Market Power Mitigation Mechanisms for Wholesale Electricity Markets: Status Quo and Challenges

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Abstract

Market power has been a persistent challenge in designing wholesale electricity markets. Differences in the number or configuration of pricing zones does not impact the ability of a supplier to exercise unilateral market, but only what market outcomes are impacted by this exercise of market power. For this reason, tools able to detect market power conditions are crucial for ensuring the well functioning of all wholesale electricity markets, regardless of number of pricing zones. We first describe the trade-offs that must be balanced in designing a market power mitigation mechanism for any short-term wholesale electricity market. This is followed by a survey of the market power mitigation mechanisms that currently exist in the California Independent System Operator (ISO), the PJM Interconnection, the New York ISO, Mid-Continent ISO, and Electricity Reliability Council of Texas (ERCOT). Finally, we draw lessons from the US experience and try to address potential issues in the adoption of a market power mitigation mechanism in a low carbon electricity market.

Keywords: Market Power Mitigation, Electricity Market Design, Intermittent Renewables, Locational Markets, Pivotal Supplier Test, Conduct and Impact Tests, US Wholesale Electricity Markets

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1 Introduction

More than twenty years of experience with offer-based short-term wholesale electricity markets around the world have demonstrated a number of empirical regularities. First, conditions in the transmission network can arise when virtually any generation unit has a substantial ability to exercise unilateral market power. Second, it can be extremely difficult to predict when these conditions will arise very far in advance of when they actual occur. Third, the higher prices that result from the exercise of unilateral market when these conditions arise typically result in wealth transfers from electricity consumers to electricity producers, with little market efficiency benefit.

This has led all United States (US) short-term wholesale markets to adopt an automatic market power mitigation mechanism. These mechanisms are built into the market-clearing software and automatically mitigate the offers of any supplier that is determined to possess a substantial ability to exercise unilateral market power before clearing the short-term market. The details of these mechanisms differ across the markets, but all are aimed at limiting the wealth transfers from electricity consumers to producers due to the exercise of unilateral market power when these system conditions arise.

Automatic market power mitigation mechanisms are primarily a North American market phenomenon. Offer-based short-term markets in other parts of the world usually designate on an annual basis certain generation units as *must-run* because they are necessary for reliable grid operation according to dedicated assessments carried out by the system operator. These units are usually guaranteed full cost recovery for their *must-run* status. An alternate interpretation of this *must-run* status is that these units possess a substantial ability to exercise unilateral market power because they must be accepted to supply energy or operating reserves regardless of their offer price.

A number of US short-term markets began operation with this *must-run* generation unit approach to market power mitigation. The initial California zonal market that began operation in April of 1998 had a number of units designated as Reliability Must-Run (RMR) because of their significant ability to exercise unilateral market.[1] Despite their best efforts, US market operators following this approach to market power mitigation were unable to reduce significantly the number of *must-run* units and as a consequence implemented the automatic local market power mitigation approach during the transition to implementing a locational marginal pricing (LMP) market design.[2]

A larger share of intermittent renewables can increase the need for an automatic market power mitigation mechanism because the patterns of transmission congestion become less predictable on the annual basis used to determine the *must-run* status of generation units. Additional operating constraints on all dispatchable generation units must also be introduced into the market-clearing mechanism as a result of this intermittency. Both outcomes can increase the frequency that dispatchable generation units have a substantial ability to exercise unilateral market power.[3] Both of these factors can also increase the ability of generation unit owners to predict on day-ahead basis when they have a substantial ability to exercise unilateral market power.[4]

Consequently, an automatic market power mitigation/monitoring mechanism could be a useful tool for any wholesale electricity market with a significant amount intermittent renewables because competition among generation unit owners takes place through the actual transmission network subject to the actual operating constraints on generation units and the transmission network. The configuration of the short-term market is largely irrelevant to amount of unilateral market power a supplier is able to exercise under given set of operating conditions. A single price market, multiple zone market, or nodal pricing market does not generally change the ability of a supplier to exercise local market power because suppliers

[1]Bushnell and Wolak (1999) present empirical evidence that suppliers with RMR units in their portfolio used them to leverage the market power these units possessed to raise the prices paid to other generation units in their portfolio.

[2]Graf et al. (2020a) provide a detailed description of an LMP market design that not only accounts for nodal resolution of the transmission network but also co-optimizes energy and ancillary services.

[3]See for example Graf et al. (2021) on re-dispatch cost increase as a result of a persistent negative net demand (demand net of intermittent renewables) shock.

[4]Graf et al. (2020b) present empirical evidence demonstrating that suppliers can predict with significant confidence when these system conditions arise.

know that the actual operating constraints on the transmission network and generation units must be respected in actual system operation.

Put succinctly, all market participants know that in real-time all physical operating constraints must be respected regardless of the form of the financial market used to set prices and initial generation schedules. However, different financial market designs influence the strategies that suppliers use to exercise unilateral market, which means that the market power mitigation mechanism must be tailored to the specific short-term market design. To assist in this process, we identify the important trade-offs must be balanced in designing a market power mitigation mechanism for any short-term market design.

We identify an important trade-off between the design of the short-term market and how the exercise of unilateral power market impacts short-term market outcomes. A zonal day-ahead market design that does not account for all transmission network constraints and generation unit operating constraints, will require a significant re-dispatch process. Without a market power mitigation mechanism, the cost of the exercise of unilateral market will show up primary in this re-dispatch process. In a LMP market design where all transmission constraints and many generation unit operating constraints are modeled, the exercise of unilateral market would likely show up in prices in this market as well as the real-time market.

With a market power mitigation mechanism in place under a LMP market design, if no network or operating constraints change between the day-ahead market and real-time, then real-time output levels will equal day-ahead scheduled output levels. In contrast, under a zonal day-ahead market it is highly unlikely that re-dispatch actions will not be needed to obtain feasible real-time operating levels. This fact makes it more challenging to design an effective market power mitigation mechanism for zonal-pricing market versus nodal-pricing market.

To understand better the trade-offs in this process, we survey the market power mitigation mechanisms that currently exist in US wholesale markets, focusing both on the common features as well as important differences between these mechanisms and the reasons for these differences. We then draw lessons from this survey for the design of market power mitigation mechanism for a low carbon electricity market.

The remainder of the paper proceeds as follows. Section 2 explains why all wholesale electricity market regardless of number of pricing zones, requires a market power mitigation mechanism. Section 3 describes the trade-offs that must be balanced in designing a market power mitigation mechanism for any short-term wholesale electricity market. Section 4 surveys the market power mitigation mechanisms that current exist in the California Independent System Operator (ISO), the PJM Interconnection, the New York ISO, Mid-Continent ISO, and Electricity Reliability Council of Texas (ERCOT). Section 5 presents lessons from the US experience for the design of a market power mitigation mechanism for a low carbon electricity market. Section 6 concludes.

2 Market Power Mitigation in Wholesale Electricity Markets

Most wholesale electricity markets employ multiple forward financial markets before real-time system operation. Early wholesale markets in the United States and existing European wholesale markets employ a day-ahead zonal market design that ignores many transmission network constraints within these pricing zones and operating constraints on generation units in setting day-ahead generation schedules. These markets also allow further financial trading incremental and decremental energy in intra-day markets before the real-time market operates. Under these zonal market designs, the system operator must utilize re-dispatch actions by generation unit owners to obtain generation unit operating levels throughout the day that are physically feasible and respect all transmission network and other relevant operating constraints.

The re-dispatch process either increases the output level of some generation units and reduces the output level of other generation units relative to schedules that emerge from the zonal market mechanism. Generation units that increase their output must typically typically be paid a price above the market-clearing price from the zonal market. Generation units that reduce their output must typically sell this output back at a price below the market-clearing price from the zonal market.

A generation unit owner that recognizes one of their units must operate or cannot operate because of an constraint not modeled in the zonal market has a significant ability to exercise local market power. Without some form of market power mitigation, there is no limit on the price a supplier can offer and still be certain that their unit will be accepted to supply energy. Similarly, there is no lower bound on the price at which supplier can bid to buy back energy scheduled in the zonal market that the unit owner knows is unable to be produced in real-time. The configuration or number of zones in zonal market does not impact the ability of supplier that must operate or cannot operate because of a system reliability constraint to exercise unilateral power.

If the supplier faces little or no competition for this local need, then its offer price must be accepted or system reliability will be threatened. By the same logic, if energy sold in the zonal market cannot be delivered in real-time and reducing output from this unit is only way to obtain a feasible real-time operating level, this unit's bid price must be accepted or system reliability will be threatened.

This same logic applies to a locational marginal pricing (LMP) market. If a generation unit must operate in real-time because of an operating constraint, then the unit's offer price must be accepted or system reliability will be threatened. However, different from a zonal market design, a generation unit offer will not be accepted in the day-ahead LMP market if this violates any operating constraint modeled in the day-ahead market-clearing mechanism.

These examples illustrate several important points about limiting the exercise of unilateral market power in any wholesale electricity market. Regardless of the number or configuration zones, competition to supply energy takes place through the actual transmission network subject to actual operating constraints on generation units. If a supplier faces little competition to meet a local energy or operating reserves need for a given set of real-time system conditions, then there is little limit to the offer price it can submit, regardless of the configuration zones or number of pricing locations in the wholesale market design.

Without some form of market power mitigation mechanism wealth transfers from consumers to the generation unit owner will occur when these system conditions arise. Most wholesale markets have an offer cap and offer floor that limit the offer prices that suppliers can submit. These restrictions on offer prices provide limited protection against the exercise of unilateral market power. Some zonal markets also run cost-based re-dispatch processes where incremental energy is sold at the unit's variable cost and decremental energy is purchased at the day-ahead price or the unit's variable cost. This limits the exercise of unilateral market power by generation unit owners, but it does not eliminate it.

The extent to which a day-ahead market accounts for expected real-time system operating constraints can affect how the exercise of unilateral market power will materialize. A day-ahead market that reflects all the relevant operating constraints allows a more coordinated planning of the resources needed in real-time. In case of perfectly forecasting real-time system conditions, final schedules of generation units will follow their planned day-ahead schedules. However, without a market power mitigation mechanism, the exercise of unilateral market power in the day-ahead market could alter the price paid for all consumption in a given region of the grid. A market design that neglects some transmission and other system constraints in the day-ahead market and solves (prices) them only at a later stage (re-dispatch market) could amplify the exercise unilateral market power in re-dispatch market because fewer resources are available in real-time due to technical limitations of generation units (e.g., start-up time, ramp rates) and limited effective competition that could also be induced through the unilateral day-ahead market scheduling decisions.[5] However, these increased re-

[5]If re-dispatch quantities are low to moderate there is typically sufficient (local) dispatchable capacity online and competitive forces may be strong enough to get acceptable outcomes. However, if large quantities need to be changed we are in a different terrain because potentially additional power plants need to be committed (started up) which can affect the mode of competition drastically because of the arising fixed

dispatch costs are likely to be applied to a smaller amount of energy because only deviations from the day-ahead market schedules are priced.

