UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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PJM Interconnections, L.L.C.	)	Docket No: ER19-1486-000
	)	

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WHITEPAPER ON RTO/ISO MARKET DESIGN CHANGES TO INCREASE OPERATIONAL FLEXIBILITY

This paper discusses the operational challenges that independent system operators ("ISOs") and regional transmission organizations ("RTOs") will face in the future as the generation mix evolves and the nature of system loads change. These operational challenges will largely be driven by changes in "net load" – load minus the output from grid-connected intermittent generation - becoming more uncertain and characterized by steeper ramps compared to the traditional load profile that ISO/RTO operators have served in the past. The first section of this paper explains the concept of net load and the factors that will make it more challenging for ISO/RTO operators to balance in the future. The second section explains the market design changes ISOs/RTOs have considered or adopted to address the operational challenges associated with the expected changes in net loads. The third section gives an overview of some of the factors that are expected to make net load more uncertain and fast-ramping in PJM and explains at a general level that PJM's proposal to procure additional reserves in Docket No. EL19-58-000 is a reasonable approach to address those operational challenges.

I. ISO/RTO market mechanisms to increase operational flexibility

Two factors that have historically made it easier for ISO/RTO to maintain the power balance and carry the system's reserve requirements are expected to change in ways that will make these tasks more difficult. First, the generation resources on the system historically were generally dispatchable rather than intermittent, which meant that with the exception of forced outages, the operator largely exercised control over and could reasonably rely on the generation of the resources in the generation fleet.[1] Operationally this meant that ISO/RTO operators had a significant amount of dispatchable thermal resources that could be dispatched up and down to balance loads because the majority of the resources were dispatchable as opposed to intermittent. Even if a particular generation resource did not (or could not) respond to dispatch instructions from the ISO/RTO to increase or decrease generation output, the operator could confidently rely on the availability of that resource to serve load in the next few hours or the following day(s). Second, system loads followed a predictable diurnal pattern and uncertainties were largely driven by weather, which could be forecasted with reasonable precision.

[1] ISO/RTO operators are also aware of scheduled or planned outages for resource maintenance, frequently well advance, which made such "unforced outages" easier to plan for and manage.

Both of these aspects – a system composed of mostly dispatchable and non-intermittent resources and generally predictable loads – are changing. The introduction of grid-connected intermittent resources meant that ISO/RTO operators had to change their objective function and address the challenge of balancing net load (i.e., load minus the output from grid-connected intermittent generation) as opposed to traditional load. Additionally, the historical load profile is also becoming more variable, uncertain, and will tend to exhibit faster ramps than in the past because of behind-the-meter investments by loads in distributed energy resources (e.g., rooftop solar) and other assets that generally make loads less predictable ("BTM investments"). These challenges are not insurmountable, and as discussed further in section II below, ISOs/RTOs in the US and their stakeholders have recognized the issues associated with balancing net load and either taken or considered taking steps to address them. Some of the challenges associated with grid-connected intermittent resources and BTM investments are discussed below.

The variable and uncertain nature of grid-connected intermittent resources, which are not typically dispatchable, creates operational challenges because system operators must increase or decrease the generation output (or load reduction) from dispatchable resources to maintain the power balance and carry the required reserves. For example, both expected and unexpected changes in intermittent generation can happen quickly given the availability of solar and wind. This causes the net load that system operators must balance to change quickly, and these changes are often referred to as net load ramps. For example, the well-known California ISO ("CAISO") "Duck Curve" forecasts net load ramps as high as 13 GW within three hours as solar generation decreases with the sunset.[2] Unless actual loads decrease by the same amount and at the same time as solar generation – which they don't – the decline in solar generation must be replaced by other resources ramping up to balance the system's net load. Furthermore, due to the inherent unpredictability of wind and solar conditions, the generation output of intermittent resources – and thus net load – is also more uncertain than traditional load. System operators must manage new uncertainties associated with intermittent generation, many of which relate to weather (e.g., cloud cover and wind speeds, etc.) that did not require consideration in the past. This increased

[2] California ISO, *What the Duck Curve Tells us About Managing a Green Grid*, 2016, *available at* https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

uncertainty means that operators must respond, often quite quickly to *unforecasted* changes in net load in a manner that maintains the power balance and the minimum reserve requirement.

System reliability could suffer if the RTO/ISO operator doesn't have enough operational flexibility to balance net load and maintain the required reserves. This outcome is generally avoidable, however, because RTO/ISO operators generally operate their systems with a sufficient quantity of ancillary services to ensure that they can balance net load during the operating day. Presently, ISO/RTO operators will curtail the generation output of grid-connected intermittent resources during oversupply conditions if they lack the operational flexibility to accept and reliably balance this output. For example, during peak solar conditions in CAISO, the operator may have an oversupply of generation, which requires either reducing the generation of dispatchable resources or adding load to maintain the power balance. During such oversupply conditions, a CAISO operator may lack the operational flexibility to back down other dispatchable resources on the system (or increase loads from RTO/ISO demand response resources) and maintain the power balance. As a result, the operator may choose to curtail intermittent generation output. For example, CAISO is quite successful at integrating the output of grid-connected intermittent resources but still has to curtail about one percent of metered wind and solar generation.[3]

