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Refining competitive electricity market rules to unlock flexibility

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ABSTRACT

Competitive electricity markets are undergoing a rapid transformation from systems with large, inflexible baseload resources to ones with smaller, modular, variable resources. Making the grid more flexible is critical to enabling a smooth transition. A significant amount of unused flexibility exists in the system today, but harnessing it requires changes to market rules.

1. Introduction

Competitive markets for electricity, or regional transmission organizations (RTOs), are at an inflection point. When RTOs were first created in the United States during the 1990 s, founders designed operations and practices around the technical elements of the grid of that time. Grid operators dispatched large central station generators to follow inflexible load, with power flowing in one direction from these central generators out to customers. RTOs managed the scheduling and dispatch of these generators, ensuring they met relatively predictable demand. While this system and its concomitant rules, procedures, and definitions has worked well for the last 20 years, it is becoming increasingly strained as the grid modernizes.

2. Flexibility for an evolving electricity grid

Today's grid is evolving in at least four ways due to new innovation and cost breakthroughs in technologies like wind, solar, batteries, and information technology (IT). First, RTOs have to plan for predictable variations in supply in new ways. While managing a predictable decrease in supply is nothing new for RTOs (think of a nuclear unit refueling, for example), RTOs now have to do this on a daily basis with an increasingly large pool of resources whose output varies on shorter and more frequent timescales. For example, in a region with plentiful solar power, grid operators have to manage the decrease in output from solar in the evenings and ensure sufficient alternative resources are available to dispatch.

Second, RTOs also have to manage the unpredictable variations in supply associated with higher penetrations of variable resources. As with managing predictable variations, managing unpredictable variations is not new to grid operators. RTOs have managed the grid around contingency events, such as the loss of a generator or transmission line, for decades. However, with growing levels of variable renewables, the sources and degrees of variability have increased. Some of this increase is offset, however, by the fact that historically, unpredictable variations were often the result of large generator failures. The unpredictable variation in output from renewables, on the other hand, tends be much more modular and not highly correlated across resource types, meaning the unpredictable variations will be smaller in magnitude and tend to balance each other out when compared to the historical paradigm of large generator failures.

Third, grid operators must manage the bulk electricity system (i.e. the transmission system, the domain over which they have control) with increased output coming onto the grid from distributed energy resources (DERs), like rooftop solar. With little visibility into and little control over the types and amounts of resources on the distributed system, RTOs are facing new challenges in accurately forecasting net demand.

Fourth, innovations in load resources are creating vast new opportunities for RTOs or load suppliers to harness the flexibility of load as a valuable resource. From advanced vehicle charging to electric water heaters that together can act as a giant distributed battery, RTOs increasingly are able to dispatch load resources to balance supply and demand.

Successfully managing a modern grid comes down to ensuring the grid is flexible enough to handle the characteristics of new resources and capitalize on their capabilities to the benefit of customers. Flexibility comes in many forms, but broadly, it means the ability to respond over various time frames – from seconds to seasons – to changes in supply, demand, and net load. The more flexible the power

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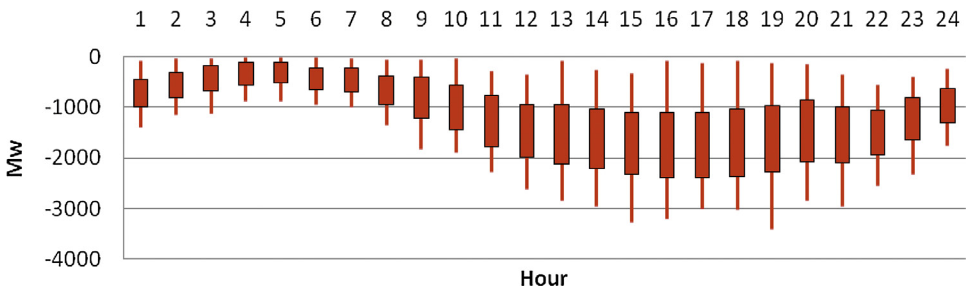

Fig. 1. CAISO summer downward 5-minute capability, limited by self- schedules, 2009 and June 2010. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS" (Folsom, CA: California ISO, August 31, 2010), Fig. 4-2.

