Incremental Illinois RPS demand 2019-2030, solar	2015	60%	1,209
Other post-2018 state RPS demand, wind	3730	13%	485
Other post-2018 state RPS demand, solar	9134	60%	5,480
			SUM 25,727 MW

4 https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx

5 https://www.pjm.com/-/media/planning/res-adeq/res-reports/2012-2016-pjm-generating-unit-class-average-values.ashx?la=en

6 http://www.law.nyu.edu/sites/default/files/upload_documents/ER18-1314%20Protest%20of%20Joint%20Consumer%20Advocates%20and%20Certificate%20of%20Service.pdf

7 https://www.pjm.com/~/media/planning/res-adeq/2017-pjm-reserve-requirement-study.ash, page 39; see also https://www.xcelenergy.com/staticfiles/xe/PDF/Attachment%20AKJ-2.pdf, page 391, and http://www.ercot.com/content/wcm/lists/143980/10.12.2018_ERCOT_MERM_Report_Final_Draft.pdf

8 We note that there may be potential value to additional capacity that exceeds the capacity that is required to meet resource adequacy requirements. This value can be difficult to assess, and is thus outside the scope of most market designs. An example of this type of excess reserve is a long-term "strategic" reserve that is put in place as an extra precaution. We note, however, that even though this may increase long-term reliability, it is costly. As illustrated by the three studies cited in the footnote above, adding capacity above the reserve margin provides rapidly diminishing marginal returns. Brattle's analysis for ERCOT quantifies how the cost of this additional capacity greatly exceeds its benefits.

- **THE BENEFITS OF LIMITING THE SELF-SCHEDULING OF CONVENTIONAL GENERATORS.** The market bidding behavior of generators is not typically disclosed, which prevents the conclusive identification of specific plants that are self-scheduling their generation. Our approach was to identify coal plants that are operating at significantly higher capacity factors than would be predicted based on their economics as a statistical indicator of the amount of coal generation that is being self-scheduled. The net cost of the generation provided by these plants in excess of levels that appear to economic was then calculated.

  Plant-level generation, fuel consumption, and fuel price data were obtained from Energy Information Administration's Form 923 database.[9] For plants for which fuel price data was not available, average fuel prices for the state or region were used instead.[10] Fuel-related marginal production costs for each plant were then calculated based on the fuel consumption times the fuel price divided by the generation.

  As expected, the general trendline is that generators with lower marginal production costs operate at higher capacity factors. However, a number of coal plants are outliers above that trendline, in that they operate at relatively high capacity factors even though their marginal production costs are higher than other plants. Only plants for which annual generation exceeded 100,000 MWh were included in establishing the trendline, to remove the impact of outlier plants with insignificant generation yet very high or low fuel costs.

  Coal plants falling above the trendline and with above average fuel costs were identified as plants suspected of self-scheduling. Those plants, which can be seen in the upper right quadrant of the following charts, were then removed from the sample set so that the average coal plant fuel costs and fuel cost versus capacity factor trendline could be calculated for coal plants that do not appear to self-schedule. The amount of generation from the coal plants suspected of self-scheduling in excess of the level predicted by the trendline was then calculated, and that amount of generation was multiplied by the $/MWh amount by which the plant's fuel-related marginal production cost exceeds the average fuel-related marginal production cost for non-self-scheduling plants. Using that method, excess fuel costs due to coal plant self-scheduling in 2017 were calculated to exceed $85 million in PJM and $127 million in MISO. This cost was assumed to be the same for either a low or high renewable penetration, as the consumer cost is primarily driven by the cost of the uneconomic self-scheduled generation.