These challenges will become more acute in the near future as the existing thermal generation fleet retires and the majority of new resource investments in the US will be non-hydroelectric renewable resources like solar and wind. The US Energy Information Administration ("EIA") predicted in the January 2019 Short-Term Energy Outlook that non-hydroelectric renewable resources will be the fastest growing source of new generation capacity for at least the next two years. The EIA also projects that the share of total generation in the US from such intermittent resources will increase from 10 percent in 2018 to 13 percent in 2020.[4]

In addition to the challenges of integrating more grid-connected intermittent resources, ISO/RTO operators will also have to manage less predictable and faster-ramping loads from end users due

[3] Intermittent resource curtailments in CAISO tend to be highest in the Spring (March -May), and range from approximately 10 GWh in the summer months to over 60 GWh in the Spring California ISO, *Managing Oversupply*, accessed March 2019, available at http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

[4] U.S. Energy Information Administration, *Short-Term Energy Outlook*, January 2019.

to BTM investments. The term BTM investments is used herein to refer to resources that are not directly managed by or coordinated with the ISO/RTO. However, BTM investments affect end user loads. Distributed energy resources ("DERs") are BTM investments that are expected to significantly change end-user loads in some ISOs/RTOs, but other investments, such as plug-in electric vehicles (which can act as both DERs and a new load on the system) and other load control technology that is not coordinated with the ISO/RTO also have an impact. Currently, ISO/RTO operators may have a limited degree of information and awareness of the generation output of DERs,[5] but this should change over time as ISOs/RTOs create new operational protocols and data sharing. However, until that occurs, DERs and other BTM investments can generally make net loads more variable and less predictable. For example, the North American Electric Reliability Corporation noted in a 2017 report that "the effect of aggregated DER is not fully represented in [bulk power system] models and operating tools. This could result in unanticipated power flows and increased demand forecast errors."[6]

The combined effects of higher penetrations of grid-connected intermittent resources and BTM investments present ISO/RTO operators with a new challenge that generally has two dimensions: (1) reasonably foreseeable but faster net load ramps; and (2) and greater uncertainty about when net load ramps will occur and the speed/steepness of such ramps. As a result, ISOs/RTOs will need more operational flexibility to balance net load, and that flexibility will have to come from ISO/RTO managed or coordinated resources. This will require ISO/RTO market design changes because wholesale electricity markets were not originally designed to incent or reward resource flexibility. If these markets are not revised, ISO/RTO operators may have to get the flexibility they need through out-of-market actions, which can distort market outcomes (e.g., depress the clearing price).

The next section of this paper describes some of the approaches system operators have taken, or have considered taking, to procure and compensate resources for the levels of flexibility that will

[5] See e.g., PJM Interconnection, Distributed Energy Resources in PJM Transmission / Distribution Interface (April 2017) *available at* https://www.energy.gov/sites/prod/files/2017/04/f34/2_T-D%20Interface%20Panel%20-%20Mike%20Bryson%2C%20PJM.pdf at 5.

[6] North American Electric Reliability Corporation, *Distributed Energy Resources, Connection Modeling and Reliability Considerations* (February 2017) at *vi* available at https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

be required to balance the system as grid-intermittent resources are added to the system and as BTM investments increase. As a general matter, operators will require more operational flexibility from a more agile fleet of generation resources and dispatchable load resources than has occurred in the past.

II. ISO/RTO market mechanisms to increase operational flexibility

This section provides an overview of RTO/ISO market design and operational changes that have been adopted or considered to meet the operational challenges associated with reliably balancing a more uncertain and fast-ramping net load. These changes are generally designed to give operators more flexibility with which to balance net load. As discussed further below, several Federal Energy Regulatory Commission ("FERC")-jurisdictional ISOs/RTOs have recognized the need for additional operational flexibility in the future due to changes in loads and the generation mix. The solution adopted in each ISO/RTO will generally be tailored to meet the specific operational challenges in that ISO/RTO. Market design changes adopted in one ISO/RTO may not be appropriate in another.

A critical first step in procuring additional flexibility in wholesale electricity markets is defining what types of flexibility the system will need. Flexibility has many dimensions that are valuable to system operators in different ways, and each dimension must be considered before revising wholesale electricity markets to procure additional flexibility. Some of the key dimensions of resource flexibility are:

- supply offer for a dispatchable range (MW range between economic minimum and maximum operating levels)
- fast ramp-up and/or ramp-down (measured in MW/minute)
- fast start-up time (measured in minutes)
- fast shut-down (measured in minutes)
- low or zero minimum operating level (measured in MW)
- short minimum run time (measured in minutes)
- short minimum down time (measured in minutes)
- ability to start-up and shut-down multiple times per day

These dimensions of flexibility are offered to the ISO/RTO through the physical offer parameters of a given resource's energy supply offer and/or ancillary services offer. One of the most basic measures of resource flexibility is the willingness and ability to respond to economic dispatch signals from the system operator. Resources that submit dispatchable economic supply offers to the wholesale electricity market offer operational flexibility to the ISO/RTO because such resources can be dispatched up and down according to their economic offer to balance the system and/or provide reserves. By contrast, certain relatively inflexible resources, such as resources that cannot physically operate over a dispatchable range or respond to dispatch instructions (e.g., energy-limited resources such as hydroelectric resources that face operational restrictions) offer no dispatchable range to the system operator.