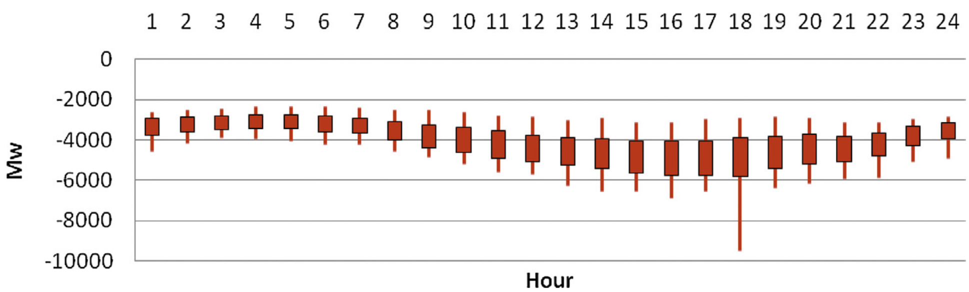

Fig. 2. Summer downward 5-minute capability of thermal units, not limited by self-schedules, 2009 and June 2010. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS" (Folsom, CA: California ISO, August 31, 2010), Fig. 4-3.

system, the easier it is for grid operators to manage the system around variable supply and demand. As the system becomes increasingly modular and renewables-based, ensuring sufficient grid flexibility is key to operating the grid reliably and minimizing costs.

3. Refining market rules to unlock the flexibility of existing resources

Fortunately, significant amounts of latent flexibility exist in the grid today. Tapping into unused flexibility available on the grid requires updates to market rules – restrictions, exceptions, definitions of resources, and technology requirements – around which the system was originally designed. Many of the RTOs in the U.S. are already tackling some of these changes, with a noticeable increase in the amount of flexibility on the grid and improved ability to integrate renewables. However, RTOs can tap the tremendous wealth of additional flexibility potential by increasing the share of resources that participate in economic dispatch, improving price signals, removing barriers to resources participating in markets, and better aligning natural gas markets with electricity markets.

3.1. Require all generators and imports to participate in economic dispatch

Most RTOs allow resources to choose between being dispatched based on the market price of energy, or to schedule resources to dispatch regardless of price as "self-scheduled" price-takers. Resources might choose to self-schedule for several reasons.

First, resources with very low or zero marginal costs may choose to self-schedule because the market clearing price will never fall below their marginal production costs. For example, a merchant wind plant built in 2016 receives a $23 per megawatt-hour (MWh) production tax credit and has zero operational costs, meaning it will make money so long as the energy market price is above -$23/MWh. Because the energy market-clearing price will usually be more than this price, the wind plant can just self-schedule rather than respond to price signals.

Second, resources may choose to self-schedule if the penalties for generating during times of congestion are not sufficiently high. In other words, if the market price floor is too high, generators will not have an incentive to reduce production. Consider a market with a minimum bid price of $0. In this case, even if the same wind generator described above submitted an offer curve, it would never ramp down production; at $0 and with the production tax credit, the generator is still profitable. All U.S. markets currently allow negative prices, though some are reconsidering whether or not to restrict minimum bids to $0. Of course, lowering the price floor can simply penalize resources without improving market efficiency. If resources are physically unable to respond and change output in response to prices, then further lowering the floor will simply fine them for inflexibility. RTOs should therefore conduct careful analysis before deciding to lower the price floor.

Third, a resource may choose to self-schedule if its contract terms are inflexible and require guaranteed delivery. For example, roughly half of the California Independent System Operator's (CAISO) power imports are on fixed schedules and do not participate in economic dispatch.[1] As another example, natural gas generators sometimes have to secure gas supply ahead of when they need it, and may schedule themselves (or may be forced to by the gas company) into the market to ensure generation to match their supply (this is discussed in more detail in Section 3.3).

Finally, generators might have physical reasons for self-scheduling. For example, hydro plants may choose to self-schedule due to water management and environmental functions other than providing electricity. In other instances, for example with some nuclear plants, a resource may be physically incapable of responding to dispatch signals and therefore choose to self-schedule.[2]

Self-scheduling removes some resources from the economic dispatch that could provide flexibility if those resources relied on price signals from the market to decide when to run, regardless of price signals and conditions on the grid (barring emergency conditions). For example, a hydro plant responding to price signals could provide a significant amount of flexibility, but if it is self-scheduled, it is unable to do so

[1] "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS" (Folsom, CA: California ISO, August 31, 2010), 84.