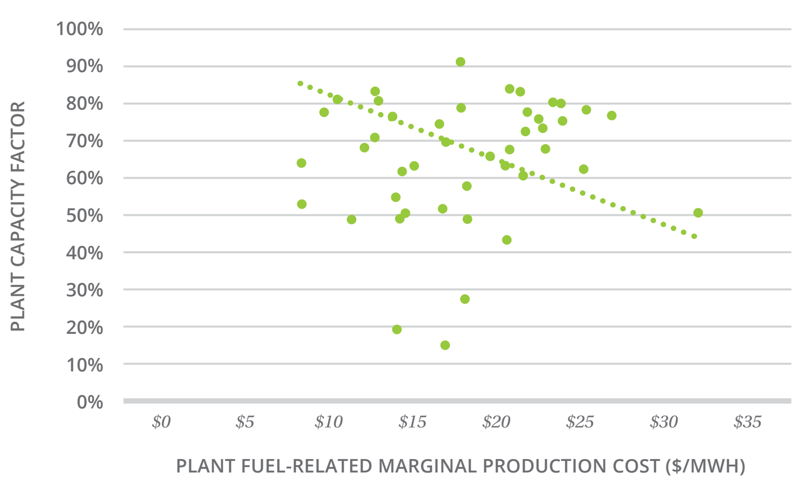


FIGURE 2. *MISO coal plant capacity factor (y-axis) versus fuel-related marginal production cost (x-axis), with linear trendline*

9 https://www.eia.gov/electricity/data/eia923/
10 https://www.eia.gov/electricity/monthly/

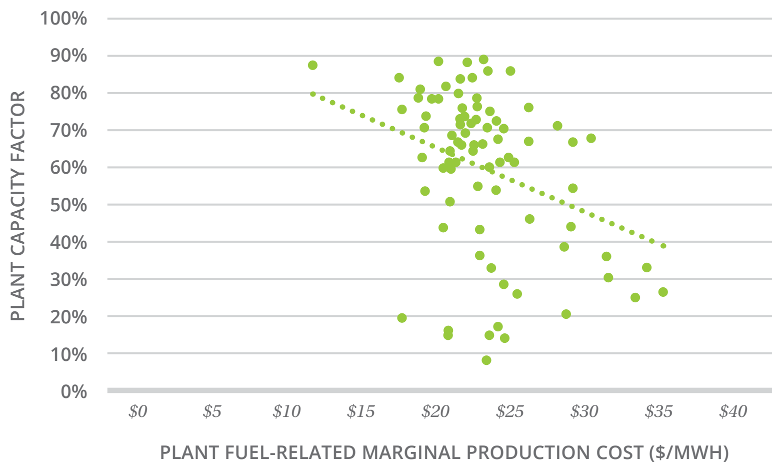


FIGURE 3. *PJM coal plant capacity factor (y-axis) versus fuel-related marginal production cost (x-axis), with linear trendline*

This is likely a conservative estimate of the full cost of self-scheduling, as it does not include the fixed and carrying costs associated with the retention of coal plant capacity that would be uneconomic without self-scheduling. It also does not capture the balancing and operating reserve costs that can be imposed on other resources because self-scheduled plants tend to provide less flexibility to the power system. Finally, it does not include marginal production costs other than fuel, such as variable O&M costs, which may be higher at self-scheduled plants than at other coal plants. Recent analysis using a similar methodology but also using proprietary data on plant-specific variable O&M costs found self-scheduling costs that are higher than those indicated here.[11] Our results, which were calculated entirely using public EIA data and therefore only used plant-specific fuel costs, lend support and confirmation to the results of that previous analysis. We believe that both of our analyses provide sufficient evidence of the high cost of self-scheduling for state regulators, Independent System Operators (ISOs) like PJM and MISO, and ISO market monitors to use their access to confidential plant-specific cost and scheduling data to further examine the issue.

State regulators and others with access to confidential information also have greater visibility into plant-specific factors that may drive self-scheduling, as well as potential solutions for minimizing self-scheduling. For example, inflexible requirements in long-term fuel supply or transportation contracts (e.g., railroad or barge contracts in the case of coal plants) appear to be a factor that drives some fossil-fired power plants to self-schedule.

Long-term contracts provide value by helping to mitigate price risk and other risks in fuel procurement and in electricity markets. However, if contract terms are too restrictive, they can constrain the system from an optimal outcome. The purpose of the contract is to provide some certainty to buyers and sellers, but this means the price and quantity are codified and not able to respond in a flexible manner. In general, contract constraints have a shorter-term impact, because over the longer-term contracts expire, can be renegotiated, or otherwise become more flexible.