The speed at which a resource can respond to dispatch instructions – known as a resource ramp rate – constitutes another dimension of flexibility that is also highly valuable to system operators, particularly to manage both expected and unexpected net load ramps. Relatively quick start-up and shut-down times similarly give the system operator a greater ability to balance net load ramps by quickly dispatching resources up and down to balance net load ramps. Having a high minimum generation level generally places constraints on the operator, so a low minimum operating level is valuable to the system because such resources place a lower constraint on the system compared to a resource with a relatively high minimum operating level. Minimum run times are another important resource operating parameter that can add (or conversely remove) flexibility to the system.[7] Finally, a resource that can start-up and shut-down multiple times in a single operating day provides flexibility to the system operator.

The nature and quantity of the flexibility required in each wholesale electricity market will depend on the specifics of that system's expected net load. Ideally, additional resource flexibility would be procured through a market-based construct as opposed to through operator actions that take place outside of the market, which still impact market outcomes and clearing prices, but do so indirectly rather than directly. Such out-of-market actions can also distort market clearing prices. In order to increase operational flexibility, ISOs/RTOs will likely have to revise their

[7] For example, if the ISO/RTO only needs additional generation for the 30 minute peak period, it may prefer to commit and dispatch a resource with a 60 minute minimum run-time (unit A) than a resource with a six hour minimum run time (unit B) because the operator would have to back other online resources down to accommodate unit B's relatively high minimum generation level for the period's outside of the 30 minute peak period. At the very least, the system operator is no worse off if it has the choice between selecting between unit A or unit B.

markets to encourage and reward more flexible resource supply offers. This market redesign constitutes what economist call a "mechanism design" problem.

Generally speaking, designing a mechanism requires specifying an objective function and designing a system of payments and penalties (a mechanism) to achieve that objective. In designing that mechanism, due consideration must be given to understanding resource incentives and to the greatest extent possible, choosing market rules that encourage resources to invest in and maintain flexible resources. In the context of ISO/RTO markets, this means designing a system of payments and rules that encourage resources to submit flexible resource supply offers and offers to supply energy or ancillary services over a relatively short timeframe to the ISO/RTO by compensating them for doing so because resources can incur additional costs from offering flexibility (which is communicated through their energy supply offers) to the ISO/RTO. For example, frequent cycling can increase wear and tear on a resource and cause it to degrade faster. Additionally, operating at certain output levels, or configurations for a combined cycle unit, can be less efficient from a production standpoint and as a result, resource owners may prefer not to operate at those levels. Accordingly, it is critical that any ISO/RTO market changes that are designed to increase operational flexibility give resources the opportunity to recover the costs they incur from providing that flexibility. For example, in a December 2017 study of the impacts of a 50 percent penetration of renewable generation, the New York Independent System Operator ("NYISO") stated that "Operating characteristics such as availability, flexibility, and willingness to cycle are important to long-term grid stability and will need to be financially rewarded."[8] FERC-jurisdictional ISOs/RTOs have considered and/or adopted several market revisions or new mechanisms have been considered and adopted to increase resource flexibility. The following mechanisms are discussed in turn below: procuring additional reserves, flexible ramping products, and other market mechanisms to increase operational flexibility.

A. Procuring additional reserves

The ISO/RTO operator must maintain the system's frequency at 60 Hz and have secured in advance the ability to deploy the required level of reserves ("reserve requirement") if necessary.

[8] New York Independent System Operator, *Integrating Public Policy: A Wholesale Market Assessment of the Impact of 50% Renewable Generation*, December 2017, at 8.

ISO/RTO reserve requirements typically depend on the system's largest contingency (e.g., loss of the system's largest generator). The ISO/RTO's largest contingency is thus typically specified as a static figure throughout the year that does not vary with net load or net load uncertainty. However, as the nature of net load and the generation fleet change over time with higher penetrations of intermittent resources and BTM investments, the standard reserve product – a static MW quantity that typically depends on losing the system's largest generator – may no longer suffice to maintain the minimum reserve requirement with a high degree of confidence because fast or unexpected net load ramps can cause the ISO/RTO system to fall short of its required reserves.

Accordingly, one market-based means to enhance operational flexibility is to procure more reserves, both spinning and non-spinning reserves that are available within a short timeframe (e.g., 10 minute) and those that are available in a medium timeframe (e.g., 30-minute reserves). Procuring reserves has been recognized in academic literature as a means to increase operational flexibility.[9] Some ISOs/RTOs, including the PJM Interconnection ("PJM") and NYISO, have considered procuring additional reserves to address the operational challenges presented by changing net loads. In the instant proceeding (Docket No. EL19-58-000), PJM proposed, among other things, to revise its the operating reserve demand curve ("ORDC") based on operational uncertainties including – but not limited to – uncertainties associated with intermittent wind and solar generation.[10] One of the market concepts PJM proposed in Docket No. EL19-58-000 is discussed at a high level in section III below.