3 Trade-Offs in the Design of Market Power Mitigation Mechanisms

A market power mitigation mechanism attempts to improve market performance relative to a cost-based re-dispatch process for a zonal market or cost-based real-time dispatch in LMP market. The downside of a cost-based re-dispatch or cost-based real-time market is that the market operator does not know the true cost of producing energy from any generation unit, only the *regulator verified* variable cost of producing energy. Moreover, the generation unit owner has strong incentive to take actions to increase this *regulator verified* variable cost, in order to increase the profits it earns from the re-dispatch market or the real-time LMP market.

A bid-based re-dispatch process has the advantage when the generation unit owner faces significant competition from other generation unit owners for incremental energy or decremental energy in the re-dispatch process the unit owner has a strong financial incentive to submit a competitive price offer in the re-dispatch process. This logic implies that the major challenge in the design of an effective market power mitigation mechanism is determining the circumstances when a generation owner faces effective competition for incremental or decremental energy or operating reserves.

costs. The latter case is less relevant in LMP markets because the commitment process is integrated into the day-ahead market design and the risk of having too few units on-line in some locations and too many units in some other locations is significantly reduced which (i) reduces the demand for re-dispatch and (ii) ensures that local resources have the capacity to handle small schedule deviations. Note that small quantities for re-dispatch will always occur under any market design simply because day-ahead planning is based on *forecast* real-time realizations of demand and output from renewables. However, because the zonal day-ahead market-clearing imposes only a few restrictions on market participant's schedules of how to operate their resources, this means also that complex offer strategies to intentionally congest the network or violate other system constraints with the objective to participate in the generally more lucrative re-dispatch market are permitted (see, e.g., Graf et al., 2020b, on these strategies). Therefore, re-dispatch quantities can be *endogendously* driven by market participant's offer strategies.

When the generation unit owner is deemed not face effective competition, offer mitigation should take place. Otherwise, the offers submitted by the generation unit owner should be used in the re-dispatch process because competition from other suppliers should be sufficient to ensure a lower incremental energy offer and higher decremental energy bid than a *regulator verified* variable cost.

4 Survey of US Market Power Mitigation Mechanisms

The main focus of market power mitigation mechanisms in the US is on suppliers in the day-ahead and the real-time LMP markets. This section first gives an overview of the basic features of US market power mitigation mechanisms. This followed by a description of the details of the market power mitigation that currently exist in the California Independent System Operator (ISO), the PJM Interconnection, the New York ISO, Mid-Continent ISO, and Electricity Reliability Council of Texas (ERCOT).

4.1 Overview of Market Power Mitigation in the US

Two fundamentally different approaches to market power mitigation are utilized in US nodal markets. Under the "structural approach" the decision to rely on generation offers as opposed to mitigated offers is based a set of pre-determined system conditions and not on the offers of any market participant. This approach typically checks for the existence of (jointly) pivotal players for relieving congestion along certain transmission paths and determines whether a constraint is structurally competitive or non-competitive based on whether a pre-specified number of suppliers are jointly necessary to relieve this constraint. If a set of suppliers are determined have a sufficiently large ability to exercise unilateral market power, their offer prices will be replaced with an regulator-determined offer price. This reference level offer price is the regulator's estimate of what the supplier would submit if it faced effective competition. The main wholesale markets that follow this approach to market power mitigation are the California ISO and PJM Interconnection.

The "conduct and impact" approach employs a two-step process that assesses the impact of a player's conduct on the market-clearing price. The first step tests whether the resource's offer price exceeds a specific threshold, typically called the generation unit's reference level. This is the conduct test. If this test fails, the impact test is applied. This test determines if the resource's offer price has an impact on the market-clearing price of energy relative to market-clearing price that would result if from replacing the unit's offer with its reference level. If an offer price fails both the conduct and the impact test, this offer price will be replaced by the unit's reference level in clearing the market. The Conduct and Impact approach is used in ISO-NE[6] (New England ISO), MISO[7] (Midwest ISO) and NYISO (New York ISO). This approach also typically uses transmission constraints to identify areas that are more likely to be subject to the exercise of substantial unilateral market power. In order to do this, the above-mentioned wholesale market operators define two different market areas, "constrained" and "unconstrained" areas. Offers in constrained areas are generally subject to more stringent conduct and impact thresholds. Table 1 summarizes the advantages and disadvantages of the Structural (RSI) and the Conduct and Impact market screening tests.

Reference levels are important determinants of the effectiveness of a market power mitigation mechanism. The reference level for a generation unit is the answer to the question: What is a correct proxy for a competitive offer prices? In other words, what offer price would the supplier have set if it faced effective competition? It is generally agreed that a supplier with no ability to exercise unilateral market power units would offer to sell energy at its short run marginal cost of production.[8] Having this said, the first natural answer on how to estimate competitive offers would be to start from units' variable costs. But this approach must be adapted to technologies that do not have an explicit variable cost, but

[6]Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

[7]15 US-states in the midwest and the Canadian province of Manitoba.

[8]Under competitive conditions, offers can be expected to reflect marginal costs and so the clearing price is the highest marginal cost amongst the dispatched generators that are not operating at minimum or maximum. This is also referred to as the marginal cost of the marginal generator.

instead only have an opportunity cost of producing energy such as a hydroelectric unit with a finite reservoir. There are four main ways to set reference levels.

- Cost-Based Reference Level: is based on unit's incremental costs plus some adders (generally a percentage of incremental costs) for frequently mitigated market participants. The incremental costs generally consist of fuel cost, the variable part of operation and maintenance (O&M) cost, emissions cost, and grid management expense. There are two main approaches in defining cost-based reference levels. In the first approach, adopted in ISO-NE, MISO and NY-ISO, the resource-specific reference level is determined based on a process conducted by the ISO ahead of time with the participant. The reference level is an equation with inputs that can change day to day, but this is established prior to the market session through a consultation process between the market participant and the ISO. In the second approach, used by PJM, participants submit their resource-specific cost-based reference level every day together with regular energy offers. A market manual dictates how this reference level should be determined and submitted cost-based offers must be determined in a manner consistent with this market manual. The advantage of the cost-based method is that market participants that are frequently mitigated can, at least, recover their costs. On the other hand, participants can have the incentive to submit or negotiate biased reference levels to sidestep the effects of mitigation mechanisms.

- Accepted Offer-Based Reference Level: is calculated based on features of the distribution of accepted offer prices from that generation unit during competitive competitive over the past (usually 90) days. The main advantage of this method is that it is based on market-based information instead of information submitted by units. This makes it well-suited for hydroelectric and other generation resources with opportunity costs of producing electricity. The disadvantage of this approach is that for frequently mitigated units the sample of accepted offers in competitive periods could be very small and therefore biased by outliers. Offer-based reference levels are particularly applicable for generation resources that are dispatchable (i.e., whose output level is determined by the LMP market), where competitive conditions prevail in most hours, providing a strong incentive for suppliers to offer competitively (at or close to their marginal costs).

- Market Price-Based Reference Level (LMP-based): is calculated based the distribution of fuel-adjusted market-clearing prices during competitive conditions over the past (usually 90) days. This method has the same advantage of the offer-based method being market driven instead of submitted-cost driven but it does not always guarantee that market participants are fully recovering their short run marginal costs.

- Counter-factual-Based: An alternative approach to establish reference levels could be to define counter-factual competitive geographical markets. For example, the market for regional/zonal upward reserve may not be competitive but the national market for reserves may is. Hence, clearing the re-dispatch market model, ignoring the zonal reserve requirements may deliver reference (marginal) prices may that are an acceptable alternative to the cost estimates. The advantage of this approach is that the reference prices are market-based. However, the disadvantage is that the definition of what is a competitive counter-factual market is exogenous and may also change by the season of the year or hour of the day. It may also change over time when for example market participants merge or additional capacity is added or more renewable capacity will be installed.

In most US wholesale markets an adder is paid on top of the cost-based reference level (normally 10%). A likely reason for this could be that it is not easy to estimate the unit's marginal cost and by awarding a 10% the regulator avoids disputes with the generation unit owner about their reference level. Furthermore, production costs change over the course of time and updating them frequently could increases administrative costs for the market operator. So instead of making this decision for each unit every day, the market operator and regulator simply prefer to award an adder to cover the fact that the reference levels are not updated on a daily basis. Nevertheless, it is important to emphasize that market participants have an incentive to negotiate higher reference levels than their true marginal costs.

For all of these market power mitigation mechanisms the market price be determined replacing the offer price of mitigated units with the unit's reference level. Table 2 summarizes the main features of the surveyed market power mitigation systems. A discussion of specific market power mitigation mechanisms will be discussed in the following subsections.

4.2 California ISO (CAISO)

The California Independent System Operator (CAISO) has had a local market power mitigation system (LMPM) in place since 2008. The present LMPM system is the result of many revisions that have taken place over the past decade. The CAISO employs a structural approach to market power mitigation because it uses a (three) pivotal player test to assess whether a constraint is structurally competitive or non-competitive. This decision is the responsibility of the internal Department of Market Monitoring (DMM).

The Market Surveillance Committee is an independent body of skilled industry experts that provides comments, critiques and recommendations about the ISO market monitoring process (as described in the tariff) and a variety of market issues to the ISO Chief Executive Officer and Board of Governors. The Committee is required under the ISO "Tariff" document to review and comment on DMM analyses and reports. To ensure independence, none of its members are affiliated with or have any financial interest in any market participant. Their charter allows them to suggest changes in rules and protocols or recommend sanctions or penalties directly to the ISO Governing Board.

DMM publishes annual reports[9] which contains an extensive review of the main issues and of market performance of the previous year. In this report, competitiveness of overall market

[9] For 2018 see: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

performance is assessed based on the *price-cost markup*, which represents a comparison of actual market prices to an estimate of prices that would result in a competitive market in which all suppliers behave as price-takers. This competitive baseline is used to assess the to which degree market prices exceed competitive benchmark levels. DMM calculates this competitive benchmark price by recalculating day-ahead market prices after replacing the market price offers of all gas-fired units with offers equal to each unit's actual marginal costs.