Some contracts contain minimum delivery requirements, take-or-pay provisions, or other mechanisms that impose an additional cost on the fuel buyer if they consume less than some specified amount of fuel. These contract terms give the fuel seller a level of certainty that fixed costs can be recovered (e.g., capital investments in a mine or railroad infrastructure) as variable costs by including those costs in the price of each unit of fuel sold over time. Given competition from low-cost generation from gas and renewable resources, it is likely that many coal generators with such contracts are currently struggling to meet these fuel contract minimum requirements. For a fuel buyer who is at risk of falling below a minimum requirement, these provisions create an incentive for the power plant to offer its electricity into wholesale markets at a price below its true marginal cost of producing electricity. This allows the plant to be dispatched to operate more, which allows it to consume more fuel and therefore avoid or minimize the contract penalties. This is socially suboptimal behavior, as economic theory states that the choice of which power plants to commit and dispatch should only be based on true variable costs (marginal production costs associated with producing and consuming a marginal increment of fuel), while fixed costs that have already been incurred should

11 https://blog.ucsusa.org/joseph-daniel/the-coal-bailout-nobody-is-talking-about

be ignored because they are “sunk costs.” Subsidizing variable costs by factoring in the value of avoiding contract penalties that recover fixed costs can harm economic efficiency by incentivizing excessive commitment and dispatch of these generators.

Fuel contract terms are almost always confidential, but it appears that many contain penalties or other off-ramps that would allow the generator to get out of the minimum fuel delivery requirements at some cost. In other cases, it may be possible to renegotiate the contract. State Commissions have visibility into fuel supply contract terms, and they should examine these contracts to determine the best solution for ratepayers. One potential solution is that regulators should require plant owners to offer into electricity markets based on their true variable costs, and the regulator can separately allocate the sunk or fixed costs associated with contract penalties or renegotiation (by “separately” we mean in a way that the penalties are not included in marginal cost offers based on variable costs, and therefore do not affect the commitment and dispatch of the plant). It would be up to the Commission to decide how to allocate any fixed or sunk contract costs to ratepayers versus utility shareholders, though regulatory principles typically allocate any cost that was prudently incurred or previously approved by the Commission to ratepayers. This would ensure that fixed costs do not interfere with optimal dispatch of the power system.

Regardless, the allocation of sunk costs is irrelevant for economic efficiency going forward, as long as generator dispatch decisions are based on variable costs and not fixed costs. An analogy is a professional sports team buying out the contract of a player who is injured or otherwise no longer fit to play. The decision about whether to play the player should be separate from the decision about how to terminate the contract at minimal cost, as that represents a sunk cost. No sports team would continue playing a seriously injured player just because they had signed a long-term contract with the player, just as utilities should not operate uneconomic power plants just because they signed a contract a long time ago.

FLEXIBILITY

- **LOAD PARTICIPATION IN MARKETS.** Lawrence Berkeley National Laboratory (LBNL) analysis quantified how price-responsive load increases the value of wind and solar at varying renewable penetrations on the California Independent System Operator (CAISO) power system.[12] At a 10% wind and 10% solar penetration, providing a rate structure that incentivizes load to be more responsive to real-time price signals increases the societal value of wind and solar by around $3/MWh, which translates to $3 times 20% or $0.60/MWh for all generation in a low renewable scenario. At a higher renewable penetration of 40% wind and 30% solar, the value for wind and solar generation is around $6/MWh, which translates to $6/MWh times 70% or $4.20/MWh for all generation. These results are consistent with the range of savings identified in an economics paper that analyzed the CAISO power system without large amounts of renewable generation.[13]

  As mentioned above, a common analytical approach involves extrapolating from existing analysis. While the above results — and some of the results discussed below – were initially calculated for the CAISO power system, we believe the operational characteristics of the MISO and PJM power systems are similar enough to the CAISO system that benefits should be roughly comparable on a $/MWh-basis. CAISO, PJM, and MISO are all large markets that are centrally dispatched at fast intervals, and therefore would score similarly on most flexibility metrics.[14] MISO and PJM are significantly larger than CAISO, but CAISO has a more flexible generating fleet given its abundance of hydroelectric and gas generation, so those differing factors should roughly offset.