NYISO is also considering revisions to the amount of reserves it will procure on behalf of loads given the expectation that penetrations of intermittent generation and DERs will increase in NYISO in the future.[11] Specifically, NYISO stakeholders and staff, will consider changes to the

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[9] See e.g., E. Ela, M. Milligan, A. Bloom, A. Botterud, A. Townsend, T. Levin, and B.A. Frew, *Wholesale electricity market design with increasing levels of renewable generation: Incentivizing flexibility in system operations*, The Electricity Journal, Vol 29 (2016) at 52.

[10] PJM Interconnection, L.L.C., *Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C*, Transmittal Letter in Docket No EL19-58-000 (filed March 29, 2019) at 57. PJM specifically proposes to revise the ORDC based on uncertainties associated with errors in load forecasting, interchange forecasting, and generation performance and availability forecasting, which includes forecasting errors associated with wind and solar generation output.

[11] New York Independent System Operator, Market Design Concepts to Prepare, for Significant Renewable Generation, Ancillary Services Shortage Pricing: Market Design Concept Proposal, May 31, 2018, available at

NYISO ORDC to account, in part, for increased intermittent generation. NYISO staff recommended a stakeholder process to revise the ORDC in two key ways: (1) assign a non-zero value to reserves procured beyond the minimum reserve requirement with more gradual increases; and (2) revise administrative shortage pricing by increasing the penalty factors included in the ORDCs. As such, NYISO is considering ORDC changes that are similar in nature to the ORDC revisions PJM proposed in Docket No. EL19-58-000. With respect to valuing reserves procured beyond the applicable requirement, a NYISO staff presentation states that "including more gradual steps within the reserve demand curves could help to smooth unnecessary pricing volatility associated with increased renewable generation, while prices continue to appropriately reflect system conditions."[12] Similar to PJM's proposal in Docket No. EL19-58-000, NYISO is also considering creating a more granular reserve zone.

B. Flexible Ramping Products

Flexible ramping products were developed to address the dynamic nature of the need for resource flexibility and are designed to procure ramping capability from resources on a short-term basis. Flexible ramping products constitute a new category of ancillary services and are generally procured to address expected net load ramps and the uncertainty associated with those ramps. CAISO and the Midcontinent Independent System Operator ("MISO") currently have flexible ramping products and NYISO, Independent System Operator New England, and the Southwest Power Pool have discussed the merits of adopting a flexible ramping product with their stakeholders.

MISO was the first FERC-jurisdictional ISO/RTO to implement a flexible ramping product, which is referred to as a ramp capability product, in May 2016.[13] MISO's ramp capability product procures ramp capability from resources based on their ability to increase or decrease

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https://www.nyiso.com/documents/20142/1399291/Ancillary%20Services%20Shortage%20Pricing%20May%2031%20MIWG%20FINAL.pdf/fc2de5aa-380a-7d24-fa15-26bb463dfb96.

[12] NYISO, Market Design Concepts to Prepare for Significant Renewable Generation, May 31, 2018, at 9, *available at:* https://www.nyiso.com/documents/20142/1399291/Ancillary%20Services%20Shortage%20Pricing%20May%2031%20MIWG%20FINAL.pdf/fc2de5aa-380a-7d24-fa15-26bb463dfb96.

[13] *Midcontinent Independent System Operator, Inc.*, Order Conditionally Accepting Tariff Revisions, 149 FERC ¶ 61,095 (October 31, 2014).

their operating level within ten minutes. The ramp capability product is bi-directional (i.e., MISO can procure up- and down-ramp) and its procurement is co-optimized with energy and other ancillary services. Resources do not submit separate supply offers to provide this product. Instead, the ramp capability product market clearing price is based on the opportunity cost of not selling energy or other ancillary services. The system's demand for the ramp capability product is represented by a demand curve that reflects a $5/MWh maximum willingness-to-pay for ramp capability.[14]

To date, the market clearing prices for the ramp capability product in MISO and the flexible ramping product in CAISO are zero in most intervals, but non-zero prices have occurred. For example, in MISO, between December 2016 and February 2019, the weekly average "Up Ramp" market clearing price in the real-time market has never exceeded $0.40/MWh and the average Up Ramp price in the day-ahead market was at or below $1.40/MWh in all but one month.[15] In April 2019, real-time prices for upward ramping capability in MISO ("Up Ramp") were positive in 6.1% of the intervals, with prices ranging from $0.01/MWh to $5.00/MWh. The average Up Ramp price during the 237 real-time intervals in April 2019 with non-zero prices was $3.38/MWh and the average Up Ramp price for *all* real-time intervals (i.e., intervals with zero and positive clearing prices) was $0.21/MWh. The Down Ramp clearing price in MISO was zero in all real-time intervals in April 2019.[16]

CAISO also has a ramping product that was implemented in November 2016 and revised in February 2018 due to implementation errors.[17] CAISO's ramping product, referred to as a flexible ramping product, procures ramp capability based on a resource's ability to ramp up or down within the next five minutes and is co-optimized with energy and other ancillary service products. Similar to MISO, resources do not submit separate flexible ramping product offers and

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[14] *Id*. at P 7.