4.2.1 Three Pivotal Supplier Test

The dynamic competitive path assessment (DCPA) methodology proposed in 2011 and discussed in Bushnell et al. (2011) is the main building block of CAISO's LMPM. The DCPA builds on its predecessor, the competitive path assessment, whose goal was to identify transmission constraints that segment the market into locational markets where firms have market power in a constrained area (see Rahimi et al., 2007, for more details). The DCPA is part of the current LMPM system[10] and its objective is to identify binding transmission constraints accounting also for the actual operational (dynamic) constraints of conventional power plants. In a first step, a so-called "all-constraints run" is performed to identify transmission constraints that will be binding in the market run. This run comprises a full unit commitment and dispatch enforcing all transmission constraints and ancillary service requirements. The run is based on unmitigated offers. The "all-constraints run" is applied to the day-ahead market, the hour ahead scheduling process (HASP), as well as the real-time pre-dispatch (RTPD) market. In the HASP and RTPD CAISO load forecasts are used for the relevant period. Again a full unit commitment model (of units capable of coming on-line within the relevant time frame) and dispatch model is run with all transmission constraints and ancillary service requirements enforced.

In the next step, the binding transmission constraints must be differentiated between

[10] See Attachment B, "Competitive Path Assessment" of CAISO's current Business Practice Manual (BPM) for Market Operations, Version 64, January 29, 2020, and the latest version of the Tariff, Section 39 (`http://www.caiso.com/Documents/Section39-MarketPowerMitigationProcedures-asof-Sep28-2019.pdf`).

competitively binding and non-competitively binding. Remember a binding transmission constraint per se is not yet an indication for anti-competitive behavior of any of the market participants. The criterion for designating a transmission constraint as non-competitive is when the fringe supply of counter-flow to the transmission constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the transmission constraint. Counter-flow to the transmission constraint means a flow in the opposite direction to the one which is congesting the binding constraint. The amount of counter-flow created by each resource can be calculated as the nodal shift factor (power transfer distribution factor[11]) times the resource's scheduled injection.

More formally, assume there is a constrained path j. Units in the set K are able to produce counter-flow, i.e., have the ability to make the transmission constraint less binding. Assume further that the units in the subset P of K include generators belonging to the top three suppliers that are potentially pivotal. Then the set $F = K \setminus P$ is the set of generators in K but not in P, or, less formally, the fringe counter-flow providers. The residual supply index for this test is then given by

$$RSI_{i,j} = \frac{\overline{\mathrm{CF}}_j(F)}{\mathrm{CF}_j(K)},$$

where $\mathrm{CF}_j(K)$ is the total counter-flow on the constraint with the initial generator output and $\overline{\mathrm{CF}}_j(F)$ is the maximum counter-flow of the fringe generators. If $RSI < 1$[12], then the tested suppliers have failed the pivotal supplier test and are declared to be pivotal. This also means that the transmission constraint has been found to be "non-competitive." The choice among which three suppliers select for the residual supply index test differs depending on the market. In the day-ahead market, potentially pivotal suppliers mean the three portfolios

[11]Nodal PTDF or DFAX quantifies the change of flow on a given network element relative to a unitary increase in the injections at the given node and it is defined as: (After-shift Power Flow – Pre-shift power flow)/ Total amount of power shifted

[12]In other words when the maximum available supply of counter-flow to the transmission constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the constraint.

of net sellers that control the largest quantity of counter-flow supply to the transmission constraint[13] and in the real-time markets (HASP/RTDP), potentially pivotal suppliers mean the three portfolios of net sellers that control the largest quantity of counter-flow supply to the transmission constraint that can be withheld from the real-time market. Counter-flow supply to the transmission constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's energy bid (not taking into account the ramp rate of the resource), measured from the dispatch operating point for the resource in the immediately preceding fifteen (15) minute RTDP interval or the preceding five (5) minute RTD interval, as applicable (taking into account the ramp rate of the resource), adjusted for self-provided ancillary services and de-rates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and de-rates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a transmission constraint as non-competitive for the RTM, counter-flow supply to the transmission constraint that can be withheld also reflects the minimum stable level of each short start unit with a start-up time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the RTDP. In determining whether to designate a transmission constraint as non-competitive for the RTDP, counter-flow supply to the transmission constraint that can be withheld also reflects the PMin of each short start unit with a start-up time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.[14]

Supply of counter-flow from all portfolios of potentially pivotal suppliers to the transmission constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the transmission constraint. The minimum available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given

[13]See Tariff 39.7.2.2 (a), ii.
[14]See Tariff 39.7.2.2 (b), iii.

its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.[15]

In a penultimate step, the locational marginal price (LMP) is decomposed into several components: It consists of a single market optimization run in which all modeled transmission constraints are enforced. Then, each LMP in the market will be decomposed into four components: (1) the energy component; (2) the loss component; (3) the competitive congestion component; and (4) the non-competitive congestion (NC) component. Under the LMP decomposition method, a positive non-competitive congestion component indicates the potential of local market power. The non-competitive congestion component of each LMP will be calculated as the sum over all non-competitive constraints of the product of the constraint shadow price and the corresponding shift factor (power transfer distribution factor).

For the non-competitive congestion component to be an accurate indicator of local market power, the reference bus that these shift factors relate to should be at a location that is least susceptible to the exercise of local market power. The CAISO selects as the reference bus the Midway 500kV bus when flow on Path 26[16] is north to south and the Vincent 500kV bus when flow on Path 26 is south to north. The Midway and Vincent 500kV buses are excellent choices for LMPM purpose because they are located on the backbone of the CAISO's transmission system near the center of the California transmission grid with sufficient generation and roughly half the system load on each side. Therefore, these buses are very competitive locations, and are least likely to be impacted by the exercise of local market power. Every resource with an LMP non-competitive congestion component greater than the mitigation threshold price (currently set at zero) is subject to mitigation.

The final step will be to apply the offer of any generator having an overall positive congestion component on non-competitive constraints. Mitigated generator offer prices will be at the higher of the Default Energy Bid (DEB) or the competitive LMP as described in

[15]See Tariff 39.7.2.2 (b), ii.
[16]Path 26 is a set of three Southern California Edison (SCE) 500 kV power lines

the next section.

4.2.2 Reference Levels

Bids from resources with a non-competitive component greater than zero will be mitigated downward to the higher of the resource's Default Energy Bid (DEB), or the "competitive LMP" (max DEB, competitive LMP) at the resource's location, which is the LMP established in the LMPM run minus the non-competitive congestion component thereof (Competitive $LMP_I = LMP_I - LMP_I^{NC}$). A small configurable adder, which in all cases will be less than 0.01 USD, shall be added to the Competitive LMP.[17]

A resource can obtain one of the three following options to calculate its Default Energy Bid:

1. Variable Cost Option: incremental cost (comprised of incremental fuel cost + a volumetric Grid Management Charge[18] adder + a greenhouse gas cost adder if applicable) + variable operation and maintenance cost: A 10% is added to the sum. For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve. A bid adder is included for resources that have been mitigated over 80% of the hours of the previous 12 months. Bid adders are negotiated with the CAISO or set to a default level of 24 USD/MWh.

2. Negotiated Rates Option: a resource submits a proposed default bid with supporting documentation that can be approved or rejected by the CAISO

3. LMP Option: The CAISO will calculate the LMP Option for the Default Energy Bid as a weighted average of the lowest quartile of LMPs at the Generating Unit's Node in periods when the unit was Dispatched during the preceding ninety (90) day period.

[17] See CAISO's current Business Practice Manual (BPM) for Market Operations, Version 64, January 29, 2020, Section 6.5.1.

[18] It is the mechanism that the ISO uses to recover its operating and capital costs from the entities that utilize the ISO's services.

Notice that the philosophy of this mitigation approach is to modify a market participant's offer prices only when those offers potentially reflect the exercise of market power. This is done by separating the transmission constraints into competitive and non-competitive constraints.[19] If market participant's offer prices were mitigated to their DEB and not floored to the level of the competitive LMP it may happen that the output of a mitigated generator will be higher than required to relief congestion on non-competitive constraints. Consequently, this would be a case of over-mitigation.

4.3 Pennsylvania-New Jersey-Maryland Interconnection (PJM)

The PJM Market Monitoring Unit (MMU) has been responsible since 1999 for promoting competition in PJM's electric power market by observing and commenting on actual and potential design flaws in market rules, standards and procedures, and identifying structural problems in PJM markets that may inhibit robust and competitive markets. In 2008, Monitoring Analytics[20] was established by spinning off the MMU in a separate and independent market monitoring company under a long-term contract. As a consequence, PJM became one of the most unique cases in the United States: market power mitigation and monitoring is entirely carried out by an external market monitor, without an active role of the ISO in this field (as in other more frequent cases across the country where both external and internal monitors are involved in the process). Under the PJM Market Monitoring Plan, the PJM Market Monitoring Unit (MMU named Monitoring Analytics) is responsible for monitoring compliance with the rules, standards, procedures, and practices of PJM markets. Every year Monitoring Analytics (MA) publishes an annual report[21] It also gives recommendations for the future implementation of the market power mitigation procedures highlighting issues encountered in the previous year's application. MA also uses measures of market structure to monitor the competitiveness of PJM's performance and detect system wide market power:

[19] A binding constraint is defined non-competitive when, taking out the pivotal players, the non-pivotal players can relieve the constraint.

[20] http://www.monitoringanalytics.com/home/index.shtml.

[21] MonitoringAnalytics (2020): PJM State of the Market - 2019

- Residual Supply index: used in the Regulation Market, the Capacity Market and the Energy Market to detect structural market power. The process is the same seen for local market power but in this case a wider number of suppliers is ranked (all those eligible for those markets and not only those relevant to a binding constraint).[22]

- Price-Cost Markup index: for marginal unitsis a measure of the extent of market power exercised. For units not on the margin, the markup index is less relevant.

- Net revenue index is an indicator of the profitability of generation investment and a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets.

- Market Share index: for example, the HHI (Herfindahl-Hirschman Index) that is a proxy of market concentration calculated by summing the squares of the market shares of all firms in a market.

PJM can be defined as an example of structural market power mitigation approach. The mitigation is based on the structure of the market (three largest suppliers available to relieve constraint) rather than on the direct impact of market players on the clearing price. Similar to CAISO, a three pivotal supplier test is applied both in the day-ahead-market and in the real time market to assess if an offer is uncompetitive and if three suppliers are jointly necessary to relieve a constraint. Distribution factors of constraints are examined to determine which resources are crucial for relieving constraints. Only resources with distribution factors greater than three percent are defined as capable of relieving constraint. As in other US markets, resources that fail the three pivotal player test are mitigated.