- **INCENTIVIZE FLEXIBILITY THROUGH MARKET DESIGN.**

  The LBNL report discussed above analyzed how the addition of quick-start combined cycle gas capacity would add value to the CAISO power system with varying levels of renewable generation. That analysis found minimal impact on the value of wind and solar generation, apparently because the flexibility of the CAISO power system was already adequate to meet the system ramping needs with increased renewable penetrations. This finding is confirmed

12 https://emp.lbl.gov/sites/all/files/lbnl-6590e.pdf

13 http://faculty.haas.berkeley.edu/borenste/download/EnJo05RTPsim.pdf

14 See the metrics and examples of types of power systems described on page 23 here; all three of these RTOs would likely qualify for the highest flexibility rating as a “large RTO with spot markets.” https://www.nrel.gov/docs/fy09osti/46273.pdf

by analysis NREL performed for part of the Rocky Mountain region, which showed that increasing the flexibility of the conventional generator fleet provided no measurable value at wind and solar penetrations of up to 16%, and insignificant savings until penetrations exceeded 30%.[15] As a result, we infer the value of greater system flexibility to be low for MISO and PJM at low renewable penetrations, as the supply of flexibility is adequate to meet the need.

However, studies indicate that flexibility on those power systems becomes valuable at higher renewable penetrations. Recent National Renewable Energy Laboratory (NREL) analysis found that increasing the flexibility of the conventional generation fleet at a 70% renewable penetration in the Eastern U.S. would yield $2 billion in savings across 3,300 TWh of demand, or $0.61/MWh.[16] Lending credence to this estimate, NREL's Rocky Mountain analysis yielded similar results, with savings of $0.54/MWh from increasing conventional generator flexibility at a 52% wind and solar penetration.[17]

- **ALLOW RENEWABLES, STORAGE, HYBRID GENERATORS, AND OTHER NEW RESOURCES TO FULLY PARTICIPATE IN MARKETS.**

The LBNL analysis discussed above also examined how adding energy storage adds value to the power system with varying levels of renewable generation. With wind and solar each providing 10% of energy, it found that the value to the system was increased by around $1.50/MWh, or $0.30/MWh in savings when divided across all MWh of demand.

Recent analysis conducted for First Solar by consulting firm E3 found that making solar fully dispatchable significantly increased the value of solar generation on the Tampa Electric power system. With solar generation meeting about 24.5% of demand on the Tampa system, the average value of solar generation increased by $7.40/MWh, which translates to total savings of $1.81 across all MWh of demand.[18]

It should be noted that the Tampa Electric system is considerably smaller than PJM or MISO, which tends to limit its operating flexibility as well as the geographic diversity of renewable resources. In addition, this analysis only deployed solar generation; because wind and solar output tend to be negatively correlated in most regions, the combined penetration of wind and solar could likely reach much higher levels before flexibility limits were hit and renewable flexibility became highly valuable. Total renewable penetrations would likely have to reach much higher levels before comparable savings from renewable flexibility were realized on a larger power system. As a result, our analysis treats these results as representative of a "high" renewable penetration, even though the actual penetration was less than 25% of electricity demand.

SEAMS

- **STREAMLINE THE SEAMS BETWEEN ISO MARKETS.** Previous work co-authored by Michael Milligan quantified the impact of increasing the geographic scope of power markets in the Western U.S. at moderate renewable penetrations. [19]Importantly, this result is the incremental impact of geographic size after measures to increase power system flexibility have been fully implemented. As a result, this result properly accounts for the interactions between the above policies to increase system flexibility and policies that increase the geographic scope of markets.

15 Savings from increased conventional generator flexibility at 32% wind and solar penetration were around half of one percent of total production costs. https://www.nrel.gov/docs/fy14osti/62275.pdf, pages 10, 18

16 https://www.nrel.gov/docs/fy18osti/71465.pdf

17 Calculated from $42.4 million in savings across 79,000,000 MWh of demand. https://www.nrel.gov/docs/fy14osti/62275.pdf, page 18

18 The scenario with 2,400 MW of solar capacity has the potential to meet 27.8% of Tampa Electric's demand, but because 11.9% of the available solar resource is curtailed in the dispatchable renewable case, it meets 24.5% of the demand. See pages 39-40: https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

19 See page xviii at https://www.nrel.gov/docs/fy13osti/57115.pdf

The NREL study that examined 70% renewable penetrations in the Eastern U.S. also examined the impact of reducing the seams between markets. That study found $2 billion in savings across 3,300 TWh of demand, or $0.61/MWh.[20] Based on the results of the Western study that calculated the interaction between flexibility measures and seams measures, this $2 billion in savings was scaled down by a factor that accounts for the degree of those overlapping impacts. Specifically, in the Western study the larger footprint provided $294 million in benefits when implemented alone, but $146 million if implemented after increasing system flexibility by moving from hourly to 10-minute dispatch. As a result, the $2 billion was scaled down by multiplying by the ratio 146/294.