[15] Potomac Economics, *MISO Independent Market Monitor Quarterly Report: Winter 2019*, March 19, 2019, at 32.

[16] MISO, Market Data, March 2019 real-time Ex Post Ramp Capability Product Data available here https://docs.misoenergy.org/marketreports/201904_rt_expost_ramp_5min_mcp.xls.

[17] California ISO, Department of Market Monitoring, *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, April 18, 2018, at 3.

the market clearing price is based on the opportunity cost of not selling energy or other ancillary services. While MISO's ramp capability product is procured in both the day-ahead and real-time market, CAISO only procures its flexible ramping product in the fifteen-minute and real-time markets.

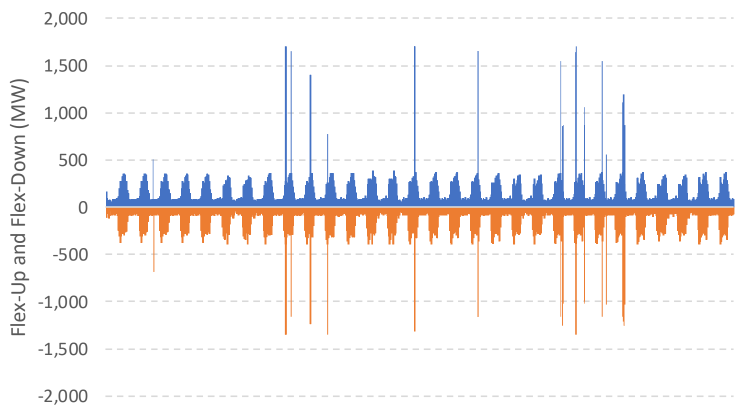
The demand curve for CAISO's flexible ramping product, which determines the quantity of flexible ramping capacity that the market buys, is more complex than MISO's ramp capability product. It is designed to value the trade-off between the cost of procuring additional ramp and the expected costs of violating CAISO's power balance constraint (currently $1,000/MWh). For each fifteen minute and real-time market interval, CAISO calculates "uncertainly requirements" based on an empirical distribution of recent errors in net load forecasts and the market optimization software satisfies that requirement though a combination of flexible ramp procurement and paying the price represented in the market demand curve for flexible ramp. The flexible ramping product demand curve has a maximum willingness-to-pay for up- and down-ramp of $247/MWh and $152MWh, respectively.[18]

In CASIO, after implementation errors were corrected in February 2018, aggregate CAISO expenditures on flexible capacity exceeded $1 million dollars per month, a trivially small percentage of total market costs, in only one month (April 2018) during the ten-month period between March and December 2018.[19] Figure 1 shows the quantities of ramp up ("Flex-Up") and ramp-down ("Flex Down) capacity that CAISO procured in April 2019. CAISO's Flex-Up and Flex-Down procurements follow a noticeable diurnal pattern every day, with spikes on certain days.

Figure 1: CAISO Flex-Up and Flex-Down Requirements, April 2019

[18] California ISO, Department of Market Monitoring, *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, April 18, 2018, at 3-5, and 38.

[19] California ISO, Department of Market Monitoring, *Q4 2018 Report on Market Issues and Performance*, February 13, 2019, at 47.



Source: CAISO OASIS, accessed May 2019.

The average quantity of Flex-Up and Flex-Down procured in the CAISO system in April 2019 was approximately 176 MW, with a maximum of 1,701 Flex-Up procured and a maximum of 1,349 MW of Flex Down procured.[20] Despite procuring non-zero quantities of Flex-Up and Flex-Down in April 2019, the market clearing price for both of CAISO's flexible ramping products was zero in every real-time interval. However, in the Energy Imbalance Market ("EIM") in April 2019, the Flex-Up price was non-zero in 1.3% of the intervals in the fifteen-minute market for the EIM as a whole and in 0.7% of intervals in the Arizona Public Service area.[21]

C. Ramping product versus procuring additional reserves

Procuring additional reserves and introducing a flexible ramping product are both market design changes that can increase ISO/RTO operational flexibility. The two approaches are similar in many respects and different in others, and it is instructive to understand how the two compare. As an initial matter, additional reserves and upward ramping capability are very similar ancillary service products because both products generally hold the capability to generate electricity within a short operational timeframe in reserve based on the expectation that it may need to be

[20] CAISO OASIS Database, Accessed May 1, 2019.