[22] System-wide pivotalness is tested.

4.3.1 Three Pivotal Supplier Test

To measure the degree to which the supply for pivotal players is required to meet demand of counter-flow necessary to relieve constraint the three pivotal supplier test[23]. Two variables are considered for the application of the test:

- Relevant Demand: the effective incremental MW needed to relieve the constraint.
- Relevant Supply[24]: incremental MW of supply available to relieve a binding constraint. To be considered relevant, the distribution factor (DFAX)[25] must have an absolute value equal to or greater than the DFAX used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint.[26] To be included in the relevant market for the three pivotal player test, only the incremental effective MW of supply that is available at a price lower or equal to 1.5 times the clearing price P_c that would result from the intersection of demand (counter-flow required, see below) and the incremental supply available to resolve the constraint.

The importance of defining a relevant market (supply) is to include in the test only the players that can impact (or potentially could impact) market price. The concept here is to define market power as the ability of a firm to raise prices above competitive levels and still continue to sell its output. To do this before running the test, the 1.5 threshold is set to exclude players that would never have the chance to raise the equilibrium price because their output would be replaced by other competitors. The following steps take place to define the three pivotal players. First, the incremental MW of supply to relieve a

[23]For further details see PJM Tariff Manual `https://www.pjm.com/directory/merged-tariffs/oatt.pdf` or `https://www.pjm.com/-/media/committees-groups/committees/mc/20180927/20180927-item-04-draft-tariff-attachment-dd-section-6-revisions.ashx` and Attachment M of the Tariff

[24]This test measures effective control of the capacity necessary for the relief of a constraint. Generation capacity controlled directly by the same company or holding (or indirectly through contracts) is considered as a single player.

[25]DFAX is the equivalent to the PTDF seen in CAISO.

[26]Usually between 3 to 5 percent.

constraint is defined as $MW \cdot DFAX$. Second, the system clearing price P_c is set as threshold $P_c = \frac{Offer_c - SystemMarginalPrice}{DFAX_c}$.

To be part of the relevant market, the effective incremental offer of supplier i has to be less than 1.5 times the clearing price that would result by the intersection of relevant supply and relevant demand for counter-flow: $P_{ie} = \frac{Offer_i - SystemMarginalPrice}{DFAX_i} \leq 1.5P_c$. The effective incremental supply of supplier i is then defined as a function of the clearing price $S_i = MW(P_ie)DFAX_i$. If S_i is the relevant supply for one supplier, the total relevant supply for all the n players in the relevant market can be defined as $S = \sum_{i=1}^{N} S_i$.

In the next step, each relevant effective incremental supplier from 1 to N is ranked from the largest to the smallest relevant supply relative to the tested constraint. In the first iteration of the test, the two largest relevant suppliers to the constraint are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply. The resulting net amount of relevant effective supply is divided by the total counter-flow required (D, relevant demand).

Finally, the residual supply index for three pivotal suppliers RSI_3 is defined by the following ratio

$$RSI_3 = \frac{\sum_{i=1}^{N} S_i - \sum_{i=1}^{2} S_i - S_j}{D},$$

where $j = 3$, the third largest supplier being tested together with the two largest suppliers. If RSI_3 is less or equal to 1 then the three players tested fail the test and are considered jointly pivotal in the relevant local market crated to relieve the tested constraint. If RSI_3 is greater than 1, then the three largest relevant suppliers pass the test and all the other smaller suppliers in the rank ($j = \{4, 5, 6, \ldots, N\}$) pass the test. If the three largest suppliers fail the test, more iterations are performed, with each subsequent iteration testing a subsequently smaller supplier ($j = \{4, \ldots, N\}$) in combination with the two largest suppliers. Each iteration verifies if RSI_3 is less or equal to 1, indicating that the tested supplier, in combination with the two largest suppliers, has failed the test. The iteration of the test continues until one combination of the two largest suppliers and a supplier j pass the RSI_3

test. The iteration stops when the result of this process is that RSI_3 is greater than 1 and the remaining suppliers in the rank are concluded not to be pivotal. Note that PJM's RSI test is, with different notation, conceptually very similar to the RSI test seen in the CAISO section. $\overline{\mathrm{CF}}_j(F)$ seen in CAISO is a generalization of $\sum_{i=1}^{N} S_i - \sum_{i=1}^{2} S_i - S_j$ where the first is a generalized to all the possible F Fringe players and the latter considers a case with three relevant players. Both RSI tests have the quantity of available supply for counter-flow netted of the n relevant players tested at the numerator. The denominator is slightly different. The PJM test having the Demand for counterflow vs the CAISO test having the total counter-flow on the constraint.

4.3.2 Reference Levels

If a supplier fails the test and is deemed to be pivotal for a constraint, all the units that are part of that supplier's relevant effective supply with respect to a constraint may have their mitigated to their "cost-based" bid, equal to 110 percent of incremental production costs or to costs plus relevant adders for frequently mitigated units. PJM defines incremental production costs as the sum of fuel, emissions, and other variable operations and maintenance costs. Resources calculate their own reference level costs, which are referred to as cost-based offers, pursuant to a fuel cost policy that must be approved by PJM. A resource can also include opportunity costs in the reference level if these are legitimate and verifiable. The external market monitor verifies the reference levels submitted by resources. A relevant adder is added to costs for resources that are frequently mitigated. It is to note that offer capping only occurs when the supplier's relevant supply is offered at greater than cost plus 10 percent and is actually dispatched to contribute to the relief of the constraint in question.[27]

[27]See PJM-Cost-Development-Committee (2020): Cost Development Guidelines, manual 15, `https://pjm.com/~/media/documents/manuals/m15.ashx`.

4.4 Electric Reliability Council of Texas (ERCOT)

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power on the Texas interconnection that supplies power to more than 25 million Texas customers—representing 90 percent of the state's electric load. Different from the previously reviewed ISOs, the Federal Energy Regulatory Commission (FERC) does not have plenary jurisdiction over ERCOT because electric energy generated in the ERCOT region is not transmitted in "interstate commerce," as defined by the Federal Power Act, except for certain interconnections ordered by FERC that do not give rise to broader FERC jurisdiction. Hence, ERCOT is only regulated by the state of Texas (Public Utility Commission of Texas). ERCOT transitioned from a zonal to a nodal day ahead market in 2010. This market is frequently cited as North America's most successful in both generation and retail (Adib et al., 2013).

Texas was the last state in the United States that brought its electric industry under regulation in 1975, being vertically integrated until the end of the 90s. The two main acts that define market power in the Texas interconnection are the Electric substantive rule 25.503 and 25.504. The first saying that ERCOT has to monitor and mitigate and prevent market power abuses by determining if activities from market entities constitute market power abuses or are unfair, misleading, or deceptive practices affecting customers. It also defines abuse of market power as withholding of production, whether economic withholding or physical withholding, by a market participant who has market power. Substantive rule 25.504 gives more detail on the definition of market power in the wholesale electricity market defining it as the ability to control prices or exclude competition in a relevant market and market power abuse as practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition (predatory pricing, withholding of production, precluding entry, and collusion). It also establishes an exemption stating that a single generation entity that controls less than 5% of the installed generation capacity in ERCOT (excluding uncontrollable renewables) is assumed not to have ERCOT-wide market power. In the ERCOT, any generation entity may submit to the commission a mitigation plan for ensuring compliance with rule 25.503. Adherence to a plan approved by the commission constitutes an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan.

The commission's market oversight division (also known as MOD Squad) was responsible for market monitoring duties from August 2000 to August 2006 when this responsibility was transferred to Potomac Economics[28] that publishes every year an annual report[29] providing an assessment of the competitive performance and operational efficiency of the market.

As for other ISOs, a system-wide price cap was defined in 2015 equal to 9,000$/MWh.[30]

4.4.1 Two-Step Test

ERCOT uses a unique two-step market mitigation mechanism, which is automized in its security constrained economic dispatch (SCED), to address issues related to the exercise of locational market power. This design can be defined as a hybrid. Having somehow the flavor of the structural approach but also setting pre-determined thresholds, similar to the conduct and impact approach, ERCOT's market power mitigation cannot be defined as purely belonging to none of the two main approaches previously discussed. The two-step approach divides constraints into "competitive" constraints and "non-competitive" constraints through a constraint-by-constraint evaluation.[31] Constraints are evaluated on annual and monthly bases using a procedure based on the Herfindahl–Hirschman index (HHI) and the shift factors of generators to constraints. Usually but with some exceptions, the constraints that are evaluated to be competitive in ERCOT roughly correspond to the inter-zonal constraints in the previous zonal market, while all other constraints are evaluated to be non-competitive. The following represent the two steps:

[28] See `https://www.potomaceconomics.com/markets-monitored/ercot/`.

[29] For 2019 see: `https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf#page=117&zoom=100,93,514`.

[30] Substantive rule 25.505 originally set the cap at 3,000$/MWh, adjusted to 5,000$/MWh in 2013, and 7,000$/MWh in 2014.

[31] As with other structural MPM designs this approach does not account for the interaction of multiple binding constraints.

- Step 1: the system is optimally dispatched with only competitive constraints enforced and no mitigation mechanism in place(except system-wide offer cap and system-wide offer floor). This run provides nodal "reference LMPs" that are used in the next stage. This first step is basically used to set LMPs or reference prices for each resource node based on power balance and enforcement of the "competitive" constraints within the ERCOT transmission network;

- Step 2: the system is then optimally dispatched with all constraints enforced and with each resource's offer mitigated to the greater of the Reference LMP (from Step 1) at the resource's node or its pre-specified mitigated offer cap (MOC) and bounded at the lesser of the Reference LMP (from Step 1) at the resource's node or the appropriate mitigated offer floor. If no non-competitive constraint is binding, then results of Step 2 are exactly the same as those of Step 1. Thus, any change in Step 2 from Step 1 is due to the need to resolve non-competitive binding constraints and is resolved using pre-defined mitigated offer curves (Siddiqi, 2007).

The rationale is that if there is zonal-wide scarcity then the reference prices in the first stage will be high, allowing for high prices in the second stage. On the other hand, if there is not zonal-wide scarcity, then offers will be mitigated for the second stage. As with structural tests, this approach will certainly limit prices. However, in circumstances of intra-zonal, that is, local scarcity it could result in prices that are below competitive levels.