RESULTS

Operating reforms that facilitate the participation of renewable resources in electricity markets also provide large savings to consumers. The following tables report the consumers savings from the capacity, flexibility, and seams reforms discussed above. Because these market reforms become more valuable at higher renewable penetrations, the consumer benefits of each reform are estimated for low and high renewable penetrations, as indicated by "low" and "high."[21]

As discussed earlier, there are interactions among the proposed flexibility reforms that cause the benefits of initial policies to be greater than subsequent policies because the initial policy has provided the "low-hanging fruit" for helping to meet system flexibility needs. In economics terminology, policies to increase system flexibility tend to be substitutes for each other, as supply from one source of flexibility helps meet the total demand for flexibility and thus reduces the demand (and value) for other sources of flexibility.

The broad categories of capacity, self-scheduling, seams, and flexibility measures are assumed to have minimal interactions with each other, so the bolded subtotals of benefits from each of those three categories are summed to calculate total benefits. However, within the flexibility category, there are assumed to be larger interactions among the various policies to increase flexibility. To be conservative, the results from the various measures within the flexibility category are not summed, but rather the maximum value for any one flexibility measure is presented as a low-end estimate of the combined impact of all flexibility policies.

If multiple flexibility policies were enacted, it is highly likely that the total benefits would be greater than the conservative values reported below. Further analysis using methods like those used in the NREL Energy Imbalance Market analysis discussed above would be needed to determine the full extent of the interactions among different flexibility policies. The values reported below can be viewed as a low-end estimate for the combined benefit of flexibility policies; a high-end estimate could be calculated by summing the benefits of the individual flexibility reforms. The true answer almost certainly falls somewhere in between those bookends, and would depend on the total supply and demand for flexibility on the power system at that time.

As noted above, the impact of a capacity market MOPR is not evaluated in MISO because it does not use a mandatory capacity market and a MOPR policy has not been proposed in MISO. The impact of a capacity market MOPR in PJM is not calculated for a high renewable scenario due to doubt that a MOPR policy would still be in place in a very high renewable penetration future.

In the last row, the bolded results for the capacity, self-scheduling, flexibility, and seams reforms are summed. The two cells in the lower right show that, across PJM and MISO, the proposed reforms yield around $2.5 billion in annual consumer savings at low renewable penetrations, and over $6.9 billion in annual savings at high renewable penetrations.

20 https://www.nrel.gov/docs/fy18osti/71465.pdf

21 The renewable penetration is defined as "high" when there are frequent periods of system-wide renewable curtailments due to low net load (as opposed to localized curtailments due to transmission congestion, which account for almost all curtailment today, except for some hours of system-wide solar curtailment midday in CAISO and some hours with high wind and low load in SPP and ERCOT). The renewable penetration at which system-wide curtailment begins to frequently occur depends on the system's flexibility, load pattern, and other factors, and will generally occur sooner for solar than for wind due to the greater concentration of solar output into a smaller share of hours.

TABLE 3. *Annual consumer savings from proposed market reforms, in millions of dollars*

SAVINGS IN MILLIONS OF $	PJM LOW	PJM HIGH	MISO LOW	MISO HIGH	TOTAL LOW RE	TOTAL HIGH RE
Capacity: MOPR	**$1,130**	**NA**	**NA**	**NA**	**$1,130**	**NA**
Limit self-scheduling	**$85**	**$85**	**$127**	**$127**	**$212**	**$212**
Flexibility: Price-responsive demand	$484	$3,387	$410	$2,871	$894	$6,259
Flexibility: Market design	$0	$489	$0	$414	$0	$903
Flexibility: Renewables and storage provide services	$242	$1462	$205	$1,240	$447	$2,702
Flexibility combined	**$484**	**$3,387**	**$410**	**$2,871**	**$894**	**$6,259**
Seams	**$141**	**$243**	**$119**	**$206**	**$260**	**$449**
Total savings, capacity+ flexibility+seams	**$1,840**	**$3,715**	**$657**	**$3,204**	**$2,496**	**$6,919**