[21] In April 2019, the Flex-Down price was non-zero in 0.4% of the fifteen-minute market intervals in the EIM Area and in 0.3% of intervals in the Arizona Public Service area. The monthly average EIM Area Flex-Up and Flex Down prices in the fifteen-minute market in April 2019 were $1.52/MWh and $0.14/MWh, respectively. Other areas of the EIM had non-zero Flex-Up and Flex-Down prices in fewer than 0.1% of the fifteen-minute market intervals in April 2019.

deployed in future periods. The distinction is one of classification - one product is classified as reserves, the other as ramp capability - but not necessarily of function or capability. Provided that both ramping capability and additional reserves are equally eligible to be deployed and converted into energy if needed,[22] additional reserves and upward ramp capability provide a similar, if not identical, service to the RTO/ISO operator. Both enhance operational flexibility. As noted above the, CAISO flexible ramp product procures capacity that can be converted into energy within five minutes, and the MISO ramp capability product procures capacity that can be converted into energy within ten minutes. As such, revising the ORDC to procure additional reserves and implementing a flexible ramping product constitutes a market-based mechanism that provides ISO/RTO operators with similar "insurance" against falling short of the reserve requirement and helps operators manage net load ramps and uncertainty by holding some generation capability in reserve to address the risk of being short energy or reserves in future time periods.

Additionally, both approaches dispatch system resources differently compared to a more traditional/historical dispatch that generally holds back, or "postures", certain resources from generating energy in the current period based on the expectation that those resources may be needed to provide energy in future periods. Finally, additional reserves and flexible ramping products are co-optimized with energy and other ancillary services prices and generally have market clearing prices that are based on the marginal resource's opportunity cost of not selling energy.[23] This opportunity-cost based pricing structure for reserves and flexible ramping capacity explicitly recognizes the substitutability between generating energy and providing reserves or ramping capability.

Procuring additional reserves and creating a separate ramping product are also different in several respects. One key difference is the separate "ramp price" associated with a flexible ramping product. Revising the ORDC to purchase additional reserves creates a single price for

[22] The circumstances under which reserves can be used to manage net load ramps is important but can be ambiguous in some ISO/RTO tariffs and protocols. In Order No. 764, the Commission declined to provide guidance on the appropriate use of contingency reserves under NERC reliability standards. The Commission found that the issue needed "further study and vetting" before any action was considered. See *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 (June 22, 2012) at P 342.

[23] See e.g., PJM Transmittal in Docket No. EL19-58-000 at 83-84.

that reserve product whereas ISOs/RTOs that have both traditional reserves and flexible ramping products produce separate prices for each ancillary service product.

Another difference between procuring additional reserves and creating a separate ramping product is the fact that ramping products are bi-directional and thus address net load ramping issues in both the upward and downward direction. Procuring additional reserves, which as explained above, was traditionally designed to replace lost generation associated with the system's largest contingency only procures upward ramping capability within the timeframe specified by the associated reserve product (e.g. energy available within 10-minutes or 30-minutes). As such, ISO/RTO market changes that revise the ORDC do not address issues associated with negative net load ramps.

However, a given ISO/RTO may experience fewer operational issues with negative net load ramps than with positive net load ramps. This could occur, for example, if ISO/RTO operators tend to have sufficient downward ramp capability from the existing fleet of resources but insufficient upward ramp capability. There is evidence to suggest that this may be the case in MISO because Up Ramp prices tend to be higher than Down Ramp prices, which suggests the upward ramping constraint MISO uses to procure its ramp capability product binds more often and at higher prices than the downward ramping constraint. Accordingly, a ramping product could be needed in some ISOs/RTOs and not in others. As discussed further below, ISO-NE and NYISO both led stakeholder processes that considered adding a separate flexible ramping product but appear to have decided not to do so at this time.

Another difference between revising the ORDC and creating a separate flexible ramp product is that the shape of the ORDC is generally established further in advance as compared to the demand curves used to procure flexible ramping products. As noted above, the demand curves CAISO uses to determine the quantities of Flex-up and Flex-down flexible ramping capacity are based on forecast errors experienced during the preceding 30 days, whereas an ORDC would not generally be updated on such a frequent basis. For example, although PJM proposed to use 24 separate ORDCs to account for seasonally and within-day operational needs, those curves would be updated annually based on system experience in the preceding three years.[24]

[24] See e.g., PJM Transmittal in Docket No. EL19-58-000 at 60-61.

D. Other means to procure flexibility

There are several other means to increase operational flexibility in a manner that helps ISO/RTO operators integrate higher penetrations of grid-connected intermittent resources and BTM investments. For example, Hybrid resources that collocate intermittent generation with electric storage resources can also smooth out net load ramps caused by the intermittency of wind and solar resources and make the hybrid resource capable of responding to operator dispatch instructions. Demand-side resources and price-responsive loads can also address net load ramps. However, coordinated price responsive demand programs that are known to and dispatched by the load serving entity or ISO/RTO are generally more valuable, particularly for planning purposes, than BTM investments such as price responsive load that is not formally coordinated with the load serving entity or ISO/RTO.