4.4.2 Mitigated Offer Cap (MOC)

MOC are pre-determined reference levels for each resource that are applied in the second of the two-step process (Patterson, 2019). These offer caps, specific for each unit, are based on several factors being a function of:

- Generic incremental heat rate: for generation resources with a commercial operations date on or before January 1, 2004, the generic incremental heat rate shall be set to

10.5. For generation resources that have a commercial operations date after January 1, 2004, this value shall be set to 14.5.

- Incremental heat rate per resource: the verifiable incremental heat rate curve for resource as approved in the verifiable cost process
- Natural gas price index
- Fuel index price percentage: the percentage of natural gas used by each resource to operate above LSL (low sustained limit, i.e., the minimum sustained energy production capability of a resource, as submitted with the energy offer curve
- Fuel oil price index
- Fuel oil price percentage: the percentage of fuel oil used by each resource to operate above LSL, as submitted with the energy offer curve
- Solid fuel price: the solid fuel index price is $1.50.
- Fuel price calculated per resource: the calculated index price for fuel for each resource based on the resource's fuel mix
- Adder: The fuel adder is the average cost above the index price each resource has paid to obtain fuel
- Operations and maintenance (O&M) cost above LSL: the O&M cost for each resource to operate above LSL, including an adjustment for emissions costs, as approved in the verifiable cost process
- Factor multiplier: a multiplier based on the corresponding monthly capacity factor
- Average fuel price: the volume-weighted average intraday, same-day and spot price of fuel submitted to ERCOT during the Adjustment period for a specific resource and specific hour within the operating day

4.5 New York ISO (NY-ISO)

NYISO has an internal and an external market monitor. The internal market monitor is named the Market Monitoring Unit while the external market monitor is Potomac Economics.[32] Potomac is the provider of market monitoring services for many ISO's across the US including, as will be seen in the next paragraphs ISO-NE, ERCOT and Midwest-ISO. It's responsible for evaluating the performance of the markets and identifying attempts to exercise market power. Every year the external monitor publishes a detailed report on NY-ISO's "State of the market" in which the competitive performance of the market is evaluated, (ii) highlighting patterns of potential economic and physical withholding and (ii) analyzing the use of market power mitigation measures. An important measure that is used by Potomac to assess competitiveness of the ISO is the so called "output gap": the output that is economic at the market clearing price at that location but is not produced because the supplier's offer parameters (economic or physical) exceed the reference level threshold for uneconomic production.

NYSO applies a Conduct and Impact approach[33] in deploying its market mitigation measures. So, different to what previously showed with CAISO and PJM, where the structure of the relevant market to a binding constraint is evaluated, in the case of NYISO other elements are tested to assess competitiveness of offers. First, the behavior (Conduct) of market participants is tested comparing it to a defined threshold. Second, if the Conduct test is failed, the impact of that market participant's behavior on market clearing prices is tested. Again, if the impact on equilibrium prices is higher than a given threshold the offer that failed the test is mitigated to a pre-determined reference level. Three types of conduct are, according to NYISO, are considered in contrast with workable competition:

- Economic Withholding: a unit submitting bids that are unjustifiably high so that (i)

[32] A private company that provides independent market monitoring, expert analysis and advice, custom software solutions, and litigation support services to the electricity and natural gas industries.

[33] For more details see NYSO Tariff BP Manual at `https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariff.pdf` and Attachment H - ISO Market Power Mitigation Measures.

the Electric Facility is not or will not be dispatched or scheduled, or (ii) the Bids will set a market clearing price.

- Physical Withholding: a unit not offering to sell or not scheduling the output that it would be able to sell by (i) falsely declaring out of service, (ii) refusing to offer when it would be against its economic interest, (iii) making an unjustifiable change to one or more operating parameters of a Generator that reduces its ability to provide Energy or Ancillary Services, (iv) operating generators in real time at a lower output that it should have if it followed the ISO'S dispatch instructions.

- Uneconomic production: a unit is increasing the output to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

4.5.1 Economic Withholding

Both the conduct and the impact thresholds vary across the market depending on the location of the tested unit. A resource located in areas defined as "Constrained areas" will face more strict thresholds than units located in "Unconstrained Areas"[34]. Constrained Areas are (a) the In-City areas, including any areas subject to transmission constraints within the In-City area that give rise to significant locational market power; and (b) any other area in the New York Control Area that has been identified by the ISO as subject to transmission constraints that give rise to significant locational market power. More technically, a resource is defined as located in a Constrained area if the interface or facility into the area in which it is locates has a shadow price greater than 0.04 USD/MWh. Any resource located in an area that does not meet the previous definition is assumed to be located in an Unconstrained Area.

In areas defined as constrained, the Conduct test verifies if a particular resource's energy offer is above its reference level by more than a given threshold. The offer price P_i for energy[35] will fail the Conduct test if $P_1 > \text{Reference Level}_i(1 + \frac{2\%\text{Average Price8760}}{\text{Constrained Hours}})$, where the

[34]New York City is the most frequently area included in the set of constrained areas.
[35]Energy and Minimum Generation Bids.

average price is the average price in the Day-Ahead Market (or Real-Time Market) in the Constrained Area over the past 12 months, adjusted for fuel price changes and adjusted for out-of-merit generation dispatch; and *Constrained Hours* is the total number of minutes over the prior 12 months, converted to hours (retaining fractions of hours), in which the real-time shadow price has been greater than 0.04 USD/MWh.

This threshold is designed to be less strict towards producers when constrained hours drop and when the average market price increases.[36] If the offer fails the Conduct test, then the Constrained Area Impact test is applied. This last step verifies if the offer increases the equilibrium price (with i's impact) P_{ei} by an amount greater than the conduct threshold $P_{ei} > P_e(1 + \frac{2\%\text{Average Price}8760}{\text{Constrained Hours}})$.

In Unconstrained Areas the threshold is less stringent. Incremental energy and minimum energy bids fail the Conduct test if they exceed its resource's reference level by the lower between 100 USD/MWh or 300 percent.[37] An offer below 25 USD/MWh shall be in any case deemed not to constitute a conduct above the competitive threshold. The Impact test verifies if the offer raises the clearing price by more than the lower between 100 USD/MWh and 200 percent. If the Unconstrained Area Threshold is lower than the constrained area threshold than the former is applied also to resources located int the Constrained Area. NYISO also has a 1,000 USD/MWh offer cap on incremental energy offers.

4.5.2 Physical Withholding and Uneconomic Production

For physical withholding, as seen for economic withholding, different thresholds are set depending on the location of the tested unit. In Unconstrained Areas[38], unit's conduct is addressed as physical withholding if withholding exceeds: (i) 10 percent of a Generator's capability, or (ii) 100 MW of a Generator's capability, or (iii) 5 percent of the total capability of a Market Party and its Affiliates, or (iv) 200 MW of the total capability of a Market

[36]For start-up bids the threshold is set to 50% above the reference level.

[37]Start-Up Bids: A 200 percent increase; Operating Reserves and Regulation Capacity Bids: A 300 percent increase or an increase of 50 USD per MWh.

[38]The definition of Constrained/Unconstrained Areas is the same for economic and physical withholding.

Party and its Affiliates. For units located in Constrained areas thresholds are more strict including withholding that exceeds: (i) 10 percent of a Generator's capability, or (ii) 50 MW of a Generator's capability, or (iii) 5 percent of the total capability of a Market Party and its Affiliates, or (iv) 100 MW of the total capability of a Market Party and its Affiliates. In real-time, operating a generator at an output lower than the one expected given the ISO's dispatch instructions is also subject to mitigation. That is for Unconstrained Areas a difference in output that exceeds (i) 15 minutes times the Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates and for Constrained Areas (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 50 MW of a Generator's capability, or (iii) 100 MW of the total capability of a Market Party and its Affiliates. Impact thresholds are the same seen for economic withholding.

A conduct is considered uneconomic production if energy is scheduled at an Locational Based Marginal Price (LBMP)[39] that is 20 percent lower than the applicable reference level and causes or contributes to transmission congestion or in real time unit is running a generator at an output higher than expected given the dispatch instruction of the ISO causing or contributing to create congestion. In this last case the same thresholds seen for physical withholding in Unconstrained Areas are applied.

4.5.3 Reference Levels

NY-ISO uses reference levels that can vary depending on the output range and on the type of offer that needs mitigation (incremental energy, start-up cost, economic minimum etc.). In general, the market monitoring units uses three types of reference levels in the following order of preference and subject to the existence of sufficient data:

[39]LBMP is the NY-ISO version of the locational marginal price.

- Offer-based: calculate reference levels based on the mitigated unit's accepted offers during competitive hours of the previous 90 days (the value may be adjusted for fuel prices).

- LMP-based: compute reference levels based on the mean of the LBMP at the Generator's location during the lowest-priced 50 percent of the hours that the Generator was dispatched over the most recent 90 days period. To avoid outliers, NYISO may exclude very low prices and adjust for fuel prices.

- Cost-based: determined in consultation and based on the resource's documented marginal costs defined as (heat rate $*$ fuel costs) + (emissions rate $*$ emissions allowance price) + (other variable operating and maintenance costs).

4.6 Midwest ISO (MISO)

The Midcontinent Independent System Operator, Inc., formerly named Midwest Independent Transmission System Operator, Inc. is an Independent System Operator (ISO) and Regional Transmission Organization (RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets. In its Market Monitoring Business Practice Manuals, MISO defines market power as the ability to raise Locational Marginal Prices, Market Clearing Prices, or Auction Clearing Prices for Planning Resources significantly above competitive levels.[40] The goal of Market Monitoring and Mitigation (MMM) is to prevent the distortion of competitive outcomes while avoiding unnecessary interference with competitive price signals. As seen in NY-ISO, MISO categorizes three types of conduct that may warrant mitigation: physical withholding, Eco-

[40] This definition is different from the usual antitrust definition which is "raise price and profit from this price increase." The MISO definition says nothing about raising the price leading to higher or lower profits.

nomic withholding, Uneconomic production[41] (for definitions see previous section). MISO employs a two-part test (Conduct Test plus Impact Test)[42] to determine whether mitigation is warranted. These tests are designed to establish whether an exercise of market power substantially distorts market outcomes before Mitigation Measures are imposed. As in the case of PJM, there is no proper internal market monitor unit within this ISO. The independent marker monitor (IMM) is the entity retained by MISO to impartially implement the market monitoring plan reporting directly to the board of directly. The designated entity currently is Potomac Economics. The internal Market Monitoring Liaison Officer has no active role in implementing mitigation measures but is more a coordinator of the IMM: supporting the data flow towards the IMM, ensuring that the IMM's mitigation instructions are properly carried out and guaranteeing the independence of the IMM.The external IMM carries out each year an extensive analysis including competitive assessment of the MISO markets, a review of market power indicators, an evaluation of participant conduct and a summary of the use of market power mitigation measures. The "output gap" metric was used to assess competitiveness of market outcomes (especially for economic withholding). The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount.