[2] E. Ela et al., "Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation."

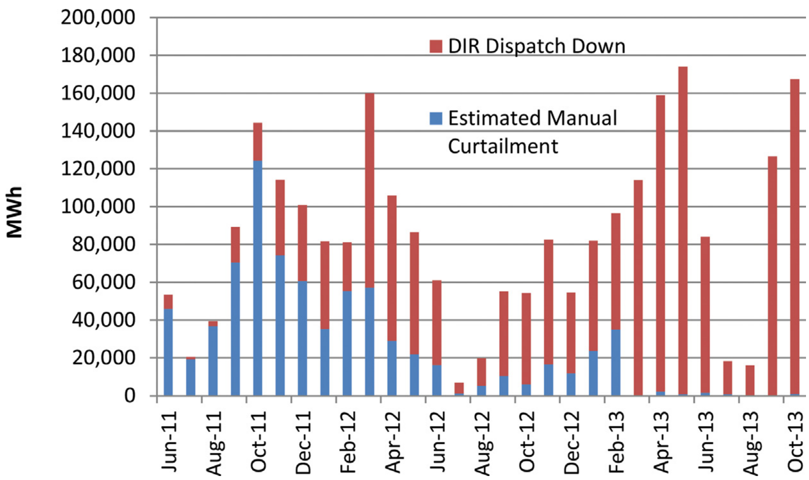

Fig. 3. Manual curtailments nearly eliminated with DIR category in MISO. Lori Bird, Jaquelin Cochran, and Xi Wang, "Wind and Solar Energy Curtailment: Experience and Practices in the United States" (Golden, CO: National Renewable Energy Laboratory, March 2014), Fig. 3, http://www.nrel.gov/docs/fy14osti/60983.pdf.

(though it may have physical reasons for self-scheduling).

Though self-scheduling may be an appropriate tactic if physical limitations exist, as in the hydro plant example above, excessive self-scheduling results in the loss of a significant amount of system flexibility.

For example, Figs. 1 and 2 show the results of an analysis conducted by CAISO that examined the load-following capability of the fleet under a scenario with 20% renewables. Fig. 1 shows the down ramp capability of the fleet, accounting for self-scheduled resources. On most days, the down ramp capability ranges between 0–3,000 MW. Fig. 2 shows the down ramp capability assuming that all resources are dispatchable (i.e. not self-scheduled).[3] In this scenario, down ramp capability ranges between 2,000–5,000 MW. Thus, self-scheduling in this scenario removes about 2000 MW of potential flexibility from the market.[4]

To address the flexibility and grid operation challenges created by self-scheduling, grid managers should require all resources, including variable generators and imports, to participate in economic dispatch unless the resource has a verifiable physical incapability of adjusting output.

Several RTOs including the Midcontinent Independent System Operator (MISO), the New York Independent System Operator (NYISO), and the Electric Reliability Council of Texas (ERCOT) require wind generators to submit price curves rather than self-schedule. This requirement allows wind plants to be economically dispatched down, providing operators with additional flexibility if it is needed.

Including renewables as part of economic dispatch rather than manually curtailing them is especially important given the revenue structure for many renewable resources. For example, most wind units currently receive a production tax credit of $23/MWh, and many of these units will also generate renewable energy credits (RECs) worth as much as $50/MWh (and many times this much for solar units in some regions).[5] If these units are not included in economic dispatch, operators can manually curtail them even when doing so causes significant financial harm. To be sure, contract structures for renewables need to build in an acceptable level of economic curtailment, and many already do.[6] Transitioning these resources to economic dispatch can ensure that renewable units are only dispatched down when doing so minimizes overall system cost, while also compensating them for following dispatch signals. MISO's Dispatchable Intermittent Resource (DIR) class is a particularly successful example of how variable generators can effectively be integrated into economic dispatch.