Improved load and weather forecasting will also help ISO/RTO operators balance net load in the future because more precise forecasts generally reduce uncertainty, but that uncertainty cannot be eliminated entirely. ISOs/RTOs could also consider revising their current regulation products or adding a fast frequency response product, which creates a new category of frequency regulation that can respond fully to operator instructions on a faster timescale. For example, the Electric Reliability Council of Texas will add a fast frequency response contingency reserve product capable of responding in full within 15 cycles of operator instruction after January 2022.[25] Clearing the day-ahead market on a 15-minute basis rather than hourly can also help manage net load ramps because resource day-ahead schedules can be better matched with expected net loads, but increasing the granularity of the day-ahead market optimization adds to the solution time. However, computational advances can make this less of a concern in the future.

A financially-binding, multi-day unit commitment process can also help ensure that the dispatchable resources needed to balance net load will be online and available when needed to serve net load, including expected and unexpected net load ramps. Finally, larger balancing areas that encompass more resources and peak load diversity can also help balance net load ramps and

[25] See e.g., Electric Reliability Council of Texas, *Nodal Protocol Revision Request Number 863 – Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve*.

uncertainty. For example, the Energy Imbalance Market in the West can help CAISO balance the intermittent wind and solar generation on its system.

Adding a flexible ramping product or procuring additional reserves by revising the ORDC generally addresses the ISO/RTO's short-term needs for operational flexibility by providing resources with incentive to respond to operator dispatch instructions by paying those resources based on the opportunity cost of the marginal resource. As such, the marginal resource would generally be indifferent between providing reserves or ramping capability and providing energy. However, market designs that procure more reserves or add a flexible ramping product, both of which are components of the energy and ancillary services markets, may not enable a resource to recover the fixed costs of maintaining its existing flexible capability or stimulate investment in new flexible capability.

Currently, CAISO is the only ISO/RTO in the US that procures flexible capacity forward on a longer-term basis in a manner that enables resources to recover their fixed costs. The CAISO Flexible Resource Adequacy product is part of the California Public Utility Commission's Resource Adequacy program, which requires jurisdictional load serving entities to procure system, local, and flexible capacity for a given annual delivery period.[26] Each jurisdictional load serving entity has a Flexible Resource Adequacy requirement the specifies the amount of flexible capacity that load serving entity must procure. This requirement can only be met with capacity that can be made available to CAISO within 3 hours of deployment.

III. PJM's proposal to procure more reserves

This section focuses more generally on the concept in PJM's proposal in Docket No. EL19-58-000 to revise the ORDC and procure more reserves, which is a reasonable approach to manage the operational challenges associated with net load ramps and uncertainty. As described further below, these operational challenges are only expected to increase in the future as installed grid-connected intermittent capacity increases and BTM investments increase. Furthermore, the Commission approved market design changes to address the operational challenges presented by

[26] California Public Utilities Commission, *The 2017 Resource Adequacy Report*, August 2018, at 5. On a month-ahead basis, jurisdictional load serving entities must demonstrate to the California Public Utility Commission that they have procured their monthly system and flexible resource adequacy obligation. For the months of July through December, those LSEs must demonstrate they have met their local resource adequacy obligation.

net load ramps and uncertainty when it approved flexible ramping products in CAISO and MISO that permitted both ISOs to procure upward ramping capability beyond the reserve requirements in each respective ISO and assign a non-zero value to that capability. Therefore, given the similarities between upward ramping capability and traditional reserves noted above, approving a market design change that generally revises the ISO/RTO ORDC to procure reserves beyond the system's reserve requirement would be consistent with market designs the Commission has already approved.

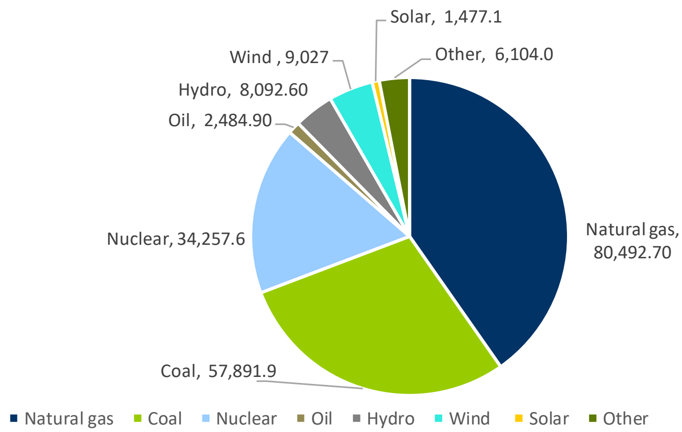
As described above, reserves procured beyond the reserve requirement have value to the ISO/RTO and its loads because the reserves give operators additional operational flexibility to balance net loads. Revising the ORDC is also easier to implement because it builds on an existing market product as opposed to creating a new ancillary services product. Revising the ORDC as opposed to creating a separate flexible ramping product can also be more consistent with a system's operational needs at a given time than a ramping product. For example, ISO New England ("ISO-NE")[27] and NYISO both held stakeholder processes that considered the merits of ramping products. However, neither ISO appears to have plans to propose a flexible ramping product to FERC in the near future, which suggests that both ISOs and their stakeholders have determined that ramp products are not needed at this time. As noted above, in the near-term, NYISO plans to consider changes to ORDC and shortage pricing practices instead. Of course, these determinations could change in the future.