4.6.1 Transmission Constrained Areas

In MISO, mitigation measures are only applied in response to the presence of Binding Transmission Constraints, local reliability constraints, operating reserve requirements or reliability needs or other market design that impede competitive operation. The Conduct and Impact thresholds in MISO depend on whether a resource is located in a Narrow-Constrained Area (NCA, or DNCA in the case of Dynamic Narrow-Constrained Areas) or a Broad-Constrained

[41] Also Uneconomic Virtual Transactions may contribute to an unwarranted divergence between LMPs in the Day-Ahead and Real-Time Energy and Operating Reserve Markets if they are used to create congestion in the Day-Ahead Energy and if they cannot be justified based on risk management or other economic considerations.

[42] See Business Practices Manual 009 - Market Monitoring and Mitigation, `https://cdn.misoenergy.org/DRAFT\%20BPM\%20009\%20Market\%20Monitoring\%20and\%20Mitigation_Clean289165.pdf`.

Area (BCA). The former are areas in which transmission constraints are chronic and isolate narrow market areas with a limited number of suppliers, enabling at least one supplier to have significant market power. Some of these are long-lasting due to intact system topology (NCA), while others are unanticipated and transitory, often associated with transmission or generation outages (DNCA). In BCAs constraints isolate market areas that are broader and contain a larger number of suppliers and are often transitory. More formally:

- Narrow Constrained Areas (NCA): is an electrical area where (i) one or more binding transmission constraints or binding reserve constraints are expected to be binding for more than 500 hours during a given twelve-month period and (ii) at least one supplier is pivotal[43] in the electrical area.

- Dynamic Narrow Constrained Areas (DNCA): is an area where binding transmission constraints are not expected, or not yet determined, to be sustained for a period long enough to identify it as an NCA, where (i) binding transmission constraints into area have been binding for at least 15 percent of the hours in a continuous five-day period prior to the current period[44] and (ii) the conduct and impact tests applicable to DNCAs have been met by at least one supplier.

- Broad Constrained Areas (BCA): are areas in which the presence of constraints generally does not result in market power because the market remains competitive due to the large number of available suppliers in that area. However, under high load conditions or unusual transmission/supply conditions (outages), opportunities to exercise market power may rise also in BCAs. Differently from NCAs and DNCAs, BCAs are not identified in advance by the IMM. In BCAs, market power concern is related to

[43] As for other ISOs, MISO defines a supplier as pivotal when the output of some of its Generation Resources must be increased or decreased to resolve a Binding Transmission Constraint during some or all hours when the constraint is binding. The IMM uses transmission Load flow cases reflecting a variety of market conditions to determine whether a supplier is pivotal. These Load flow cases estimate the Generation Shift Factors (GSFs) for all Generation Resources relative to each potentially constrained flowgate, the base flows on each flowgate, and the base loadings of Generation Resources.

[44] Or the IMM identifies the initiation of an outage or re-occurring condition that previously has caused the binding of at least 15 percent of hours in a five-day period.

specific load conditions and outages and, thus, BCAs are defined dynamically when constraints arise on any Flowgates in the MISO Region. Not all resources are included in the identified BCA. A positive and negative Constraint Generation Shift Factor Cutoff (CGSFC)[45] is specified by the IMM to identify Generation Resources that will be included in a BCA. Default levels of +.06 and −.06 will be used as the positive and negative CGSFCs for all Flowgates, except for those for which FERC has approved different CGSFC values. The CGSFC values establish the thresholds that determine which Generation Resources have a relatively large effect on the corresponding Flowgate. A Generation Resource is considered to have a significant effect on the Flowgate if the value of its GSF (which may be either positive or negative) is outside the range of the Flowgate's positive and negative CGSFC values.

4.6.2 Conduct Thresholds

Different thresholds are established for NCAs and BCAs for economic and physical withholding. In NCAs, a conduct is deemed to constitute physical withholding if any of the following conditions occur:

1. Taking an unapproved derating or outage,
2. Refusing to provide generation offers or schedules when capable of providing service,
3. Falsely declaring a generation resource as derated, unavailable or forced out-of-service.

In an NCA, all instances of physical withholding of Generation Resources, as defined above, are automatically subject to Impact Testing and possible mitigation. Thus, in an NCA, the Conduct Threshold for physical withholding may be considered to be any of the above behaviors.

In Broad Constrained Areas, thresholds are less stringent and in addition to the NCA thresholds also one of the following thresholds must be exceeded:

[45] These are similar to the DFAX seen in the PJM context (PTDF in the CAISO paragraph): they measure the influence of a generation unit on power flows between two nodes of the network.

1. Withholding more than the lower of 200 MW or 5% of the total capability owned or controlled by an MP and its Affiliates in the BCA.

2. Operating a Generation Resource in real-time at an output level that is less than 90% of MISO's instructions.

These conditions do not apply to NCAs nor they apply to BCAs in absence of a binding transmission constraint. Different conditions are set for economic withholding. In particular, in Broad Constrained Areas, where sufficient competition usually exists or where the transmission constraints bind infrequently, the conduct thresholds are determined with respect to the reference levels for each supplier (see the five methods to calculate reference levels in MISO in the dedicated section). Since transmission constraints in BCAs do not normally bind frequently, the thresholds are only applied to significant instances of locational market power when one or more Transmission Constraints are binding. As described earlier, this occurs in BCAs only for suppliers whose generation shift factors are outside the range of the positive and negative CGSFCs for a Flowgate with a binding constraint. A conduct will fail the Broad Constrained Area conduct test if any of the following conditions occur and results in causing a binding constraint: 1) Energy and Minimum Generation Offers: A 300% increase (4 times) or a 100 USD per MWh increase above the Reference Level, whichever is lower. Energy Offers or minimum Generation Offers below 25 USD per MWh are not considered economic withholding. 2) Start-Up Offers: A 200% (3 times) increase above the Reference Level. This applies to the cold start-up Offer, intermediate start-up Offer or hot start-up Offer, whichever is applicable to the specific start-up time of the Generation Resource.[46]

In designated NCAs where transmission constraints are expected to be binding for more than 500 hours per year and suppliers are pivotal, conduct thresholds for Energy and minimum generation offers are more restrictive. Conduct Thresholds are lower for NCAs than

[46] Other thresholds are set also for offers expressed in units other than dollars (for example time-based offers) both for BCAs and for NCAs.

for BCAs because NCAs are constrained more frequently and are more likely to have the conditions conducive to market power. Once an area is designated as an NCA, the issue of whether any specific supplier is pivotal when conduct is being tested is no longer pertinent. Pivotal suppliers contribute to the initial determination of an NCA but any supplier, regardless of whether it is pivotal, may be subject to mitigation for conduct in an NCA.

The following thresholds (expressed in terms of reference levels) are effective when one or more interfaces into the NCA being tested has a binding transmission constraint:

1. Energy and Minimum Generation Offers: An increase in the energy offer or minimum generation offer above the applicable Reference Level by more than the Conduct Threshold as determined with the following formula: NCA Conduct Threshold = $\frac{\text{Net Annual Fixed Cost}}{\text{Constrained Hours}}$, where Net Annual Fixed Cost is the annual fixed costs of a new peaking Generator (USD/MW), including recovery of annualized (USD/MW) capital costs. Constrained Hours are the total number of hours over the prior 12 months during which a Binding Transmission Constraint has occurred on any Interface into the NCA in which the Generation Resource is located, but not more than 2000 hours. Note that an NCA Conduct Threshold declines (becomes more restrictive) when the number of constrained hours increases for that area since market power is likely to be more severe in areas that experience more frequent constraints.

2. Start-Up Offers: A 50% (1.5 times) increase above the Reference Level. This applies to the cold Start-Up Offer, intermediate Start-Up Offer or hot Start-Up Offer, whichever is applicable to the specific start-up time of the supplier.

Thresholds are applied also to identify different categories of uneconomic production that may warrant the imposition of a mitigation measure.

4.6.3 Impact Thresholds

In order to avoid unnecessary mitigation, default bids are not applied if the above described conducts do not cause a substantial change in clearing prices. It is necessary to incorporate Impact Tests as the second component of the trigger for mitigation because conduct that does not have a significant effect on market outcomes is not deemed a sufficiently large exercise of market power to be worthy of being mitigated.

Also, for impact thresholds, BCAs and NCAs are taken into consideration:

- Broad-Constrained Areas: a price impact equal to an increase of 200% (3 times) or 100 USD per MWh, whichever is lower, in an hourly Day-Ahead or Real-Time Energy LMP at any location in that BCA.

- Narrow-Constrained Areas: a substantial price effect on an LMP in an NCA is as follows NCA Price Impact Threshold = $\frac{\text{Net Annual Fixed Cost}}{\text{Constrained Hours}}$, where Net Annual Fixed Cost are Annual fixed costs of a new peaking Generator (USD/MW), including recovery of annualized (USD/MW) capital costs; and Constrained Hours the total number of hours over the prior 12 months during which a Binding Transmission Constraint or Binding Reserve Zone Constraint has occurred on any Interface into the NCA in which the Generation Resource is located, but not more than 2000 hours.

Failure of the Price Impact Test in an NCA affects all Generation Resources that have failed their NCA economic withholding Conduct Test for that hour in that NCA and have GSF smaller CFGSFC in the binding NCA constraint.

4.6.4 Reference Levels

If a unit's offer exceeds both Conduct and Impact threshold, then its offer is replaced with the applicable reference level (default bid). In MISO, five ways are identified to calculate reference levels (in preferred rank order):

1. Offer-Based: the lower of the mean or the median of a Generation Resource's accepted Offers or Offer components in competitive periods (i.e., when transmission constraints are not binding) over the previous 90 days separately for Peak and Off-Peak periods and, for the Real-Time and Day-Ahead Energy and Operating Reserve Markets, adjusted for changes in spot fuel prices.[47]

2. LMP-Based: The mean of the LMP or applicable MCP at the Generation Resource's location during the lowest-priced 25% of the hours that the Generation Resource was dispatched over the previous 90 days for Peak or Off-Peak periods, adjusted for changes in fuel prices.[48]

3. Cost-Based (Consultative): a level determined in consultation with the ISO submitting the Generation Offer and intended to reflect a Generation Resource's marginal costs, including prudent risk premiums and opportunity costs, or justifiable technical characteristics for physical Offer parameters, provided that this consultation is done prior to the occurrence of the conduct being examined.