3.1.1. Example: MISO Dispatchable Intermittent Resource

MISO's DIR category is a successful approach to integrating variable renewables into energy markets. Prior to the implementation of DIR in MISO, a significant amount of self-scheduled wind capacity contributed to transmission congestion. With no way to economically curtail wind during times of congestion, grid operators were forced to manually call wind operators and tell them to turn off. Not only is this inefficient from a grid optimization standpoint, but it fails to consider the differential costs of curtailment to different wind plants and can create challenges for developers trying to finance new plants.[7]

MISO introduced the new DIR resource designation in 2011 as a way of integrating previously self-scheduled wind resources into economic dispatch in the wholesale market. The DIR designation requires wind plants to be equipped with technology allowing them to follow a dispatch signal and requires them to bid into the day-ahead and real-time markets. DIRs contribute to price formation (they can set the locational marginal price[8]) whereas they were previously incapable of doing so.[9] DIRs, like other generators that participate in price formation, are also eligible to receive uplift or make-whole payments. In particular, the Day-Ahead Margin Assurance Payment (DAMAP) guarantees profit equivalent to that received in the day-ahead market when dispatch in the real-time market is below the scheduled amount of dispatch in the day-ahead market.[10] Therefore, wind plants are incented to follow dispatch signals and provide flexibility to operators (Fig. 3).

The DIR has very successfully reduced manual curtailments in MISO. For example, prior to the full implementation of DIR, MISO averaged between 1,000–2,000 manual curtailments per year, with a 3.7% curtailment rate in 2010. With the creation of the DIR, manual

[3] All thermal resources are assumed dispatchable, so the change in the graph comes from making renewables (including hydro, geothermal, and biomass) dispatchable.

[4] "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS."

[5] Note that the renewable energy production tax credit will decrease by 60% through 2019 and subsequent years.

[6] Eric Gimon, Robbie Orvis, and Sonia Aggarwal, "Renewables Curtailment: What We Can Learn From Grid Operations in California and the Midwest," *Greentech Media*, March 23, 2015, https://www.greentechmedia.com/articles/read/renewables-curtailment-in-california-and-the-midwest-what-can-we-learn-from.

[7] Lori Bird, Jaquelin Cochran, and Xi Wang, "Wind and Solar Energy Curtailment: Experience and Practices in the United States" (Golden, CO: National Renewable Energy Laboratory, March 2014), 11, http://www.nrel.gov/docs/fy14osti/60983.pdf.

[8] The locational marginal price, or LMP, is the market-clearing price for electricity a supply a particular node on the electricity system (point of interconnection to the transmission system). LMPs (LBMPs in NYISO) are how market operators calculate the differential locational price of electricity supply across the transmission system

[9] Michael Kessler, "Re: Midwest Independent Transmission System Operator, Inc. Electric Tariff Filing Designating Dispatchable Intermittent Resources FERC Docket No. ER11-___," November 1, 2010, https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2010-11-01%20Docket%20No.%20ER11-1991-000.pdf.

[10] "MISO Make-Whole Payment Overview" (PJM Energy Market Uplift Senior Task Force, PJM, December 2014), 11.

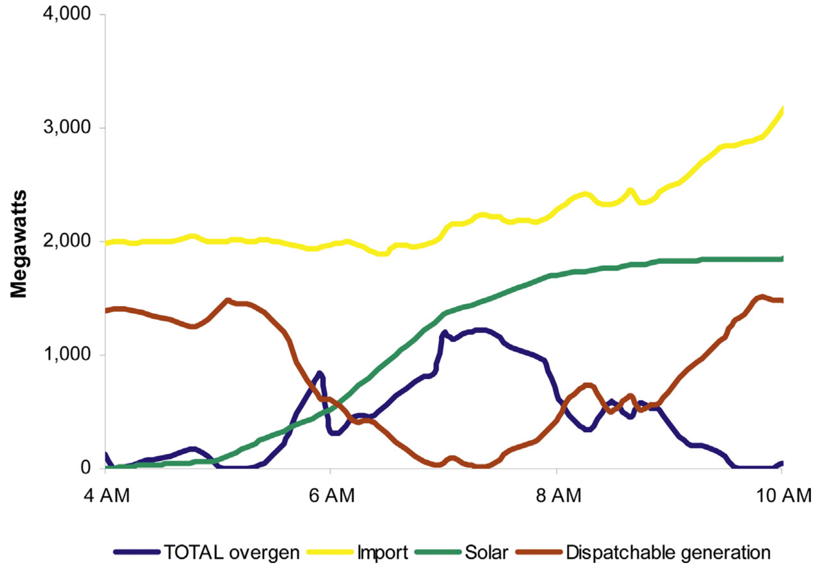

Fig. 4. Dispatchable generation and overgeneration in CAISO. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS" (Folsom, CA: California ISO, August 31, 2010), Fig. 5-4.