Focusing specifically on the operational needs on PJM, two trends will drive net load ramps and uncertainty: 1) increased grid-connected intermittent generation; and (2) more variable loads due to DERs and BTM investments. Figure 2 below shows the composition of the PJM generation fleet that was in service at the end of 2018.[28] Natural gas capacity of various types made up 40.3% of installed capacity, and coal and nuclear represented 29% and 17%, respectively. Wind and solar combined made up 5.3% of the installed capacity, but, as described further below, the proportion of these grid-connected intermittent resources is expected to increase over time.

[27] *See e.g.*, ISO England, Procurement and Pricing of Ramping Capability – Technical Session 3, March 20, 2018, *available at* https://www.iso-ne.com/static-assets/documents/2018/03/price_information_technical_session3.pdf

[28] *Monitoring Analytics*, *2018 State of the Market Report for PJM*, "Table 12-2 Existing PJM capacity: December 31, 2018 (By state and unit type (MW))" at 570.

Figure 2: Existing PJM capacity in Dec. 2018

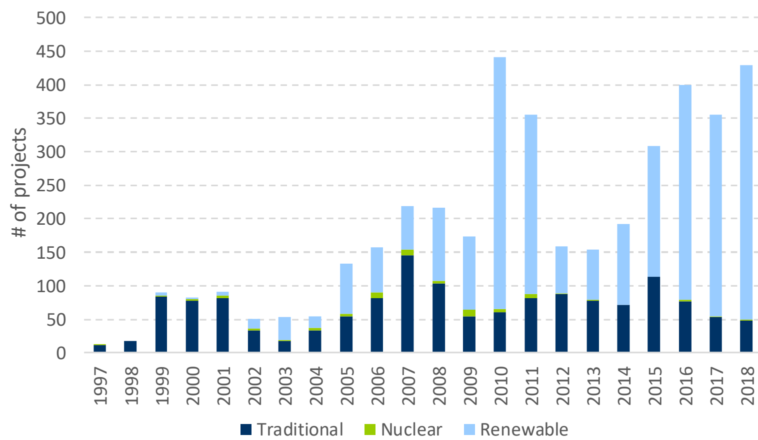


Source: Monitoring Analytics, 2018 State of the Market Report for PJM, at 570.

PJM's generation mix is expected to change in the future as new generation capacity is added and existing generation retires. The PJM interconnection queue gives an indication of the resources that will be in service in the PJM footprint in the next few years. Although only a fraction of the generation facilities submitted into PJM's interconnection queue actually get built, the PJM Independent Market Monitor found that 82% of the 1,492 projects entered into the queue during the 2015- 2018 time period were renewable projects.[29] Figure 3 below shows how the fuel type of projects entered in to PJM's interconnection queue has evolved over time.

[29] Id. at 582.

Figure 3: Projects entered into the PJM interconnection queue as of December 2018



As shown, in Figure 3, renewable projects become the dominant fuel type in the interconnection queue in a trend that started in the mid-2000s. In May 2019, wind and solar projects made up 45% of the nameplate capacity in PJM's interconnection queue of projects with an active, suspended, or under construction status.[30] Furthermore, a portion of PJM's existing thermal generation fleet will retire, which is not expected to create significant reliability issues[31] but will nonetheless change the composition and attributes generation fleet that are available to PJM operators. For example, the PJM Independent Market Monitor notes that 13,398 MW of generation have requested to retire on or after January 1, 2019, which constitutes 6.7% of PJM's 199,489 MW fleet.[32]

Several states in the PJM footprint have adopted policies to increase DERs, including Maryland, Pennsylvania, and Virginia.[33] Many of these states also have programs to promote plug-in

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[30] *See* https://www.pjm.com/planning/services-requests/interconnection-queues.aspx, accessed May 1, 2019.

[31] PJM Fuel Security Study, December 2019.

[32] Monitoring Analytics, *2018 State of the Market Report for PJM*, at 563.

[33] Cites.

electric vehicles and new charging stations.[34] As noted above, DERs and other BTM investments will tend to make net loads more uncertain and thus difficult to forecast.

Taken together, higher penetrations of grid-connected intermittent resources and BTM investments in the PJM footprint are expected to result in net loads that are characterized by faster and steeper ramps and greater uncertainty. Given that both trends are expected to increase over time, the operational challenges PJM operators face will also increase. Therefore PJM, like other ISOs/RTOs in the US, will need more operational flexibility in the future. PJM's general proposal to revise its ORDC and procure reserves beyond the minimum reserve requirement and assign a non-zero value to those reserves is a just and reasonable approach to address the challenges associated with an increasingly variable and uncertain net load and will allow PJM operators to use a market-based mechanism to procure operational flexibility instead of the out-of-market approach operators currently employ.

[34] See e.g., Maryland Public Service Commission, Notice of Initiating A Proceeding and Request for Comments. Case No. 9478. (ML 218878), issued February 6, 2018.