4. Estimated: The IMM's estimate of the variable production costs of the Generation Resource (or the technical characteristics of the Generation Resource for physical Offer parameters), taking into account available operating cost data, appropriate input from the MP, and the best information available to the IMM.

5. Averaged: An appropriate average of competitive Offers of one or more similar suppliers.

[47] Offer-based Reference Levels are particularly applicable for Generation Resources that are dispatchable (i.e., whose output level is determined by the LMP market), where competitive conditions prevail in most hours, providing a strong incentive for suppliers to offer competitively (at or close to their marginal costs).

[48] LMP or MCP-Based Reference Levels are particularly applicable for Generation Resources that are self-scheduled or that act as price-takers in the Real-Time Energy and Operating Reserve Market.

4.7 Key Takeaways

Among the different market power mitigation (MPM) mechanism designs that have been described in this paragraph, some key aspects can be highlighted. The structural approach appears to be more complex than the "conduct and impact" approach—both in terms of implementation and operation of the MPM tool. On the other hand, the "conduct and impact" approaches seem to be tailored to the specific features of the electricity market under consideration. The three pivotal supplier test has more universal and adaptable features that makes it preferable if compared to just setting thresholds.

A market power mitigation mechanism based on offer price and market impact thresholds has the obvious problem of tolerating the exercise of unilateral market power up to these thresholds. Suppliers that can keep their offer prices just below the mitigation threshold. This can allow the exercise of a small amount of market power that can add up over the 8,760 hours of the year. Suppose the conduct threshold was set at 2 USD/MWh above a certain reference level. The test would mitigate one offer that exceeds the threshold by 8,760 USD but not 8,760 offers that during the course of the year exceed each the threshold by 1 USD. In this case, the economic "damage" for the system would be the same but the Conduct and Impact approach would mitigate only the first case and not the second. The structural approach has the potential to catch all of these instances because it mitigates offers if the supplier is determined to have a significant ability to exercise to exercise unilateral market power.

For this reason, the Structural approach seems more adaptable to different market conditions. It does not evaluate the specific conduct of a market participant but the ability and incentive to exercise market power based on the structure of the local market, recognizing if a supplier has a substantial ability to exercise unilateral market power it will exploit this ability and set higher prices. It is significantly more difficult for market participants to adapt their conduct to avoid mitigation because the three-pivotal-supplier test does not evaluate their conduct but their ability to influence market prices based on the local market structure.

5 Challenges to Developing a MPM Mechanism for a Low Carbon Electricity Market

In this Section, we discuss several potential issues related to market power mitigation mechanisms that may even become more important in a less carbon intensive electricity supply industry with a larger share of intermittent renewables. We do not claim completeness of the issues discussed below. The major focus of these issues is on short-term market performance. Electricity systems are complex and whether an issue will be important typically depends on a combination of several factors. For example, an increase in solar photovoltaic (PV) capacity may increase the ability of dispatchable units to exercise unilateral market power in hours when the sun sets because only a limited number of these units are able to ramp up that fast. In a different setting, say in a market flexible supply from storage, handling the same amount of solar PV capacity might not be problem because owners storage may be willing to shift demand throughout the day implicitly constraining the ability of dispatchable resources to exercise unilateral market power.

5.1 Technical Parameters and Intertemporal Market Power of Conventional Units

Most countries around the world have already added or are planning to add large shares of intermittent renewables to their energy mix. These technologies have the advantage that they have almost zero marginal costs of production and every MWh can be produced without any emissions. Unfortunately, these technologies can provide some challenges for the power system especially if significant amounts storage or demand response are absent. Seasonality, intermittency, and limited controllability of the output profiles of renewables cause these challenges. Consequently, conventional units may have to adjust their output profiles more frequently and also higher reserve requirements are needed. In such a case operational parameters of conventional power plants such as the minimum stable production limit, minimum up-time and minimum down-time, or ramp-rates will become more important and market participant's may exercise unilateral market power by miss-reporting their technical parameters (see, e.g., Oren and Ross, 2005).

Monitoring the ramp rate may be particularly important in power systems with a large amount of solar capacity because there will be a considerable demand for flexible resources being able to ramp-up quickly when the sun sets. At the moment CAISO does not apply inter-temporal market power mitigation tests to account for the demand for ramping. However, resources dispatched down or up at full ramp rates are settled at there offer price at the start of the ramp period.[49]

From a regulatory perspective, the interactions between intermittent renewables that may translate into a more volatile net demand[50] for partially inflexible dispatchable units may put more importance to ancillary services rather than to the production of energy. Therefore, market power may be an issue in the markets for ancillary services. Related to the issue of net demand as well as the demand for ancillary services is predictability of the output of distributed intermittent resources such as rooftop and community solar and wind facilities as these will be a factor in determining (i) the demand for reserves and (ii) the net demand for dispatchable units operating on the grid.

Because dispatchable resources must operate to meet the net demand, operational constraints on these units such as commitment costs and minimum operating level costs will become increasingly relevant and are therefore an additional avenue for suppliers to exercise unilateral market power. They can alter their offers for start-up costs and minimum operating levels costs to increase the revenues they receive when they know a unit must operate. The CAISO is currently the only ISO in the US that does not allow for market-based commitment cost offers. These offers cannot be higher than 125% of the CAISO's estimate of the fuel cost for the start-up costs and minimum operating level costs of the unit. How-

[49]See Section 5.2.5. in Commitment Cost and Default Energy Bid Enhancements, Revised Draft Final Proposal, January 31, 2018 published by CAISO.

[50]The net demand is the demand net of the output from renewables that must be served by dispatchable units.

ever, CAISO is currently implementing changes in their tariff that will allow market-based commitment cost bids.[51] that will also be subject to market power mitigation if deemed noncompetitive.

5.2 Market Interactions

All US market power mitigation mechanism treat input fossil fuel costs as exogenous to the behavior of the generation unit owner. This logic has led a number of US markets to use input fuel prices from formal markets as the input fuel cost used to set a generation unit's reference price. Similar issues arise with respect to the cost of CO_2 emissions allowances. Consequently, multi-market interactions may become an issue in certain markets depending on the industry structure.

5.3 Storage and Demand Response

Storage, or more inclusively, any kind of energy-limited technology will base its decision to operate based on an opportunity cost logic. Opportunity cost is the value of the next best alternative forgone as a result of selling/buying energy on the market. Because opportunity cost is a function of scarcity, market participants with technical limitations are faced with trade-offs in how they use their limited resources. For example, a storage unit will optimize its offer behavior over multiple periods depending on its capacity to store and electricity as well as its capacity to charge and discharge. These parameters as well as the expected *opportunities* in form of counter-factual market prices within the optimization horizon will determine its opportunity cost.

The operating characteristics of energy-limited resources such as storage should be explicitly considered by the ISO (or market monitor) in order to determine the opportunity costs of these resources, which, in turn, justify their competitive reference levels. To prop-

[51] See Commitment Cost and Default Energy Bid Enhancements (CCDEBE), Revised Draft Final Proposal, January 31, 2018. Part of the proposal is currently in the implementation phase, see `http://www.caiso.com/StakeholderProcesses/Commitment-costs-and-default-energy-bid-enhancements`.

erly mitigate and monitor hydro storage units it is important for an ISO to gather all the information related to regulatory, environmental, technical or other restrictions, or other operating characteristics that limit the resource availability or run-time. This information must be used when a mitigation action takes place.

In the PJM Interconnection hydro generation units submit data to the Office of Interconnection to determine their available operating hours. In CAISO, historical data is reviewed together with the explanation of why the resource has operating limitations. When the energy-limited resources bid into the CAISO market, they must provide the daily energy limit so that the CAISO can know when and how to schedule, dispatch and eventually also mitigate them.

The ISOs that use the more sophisticated structural approach to mitigate market power such as CAISO or PJM have only recently started a deeper consideration of the particularities of storage resources when it comes to market power mitigation. PJM's Cost Development Guideline provides an explanation on how it would quantify opportunity cost adders for resources with economic, regulatory, and non-regulatory restrictions. Broadly speaking, its methods rely on forward gas and electricity prices, which could be based on daily or longer-term forward prices. CAISO requires suppliers to submit their opportunity cost data as part of their requests to have negotiated rates as their default mitigation bids.

We expect that the options to store electricity will increase and so will be the number of units operating based on an opportunity cost logic. As of today the majority of storage units make use of mechanical potential energy, e.g., pumped-hydro storage units. However, other options such as thermal storage, chemical storage using batteries or by electrolysis of water in combination with gas storage, or by shifting consumption to a later period will be more widely available in the near future. Electrolysis of water also known as power-to-gas, hydrogen, or renewable gas, has been uneconomic for a long time. However, in a world with large share of almost zero variable cost renewables there may be many periods with excess supply that can be used to transform electricity to gas accepting the inefficiency in the transformation because at least electricity that otherwise would have been curtailed and therefore wasted can be made use of. We refer to Glenk and Reichelstein (2019) on the economics of power-to-gas. The authors find that renewable hydrogen in Texas and Germany is already cost competitive in niche applications and expect that it will become more competitive within a decade provided recent market trends continue in the coming years. California will have spent about 230 million USD on hydrogen projects by the end of 2023 and envisions 50,000 hydrogen light-duty vehicles by middecade and a network of 1,000 hydrogen stations by 2030.[52] Given this development, opportunity cost logic will become more prevalent in future market power mitigation mechanisms but may also lead to a further integration of electricity and gas markets which may enforces the points made in Subsection 5.2 on market interactions.

Agreeing on variable costs of production can already be a challenge and shifting more generation capacity to opportunity cost logic will increase the challenge to agree on competitive reference levels.[53]

5.4 Monopsony Power in Two-sided Markets

An under-researched topic in electricity markets is the role of the demand side. Vertically integrated electric utilies monoplies but also monompsonies if they are single buyers of wholesale power within a geographically restricted area, namely their service area Wilson et al. (2020). Vertically integrated utilities tend to use this market power to lower prices and eliminate other sellers. In the long run this allows the vertically-integrated monopsonist to favor it's own generation in the supply side. Wilson et al. (2020) assert that monopsony is even more difficult to resist than monopoly and that regulators tend to overlook monopsony power issues for many reasons. First because they tend to analyze monopsony using monopoly-designed tools. Furthermore, utility regulators tend to underestimate the poten-

[52] See `https://www.nytimes.com/2020/11/11/business/hydrogen-fuel-california.html`.