Fig. 5. Volume of annual overgeneration (GWh) in three sensitivity cases. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS" (Folsom, CA: California ISO, August 31, 2010), Fig. 5-9.

curtailments in MISO have decreased to almost zero. Because units are rewarded for dispatching down, wind units can now economically participate in wholesale markets and no longer are incented (or allowed) to self-schedule. This effort should be expanded to all resources physically capable of adjusting output.

Similar requirements are in place in NYISO, where wind generators are required to bid into energy markets and respond to dispatch signals. However, NYISO excludes wind resources from receiving make whole payments like the DAMAP mentioned above, and therefore puts wind resources at a disadvantage relative to other generators.[11]

3.1.2. *Including imports in economic dispatch*

Electricity imports should also be included in economic dispatch. In some markets, electricity imports can compose a significant amount of the energy used to meet load. For example, CAISO imported 110 TW-hours (TWh) of electricity out of a total of 295 TW h needed to meet load in 2015, which means imports made up more than 37% of total electricity.[12] Imports can be highly valuable for grid managers, and in many instances, expanding ties with neighboring regions diversifies the resource mix and improves the flexibility of the grid.

However, to achieve the diversity and flexibility benefits of imports, they must operate dynamically. Problems can arise when imports are self-scheduled, instead of operating flexibly based on market conditions. For example, CAISO can experience a significant amount of over-generation as solar begins to generate in the morning and some imports are not incented to ramp down (Fig. 4). Inflexibility from imports results in in-state dispatchable generation being ramped down along with renewable curtailments. In CAISO, as much as half of imports are self-scheduled.[13],[14], [15]

Reducing self-scheduled imports can have a dramatic impact on curtailment of renewable energy. For example, CAISO studied the impact on over-generation at different levels of import self-scheduling, and found that reducing self-scheduled imports from 100% to 75% resulted in nearly a 75% reduction in the amount of over-generation (Fig. 5).

In regions with growing or already significant shares of imports, these imports must be required to participate in economic dispatch.

3.2. *Preserve negative pricing in energy markets*

The ability to offer negative prices in energy markets is important to

[11] FERC, Order Accepting Tariff Revisions, No. ER09-802-000 (May 11, 2009).

[12] Note that this value can change dramatically depending on the amount of in-state hydro capacity available in a given year. However, imports are usually a significant part of supply used to meet load. See: California Energy Commission, "California Electrical Energy Generation," n.d., http://www.energy.ca.gov/almanac/electricity_data/electricity_generation.html.

[13] "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS," 84.

[14] Ibid., fig.' 5-4'.

[15] Ibid., fig.' 5-9.

Table 1
Bid floors in US RTOs.

Market	Bid Floor
CAISO[a]	-$150/MWh
PJM[b]	None
ERCOT[c]	-$250/MWh
MISO[d]	-$500/MWh
NYISO[e]	-$1,000/MWh
ISO-NE[f]	-$150/MWh
SPP[g]	-$500/MWh

[a] CAISO, "Fifth Replacement FERC Electric Tariff," July 10, 2017, sec. 39.6.1.4, https://www.caiso.com/Documents/ConformedTariff_asof_Jul10_2017.pdf.

[b] "PJM Open Access Transmission Tariff," July 1, 2017, sec. Attachment K, 1.10.1A(d)(viii), http://www.pjm.com/directory/merged-tariffs/oatt.pdf.

[c] ERCOT, "ERCOT Nodal Protocols: Section 4: Day-Ahead Operations," July 1, 2016, sec. 4.4.9.5.1 (2), http://www.ercot.com/content/wcm/current_guides/53528/04_070116_Nodal.doc.

[d] MISO, "MISO Tariff," August 21, 2017, sec. Generation Offer and Demand Response Resource Type-II Offer Rules in the Day-Ahead Energy and Operating Reserve Market (f)(ii), https://www.misoenergy.org/_layouts/MISO/ECM/Download.aspx?ID=169,142.

[e] NYISO, "NYISO Tariff," August 1, 2017, sec. Attachment AE, 21.4, https://nyisoviewer.etariff.biz/ViewerDocLibrary//MasterTariffs//9FullTariff.pdf.