For most policy reforms, these total savings were calculated by determining the value they provide for the average MegaWatt-hour (MWh) of energy demand served in each market, and then multiplied by the total MWh of demand in PJM and MISO to arrive at the figures above.[22] Those $/MWh results are also provided below. Because PJM and MISO are both very large power systems with comparable levels of flexibility, many of the flexibility-related reforms are assumed to provide comparable per-MWh benefits in MISO and PJM.

TABLE 4. *Annual consumer savings from proposed market reforms, per MWh of demand*

SAVINGS, $/MWH OF DEMAND	PJM LOW	PJM HIGH	MISO LOW	MISO HIGH
Capacity: MOPR	**$1.40**	**NA**	**NA**	**NA**
Limit self-scheduling	**$0.11**	**$0.11**	**$0.19**	**$0.19**
Flexibility: Price-responsive demand	$0.60	$4.20	$0.60	$4.20
Flexibility: Market design	$0	$0.61	$0	$0.61
Flexibility: Renewables and storage provide services	$0.30	$1.81	$0.30	$1.81
Flexibility combined	**$0.60**	**$4.20**	**$0.60**	**$4.20**
Seams	**$0.17**	**$0.30**	**$0.17**	**$0.30**
Total savings, capacity+ flexibility+seams	**$2.29**	**$4.61**	**$0.96**	**$4.69**

Finally, the results can also be expressed in terms of annual savings for a typical household with the national average consumption of 10.4 MWh per year.[23] Across MISO and PJM, individual states have between 27% lower and 37% higher average residential electricity consumption than the national average, with states in warmer climates tending to have higher consumption primarily due to higher air conditioning demand.

22 https://dataminer2.pjm.com/feed/hrl_load_metered/definition; https://docs.misoenergy.org/marketreports/20171231_rfal_HIST.xls
23 https://www.eia.gov/tools/faqs/faq.php?id=97&t=3

TABLE 5. *Annual savings from proposed market reforms, per typical residential customer*

ANNUAL SAVINGS PER AVERAGE RESIDENTIAL CUSTOMER	PJM LOW	PJM HIGH	MISO LOW	MISO HIGH
Capacity: MOPR	**$14.57**	**NA**	**NA**	**NA**
Limit self-scheduling	**$1.10**	**$1.10**	**$1.93**	**$1.93**
Flexibility: Price-responsive demand	$6.24	$43.68	$6.24	$43.68
Flexibility: Market design	$0	$6.30	$0	$6.30
Flexibility: Renewables and storage provide services	$3.12	$18.85	$3.12	$18.85
Flexibility combined	**$6.24**	**$43.68**	**$6.24**	**$43.68**
Seams	**$1.82**	**$3.13**	**$1.82**	**$3.13**
Total savings, capacity+ flexibility+seams	**$23.73**	**$47.91**	**$9.99**	**$48.74**

SUMMARY AND CONCLUSIONS

In this paper we describe our analysis of some of the key market enhancements described in the Nov 2018 Wind Solar Alliance report. We used methods that allowed us to build on the work of others, adapting those results to provide an estimate of the value of key market enhancements. As such, our results are not intended to provide precise calculations of the value of these reforms, and this initial analysis could be built upon with more detailed analysis and modeling. However, we believe that our results provide a good preliminary estimate of the value of these reforms, and our results show significant consumer benefits could be obtained by adopting these market changes. Significant consumer savings could be realized by:

- Ensuring the capacity value contributions of all resources are accounted for, preventing the retention or addition of unneeded capacity.
- Improving the operational efficiency of bulk power markets by moving more resources away from self-scheduling and into the economic optimization that is already performed by market operators.
- Incentivizing flexibility in the market design, providing useful signals for investors to develop flexibility resources needed for efficient power system operation, and incentivizing existing flexibility to be efficiently incorporated into operations.
- Removing artificial barriers preventing renewables, storage, and demand response from participating in markets.
- Improving the seams between markets, thereby lowering transaction costs of economic imports and exports between neighboring systems.

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