[53] More details on the discussion of how to set reference values for storage units can be found in Bushnell et al. (2019, 2020) and Local Market Power Mitigation Enhancements, Revised Straw Proposal, November 16, 2018.

tial for monopsony to result in higher prices on final consumers and the harm that it may cause to sellers of power generation (usually not in the regulator's primary interest).

5.5 Unilateral Market Power Tests

The structural market power mitigation tests rely on joint pivotality. For that reason, they are a crude measures of the ability of a supplier to exercise unilateral market power because they do not take in account the elasticity of a firm's residual demand curve. An alternative option would be to derive firm-level residual demand curves and calculate their best response offer-curves given market conditions and each firm's level of open forward contract positions at the time of offering to e.g., the day-ahead market. Wolak (2007) presents such an approach for a single-zone market. In Graf and Wolak (2020) this residual demand curve concept is extended to locational pricing markets. The downside of this approach is the computational complexity. However, that may be resolved in the near future given the continuous progress in computational capacity.

5.6 Voltage and Stability Security Constraints

All the market power mitigation mechanisms discussed in this paper are designed to detect and address the potential exercise of unilateral market power in local markets created as a consequence of a limited transmission capacity (e.g., if the "active power" transmission capacity of one or more grid elements is not able to accommodate energy demand for a given location using the cheapest supply resources available in the system, the market algorithm is forced to activate local resources to meet the demand and avoid any grid overload). These constraints are also affecting, by definition, Locational Marginal Prices obtained as a result of the market-clearing.

In practice, system operators have to deal with a wider set of operational security parameters to ensure the security of the power system and the quality of supply, including voltage (e.g., the voltage level at any given bus of the network shall respect proper lower and upper limits to avoid voltage collapses or dangers to grid devices) and stability constraints (e.g., after any single unplanned event, the inertia of the system together with the reaction of available resources shall be able to contain the frequency and voltage deviation from the nominal values).

In the past, voltage and stability issues were less relevant in the system operation than they are today. An energy mix largely based on conventional, dispatchable and regulating power plants (e.g., thermal generation units) supports voltage and frequency management. Voltage and stability issues are becoming more and more relevant due to an increasing share of intermittent renewable energy sources. Hence, dedicated constraints shall be included in the market clearing algorithm to ensure the outcomes are compatible with the real-time system operation. Considering that typically (for limiting the computational burden of the algorithms) a DC approximation of the Security Constrained Unit Commitment and Optimal Power Flow[54] problem is applied in standard market software, voltage and stability constraints have to be implemented in form of minimum number of regulating power plants to have online in a given area of the network and/or using the so called Reliability Must Run (RMR) units (units which are dispatched out of merit order to provide ancillary services).

These non-convex constraints are not tackled by the existing MPM systems: in the structural approaches, only linear transmission constraints are investigated, while conduct and impact approaches fail to tackle these cases because these non-convex constraints do not imply a higher Locational Marginal Price (e.g., if a unit is dispatched out of merit order for ensuring the voltage value at the busses are in the ranges and no overloads are detected in the

[54]The goal of the Optimal power flow (OPF) problem—introduced by J. L. Carpentier (Carpentier, 1962, 1979)—is to find optimal dispatch given exogenous levels of (locational) demand minimizing the total cost of production and satisfying all power flow constraints and power-plant output constraints at the same time. Alsac and Stott (1974) extended the OPF problem to account for security constraints used to check and solve also potential breaches of the operational security limits after the occurrence of any single contingency in system. The most complex and wide formulation of this problem is the Alternate Current SCOPF (AC SCOPF) that simultaneously cope with active and reactive power, ensuring also a proper control of voltage profiles. However, the full AC SCOPF is a highly complex non-linear problem which still today is hard to solve in a robust and fast way. For this reason, typically a the Direct Current approximation (DC SCOPF) is adopted in market operation, assuming all buses are operating at their nominal voltage value. An overview on the state of the art of OPF solving techniques can be found in Cain et al. (2012), Capitanescu et al. (2011), and Capitanescu (2016).

system, the locational marginal price will be defined by the cheapest MWh in the system and not by the energy offer of the out of merit order unit). For this reason, RMR units are often contracted outside the market (fixing their prices/costs) or other more stringent approach are adopted (e.g., in CAISO all the start-up and minimum load cost offers are mitigated). Considering the ambitious renewables targets expected to be meet in the next decade, voltage and stability constraints are expected to play a crucial role in determining the optimal dispatch solution. For this reason, further investigations are probably needed to expand existing MPM processes in order to explicitly and fairly tackle these points.[55]

5.7 Market Power Mitigation and Investments Incentives

Market power mitigation processes play a crucial role in avoiding potentially large money transfers from consumers to producers due to the exercise of unilateral market power. This role is vital in ensuring the short-term efficiency of the wholesale electricity markets. However, if deployed too strict, MPM could excessively smooth down (locational) price signals raising from the markets, lowering incentives for demand side response (including storage) or for investing in grid and/or generation expansions. Here, the role of the reference levels is crucial: they should be low enough to avoid suppliers can excessively profit from exercising market power, but they should allow for high prices that reflect scarcity conditions. This has been extremely challenging aspect of the design of market power mitigation mechanisms and different markets handle this differently.

5.8 Forward Energy Market Transparency and Liquidity

Fixed price forward contract obligations play an important factor limiting the exercise of market power by suppliers in the short-term market. As demonstrated in Wolak (2000), a supplier with a fixed price forward contract obligation is a net buyer of energy in the short-

[55]In the medium term, many of these issues can be fixed by upgrading the power grid, e.g., by installing asynchronous compensators. However, in the short-run they may still be very relevant as they will lead to locational markets.

term market for this quantity of energy. Therefore, as Wolak (2021) notes, even a supplier with a significant ability to exercise unilateral market has an incentive to offer this quantity of energy into the short-term market at marginal cost in order to make the least-cost make versus buy decision for this amount of energy. In virtually all regions, these long-term contracts are traded in the non-transparent bilateral markets. This can disadvantage small suppliers and load-serving entities as well as new entrants to the generation and retailing sectors. Consequently, Wolak (2021) argues for establishing a centralized market for standardized fixed-price forward contract to increase both the transparency and liquidity of forward markets for energy. Wolak (2021) outlines how this centralized market for standardized fixed-price forward contracts can be used as the foundation for a long-term resource adequacy mechanism.

6 Concluding Comments

A key takeaway from our survey of automatic market power mitigation mechanisms in the United States is that the ability of a supplier to exercise unilateral market power depends on the level of demands throughout the transmission network, the physical characteristics of the transmission network, and operating constraints on generation units and the transmission network. The number and size of pricing areas does not impact the competition that a supplier faces for selling energy or operating reserves, only where the exercise of unilateral market power shows up. Consequently, mechanisms for promptly detecting market power are desirable features in all wholesale electricity markets.

The experience of US provides two possible frameworks for designing a market power mitigation mechanism—the market structure-based approach and the conduct and impact approach. Although the market structure-based approach relies on a more complex mechanism for determining whether to mitigate a supplier's offer, it has the advantage that it does not require setting many arbitrary thresholds on the supplier's behavior and its impact on market prices before determining whether to mitigate the supplier's offers. Instead it relies on a measure of the ability of a supplier to exercise unilateral market power in making the determination of whether a supplier's offer price should be mitigated. This ability depends on the actual configuration of the transmission network and operating constraints on generation units and transmission network, so it can be adapted to any wholesale market design. For this reason, we favor this approach to local market power mitigation.

A final issue is the legal authority that the market operator has to implement a market power mitigation mechanism. All wholesale markets have terms and conditions that suppliers must respect in order to participate in the market. Therefore, the most straightforward approach to addresses this issue would be to place an agreement by the supplier to be subject to a local market power mitigation mechanism approved by the wholesale market regulator in the terms and conditions for a supplier to participate in the wholesale electricity market. Because all suppliers would be subject to this market power mitigation mechanism an individual supplier could not argue it is being singled out. This requirement in the terms and condition for participating in the market is clearly consistent with the regulatory mandate of all wholesale market regulators to protect consumers from the exercise of unilateral market power.

Table 1: Advantages and Disadvantages of Structural and Conduct-Impact Screens

Type of Test	Advantages	Disadvantages
Structural Test (RSI)	Can be used to identify conditions under which market power concerns are the greatest. Avoids having to set bid-level and price impact thresholds that trigger mitigation, which could lead to mitigation errors.	Does not directly detect whether market power has been exercised. Suppliers may not be able to control the conditions under which mitigation would be implemented. It may fail to mitigate the exercise of market power that may arise when a supplier is not jointly pivotal.
Conduct-Impact Test	Explicitly identifies bid and price-impact thresholds that exceed the stated tolerance levels of policy makers. Suppliers can directly control their bids based on transparent thresholds. Can be implemented in a way to test the price impact of multiples suppliers' bids jointly.	The market monitor must determine the "correct" tolerance threshold for both bid levels and the price impact of the bidding behavior (possible errors). Relies on either an assumed or actual observed cost for each resource. Concerns exist that suppliers can "game the system" by keeping their offer prices just below the mitigation threshold, allowing the exercise of small amount of market power that can add up over the 8,760 hours of the year.

Source: Broehm et al. (2018).

Table 2: Highlights of Surveyed Market Power Mitigation Tools

	CAISO	PJM	ERCOT	NY-ISO	MISO
Type	Structural Approach	Structural Approach	Hybrid	Conduct and Impact Approach	Conduct and Impact Approach
Test	Residual supply index based on counterflow to binding transmission constraints	Three pivotal player test based on relevant supply to relief demand for counterflow to binding transmission constraints	Two-Step Test	Conduct and Impact thresholds based on Constrained and Unconstrained areas	Conduct and Impact thresholds based on Narrow and Broad Constrained areas
Reference Level	Maximum between Default Energy Bid and competitive LMP	Total Production Costs +10%	Mitigated offer cap (MOC) is used as a ceiling on each resource offer price to calculate the final LMPs	Offer-based; LMP-based; Cost-based	Offer-based; LMP-based; Cost-based; Estimated; Averaged
Market Monitoring	Internal: Dept. Of Market Monitoring; Independent: Market Surveillance Committee	Internal: None External: Market Monitoring Unit– Monitoring Analytics	Internal: None; External: Potomac Economics	Internal: Market Monitoring unit; External: Potomac Economics	Internal: None; External: Potomac Economics

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