[f] ISO-NE, "ISO-NE Tariff Section I - General Terms and Conditions," June 1, 2017, 33, "Energy Offer Floor," https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf.

[g] SPP, "SPP Tariff," July 12, 2017, sec. Attachment AE, 4.1.1 (5), https://www.spp.org/Documents/52372/SPP%20OATT_20170712.zip.

effectively operating the grid, and negative prices don't deserve their bad rap. Units may choose to offer negative prices if they receive out-of-market compensation, for example RECs or production tax credits. In many instances, units with other revenue streams may find it profitable to continue to operate, even if energy prices drop to zero or below zero.

Allowing units to offer prices below zero provides at least two valuable inputs to grid operators. First, when prices drop below zero, grid operators can determine which units should be dispatched down ahead of others. If the minimum bid price is set to zero and many other resources are providing offers of zero, grid operators would not be able to determine which units to dispatch down ahead of others. Much like the MISO DIR example discussed above, this can lead to a situation where grid operators have to manually call units to dispatch down, inhibiting market efficiency and raising overall costs.

Second, negative pricing helps provide investment signals for new storage resources to help manage local over-generation from variable resources or transmission constraints. For example, at negative clearing prices, storage can earn revenue by absorbing excess power (the reason for negative prices) and reselling that power to the grid at another time, arbitraging the price difference. This can be particularly valuable for simultaneously addressing over-generation and ramping concerns in regions with high penetrations of solar power. Negative prices also help to highlight areas where additional transmission investment is needed.

Although all U.S. RTOs currently allow units to offer negative prices into the day ahead and real time energy markets, at least one RTO, PJM, is considering eliminating negative prices[16], while the U.S. Department of Energy (DOE) has suggested, in a highly politicized report, that negative offer prices should be eliminated.[17]

The rationale for these proposals is concern over the impact of negative pricing on market prices and revenues for other generators. However, negative pricing has had very little impact on average market prices, a point confirmed by DOE in its report suggesting negative pricing should be eliminated.[18] Table 1 summarizes the bid floors in U.S. RTOs.

3.3. *Increasing flexibility through better natural gas and electricity market coordination*

Today's electricity grid relies heavily on natural gas units, yet natural gas markets have failed to modernize at the same pace as electricity markets. Several issues with coordination between electricity and gas scheduling fundamentally limit the flexibility of natural gas units.

One issue in coordinating natural gas and electricity markets is a discrepancy between when day-ahead electricity commitments are posted and when purchases for gas must be submitted. To allow generators a high degree of flexibility, requests for natural gas purchases should only be required *after* offers are made in the day-ahead electricity markets and commitments are made public. This is intuitively straightforward; generators should not have to guess how much gas they will need but rather should base this purchase on the expected amount of electricity they will need to generate.

However, natural gas markets have typically required purchasers to submit day-ahead requests *before* electricity markets post day-ahead commitments, forcing units to purchase gas based on an expectation of how they will be committed in the day-ahead electricity market rather than how they are actually committed. Because the adjustment periods (evening-day-ahead and intraday) for the natural gas markets are relatively illiquid, the sequencing of these markets can create significant challenges for natural gas plant operators who find they may have purchased an inappropriate amount of gas given the subsequent electricity market commitments.

While some progress has been made in better aligning electricity and gas markets, significant room remains for improvement. FERC Order 809 shifted the day-ahead submission time for the natural gas market from 11:30 AM Central Clock Time (CCT) to 1:00 PM CCT. For some markets, this change now gives generators a 30 minute window between the posting of day-ahead electricity commitments and the deadline for submitting purchase orders for natural gas. However, two markets, CAISO and SPP, continue to post electricity market commitments after the natural gas purchase order deadline. Further, while a 30-minute window is an improvement over no window at all, 30 minutes may be insufficient for generators to accurately compute gas requirements and submit bids. Only NYISO has a day-ahead commitment post time that provides adequate time for generators to schedule gas purchases.

A second problem arises from the limited flexibility of natural gas purchases in real time. All electricity markets operate real-time markets that dispatch and settle on five-minute intervals. In the natural gas market, FERC Order 809 mandates three intraday trading periods to adjust gas purchases and sales. While this represents an increase over the prior rules requiring only two intraday trading periods for natural

[16] PJM, "Energy Price Formation and Valuing Flexibility" (PJM, June 15, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

[17] US DoE, "Staff Report to the Secretary on Electricity Markets and Reliability" (Washington, D.C.: U.S. Department of Energy, August 2017), https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

[18] Ibid., 126.

Table 2
Day-ahead market commitment post times.

Electricity Market	Time for Publication of Day-Ahead Commitment Bids (CCT)	Before/After Natural Gas Timely Nomination Deadline
CAISO	3:00 PM	After
ISO-NE	12:30 PM	Before, but with only a 30 minute window
PJM	12:30 PM	Before, but with only a 30 minute window
MISO	12:30 PM	Before, but with only a 30 minute window
NYISO	10:00 AM	Before, with a 3 hour window
SPP	2:00 PM	After
ERCOT	12:30 PM	Before, but with only a 30 minute window

gas, a good deal of additional flexibility is still unavailable due to a very limited number of intraday gas trading periods. For example, multiple public interest organizations have suggested that intraday markets should have up to 12 periods for adjusting natural gas purchases.[19] Table 2 summarizes post times in various RTOs.

Another recurring problem at the gas-power interface is the issuance of operational flow orders (OFOs), which restrict the amount of available gas supply or force plants to use gas beyond their purchased amount. OFOs are issued by gas companies when they need to increase or reduce offtake to maintain the integrity of the gas transportation and storage system. For example, during the Polar Vortex, demand for electricity and natural gas (predominantly for home heating) increased significanty in the Northeast U.S. However, due to this high amount of sustained demand, as well as operational problems (natural gas well freeze-offs) many gas companies issued OFOs, restricting the amount of gas available to generators.[20] In PJM, for example, during the Polar Vortex up to 70% of operating reserves were unavailable during certain periods because of natural gas supply constraints.[21] Gas companies may issue OFOs for many reasons, which can significnantly hamper generators' ability to respond flexibly to market conditions.[22] These problems are exacerbated by the poor alignment of gas and wholesale electricity markets.

3.4. Minimize restrictions on resource participation

To operate the grid reliably and at least cost, RTOs should rely on all resources that can provide necessary services. RTOs should be technology neutral: If a technology is able to provide services, it must be allowed to do so. This can pose challenges for RTOs when the algorithms and dispatch software they have written to dispatch a set of resources does not apply well to certain new resources.[23] However, this does not mean new types of resources should be precluded from offering services where they can, and RTOs must evolve to incorporate new technologies as they become available.

Yet the imposition, either directly or indirectly, of technological limitations on resource types, which preclude them from offering certain services, is a major barrier to utilizing the flexibility of existing resources in some RTOs. These restrictions come in (at least) two forms: restrictions based on the *type* of resource or restrictions based on the *size* of the resource.

For example, in PJM, distributed resources, including behind-the-meter battery storage, can only connect as a generation resource or register as demand response (DR). Registering as a generation resource is prohibitively expensive and time consuming for most distributed resources. As a registered DR resource in PJM, resources are banned from ever injecting power beyond the meter, meaning that participation of these resources is limited to reducing on-site load to zero, rather than being able to inject power back into the system.[24] Similarly, DR resources are limited to participating in a subset of PJM's markets, and therefore this designation further limits the ability of distributed storage to offer services to PJM.[25] As more distributed energy resources come online, RTOs need to consider how they can better incorporate these technologies and unlock their potential. Some RTOs have already taken steps in this direction.

3.4.1. Example: NYISO behind-the-meter net generation resource

NYISO's Behind-the-Meter Net Generation (BTM:NG) resource is a good example of a proactive change to product definitions that will allow more distributed energy resources to participate in the wholesale market.

Prior to the BTM:NG resource, NYISO prohibited behind-the-meter generators from participating in the wholesale markets. The BTM:NG resource now allows behind-the-meter storage resources connected to the transmission or distribution system to participate in NYISO's markets by establishing a resource category and introducing new definitions that enable participation by these resources.

NYISO requires BTM:NG resources to submit both their installed capacity as well as their estimated host load when submitting bids into the capacity, energy, and ancillary services markets, which allows NYISO to estimate the net generation available to dispatch. NYISO also allows multiple individual generators serving a single host load to aggregate into a single BTM:NG resource. Though the BTM:NG product is quite new, it could provide a template for other RTOs seeking to incorporate distributed energy resources into wholesale markets.

NYISO still must resolve issues with how BTM:NG resources are classified. For example, only resources at least 2 MW in size with at least 1 MW of capacity available for dispatch are eligible to participate in the wholesale market.[26] However, NYISO has indicated that it plans to revise and refine this product over time, including lowering the size threshold. All in all, the BTM:NG resource is a good first step towards including DERs into wholesale markets.

[19] "Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities: Comments of the Environmental Defense Fund, Conservation Law Foundation, the Sustainable FERC Project and the Clean Energy Group," November 28, 2014, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13697271.

[20] "Winter 2013-2014 Operations and Market Performance in RTOs and ISOs" (Washington, D.C.: Federal Energy Regulatory Commission, April 1, 2014), https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf.

[21] FERC, Order 809: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, No. RM14-2-000 (April 16, 2015).

[22] "Comments of CalPeak Power, LLC and Malaga Power, LLC Regarding Implementation of Order 809," May 7, 2015, https://www.caiso.com/Documents/CalPeak_MalagaComments_FERCOrderNo809.pdf.

[23] "Re: Midcontinent Independent System Operator, Inc.'s Sections 205 and 206 Filings to Amend Tariff Provisions to Establish a Stored Energy Resource - Type II Docket No. ER17-__-000; EL17-8-000" (MISO, April 3, 2017).

[24] Of course, injecting power at the distribution scale can be challenging for the system to handle, but this tends not to be an issue until the amount of injected power approaches the total amount of demand on the feeder. See: A.F. Mensah (PJM, April 18, 2016), http://www.pjm.com/~/media/committees-groups/committees/mrc/20160418-special/20160418-item-02b-problem-statement-af-mensah-presentation.ashx; "Electric Storage Participation in Regions with Organized Wholesale Electric Markets: Comments of Public Interest Organizations, Docket No. AD16-20-000," June 6, 2016.

[25] "Comments of Advanced Energy Economy," Electric Storage Participation in Regions with Organized Wholesale Electric Markets (Federal Energy Regulatory Commission, June 6, 2016), 16.

[26] NYISO, "Behind-the-Meter Net Generation Fact Sheet," n.d., http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/CRIS_Transition/BTMNG%20Fact%20Sheet.pdf.

4. Conclusions

Simple changes to market rules could unlock a significant amount of flexibility for RTOs. In some instances, existing market rules, even when well intentioned, preclude certain resources from offering services even though they could provide value. In other instances, market rules designed to accommodate certain technologies or contract structures limit the ability of grid operators to tap those resources.

To address schedule and commitment issues, RTOs can take several steps.

First, self-scheduling should be minimized or eliminated, and all resources should participate in economic dispatch. RTOs either can require units to submit offer curves or can lower the offer floor to induce units to participate in economic dispatch.

Second, RTOs can also follow MISO's example to include variable generation in economic dispatch, subjecting it to all the same conditions and giving it access to all the same benefits that other market participants enjoy (e.g., uplift and make-whole payments).

Third, to the maximum extent feasible, RTOs should also increase the share of imports participating in economic dispatch.

Allowing the energy market to send the right dispatch and investment signals is also of high importance. In particular, as more low or zero marginal cost resources come online, RTOs must maintain the ability for resources to offer negative pricing, which provides an important input for grid operators and creates investment signals for new flexible resources.

Ensure electricity market day-ahead commitments are posted at least an hour before the deadline for natural gas day-ahead purchase orders to allow generators sufficient time to accurately forecast and purchase gas.

Another key to unlocking flexibility is ensuring the gas fleet can operate as flexibly as possible. To this end, better electric-gas coordination and scheduling is needed. RTOs can work to increase the number of intraday trading periods for the purchase and sale of natural gas, and ensure natural gas market intervals clear ahead of electricity market intervals. Similarly, they can work with the natural gas industry and FERC to minimize operational flow orders by improving gas-electricity market coordination.

Finally, RTOs must ensure that all resources capable of providing services are able to do so by minimizing restrictions on resource participation. This is especially true for distributed resources, which grid operators can integrate by creating net generation products for distributed resources, enabling aggregators to participate via fleets, and making the size threshold as small as possible. Similarly, RTOs should ensure that market rules accommodate varying resource characteristics.

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