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June 8, 2020

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *PSEG Fossil LLC; Yards Creek Energy*, LLC, Docket No. EC20-49-000; *Panda Hummel Station LLC; Hummel Generation, LLC*, Docket No. EC20-55-000; *Jersey Central Power & Light Company, Yards Creek Energy, LLC*, Docket No. EC20-65-000 (not consolidated)

Dear Ms. Bose:

On June 1, 2020, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submitted comments including an attached report in the above referenced proceedings. The report contains highly privileged and confidential material (CUI//PRIV), which was redacted from the public version.

The Market Monitor has subsequently discovered that the beginning and end points of the redacted information were not identified with CUI//PRIV flags consistent with the protective order. The attached public and confidential versions make the necessary corrections. Otherwise the content is identical to the filing as submitted on June 1, 2020.

If you have any questions regarding this filing, please contact the undersigned at (610) 271-8053.

Sincerely,

Jeffrey W. Mayes, General Counsel

Attachment

Monitoring Analytics

Market Power Analysis: LS Power Acquisition of Yards Creek and Hummel

The Independent Market Monitor for PJM

June 1, 2020

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Introduction

This report was prepared by PJM's Independent Market Monitor (IMM). The report provides an assessment of the impact of LS Power Development's ("LS Power") proposed purchases of FirstEnergy's and Public Service Enterprise Group Incorporated's ("PSEG") shares of the Yards Creek pumped hydro station and Panda Power Funds' Hummel combined cycle plant on PJM wholesale electricity markets including the energy market, the capacity market and the regulation market. In conducting this analysis for the energy market the IMM used the results from PJM's market structure test for market power mitigation, generator market offer data and generator availability data. The IMM used the PJM data to define the relevant markets and to examine the effects of the proposed acquisitions on those markets using concentration ratios and pivotal supplier indices. The IMM also analyzed the frequency with which the interface constraints that resulted in the prior approved submarkets, AP South, 5004/5005 and PJM East, were binding in recent years.

In the energy market analysis the IMM attributed the entire output of the Yards Creek pumped hydro station and the entire output of the Hummel combined cycle plant to LS Power for postacquisition scenarios. In the Section 203 application for Yards Creek, the applicants included the entire output of Yards Creek and included a 2,000 MW additional acquisition by LS Power as a proxy for a future acquisition not yet filed. On April 23, 2020, LS Power filed a separate Section 203 application for the acquisition of the Hummel plant. Therefore, the IMM performed its analysis jointly for the Yards Creek and Hummel acquisitions, instead of using the generic 2,000 MW acquisition.

Summary

The Commission has previously approved the 5004/5005, AP South, and PJM East submarkets as areas where applicants need to provide competitive analysis screens to evaluate the impact of purchases filed under Section 203 for market power. Submarkets must be evaluated even if the transmission constraints that defined the submarkets do not persist.[1] Current data from the PJM Real-Time Energy Market shows analysis of additional submarkets should be required in PJM. Based on the dynamic nature of the PJM market, ongoing evaluation of relevant submarkets based on changes in PJM congestion patterns should be required.[2]

The IMM provides analysis of the impact of the proposed LS Power asset acquisitions (LS Power acquisitions) on the structure of the PJM markets. The analysis examines

1 138 FERC ¶ 61,109 at P 43 (2012).

2 *See, e.g.,* Monitoring Analytics, LLC., *State of the Market Report for PJM: 2019*, Vol. II, Section 11: Congestion and Marginal Losses at Table 11-29.

market structure metrics in order to quantify the expected impact of the proposed LS Power acquisitions on the market structure of constraint defined markets within PJM. The analysis concludes that the proposed LS Power acquisitions would increase concentration in specific, locational energy markets, would have a significant effect on the market for regulation, and would increase concentration in the RTO capacity market but decrease concentration in MAAC and EMAAC.

The IMM recommends approval of the proposed acquisitions with the condition that LS Power be required to adopt the defined behavioral mitigation measures to address the issues identified in this report. Appropriate mitigation would resolve the identified concerns about competitive impacts in the identified submarkets. The recommended mitigation measures are:

- To address increased local market power in the energy market, the IMM recommends that, for combined cycle and combustion turbine resources, LS Power be prohibited from submitting price-based incremental energy offer curves that include both positive and negative markup relative to the cost-based offer, that LS Power be prohibited from submitting price-based offers with higher economic minimum output MW limits than the cost-based offer, and that LS Power be required to submit cost-based offers for all available fuel types for dual fuel units.
- To address increased local market power in the energy market and an increase in the already significant market share in fast start capable units, the IMM recommends that LS Power be required to submit operating parameters for its fast start units that meet PJM's unit specific parameter limits. LS Power's fast start units postacquisition {BEGIN CUI//PRIV} [redacted] {END CUI//PRIV} and any other units that may become eligible to be fast start resources under PJM's definition in the future.
- To address an increase in local market power in the energy market and an increase in the already significant market share in fast start capable units, the IMM recommends that LS Power be required to follow the day-ahead schedule produced by the PJM hydro optimizer in real-time operations for Seneca and Yards Creek to mitigate the market power of the pumped storage hydro facilities. If the hydro optimizer is not available for either facility, the IMM recommends that LS Power be required to document and adhere to an algorithmic, systematic, and verifiable process for meeting day-ahead must offer requirements through a defined schedule and operating consistent with that schedule and competitively in the real-time energy market.
- To address an increase in the already significant market share in the regulation market, and an increase in pumped hydro assets with their special significance in the regulation market, the IMM recommends that LS Power be prohibited from submitting simultaneous dual offers for the RegA and RegD product in the regulation market. The IMM recommends that if LS Power offers RegD from

pumped hydro resources that LS Power be required to submit only self scheduled offers.

- There are no significant increases in market power in the capacity market. LS Power will continue to have market power in the capacity market and will have the ability to exercise market power under the current definition of the market seller offer cap. The IMM recommends that option of requiring LS Power to make offers in the capacity market at no greater than the net ACR value be considered.

Sufficiency of PJM Market Power Mitigation

In analyzing Section 203 applications and market based rates, applicants may submit competitive screen results using the RTO as the relevant geographic market. The Commission relies on the sufficiency of the market monitoring and mitigation provisions in the RTO's tariff to mitigate local market power within the RTO region.[3] If the market monitoring and market power mitigation provisions in the RTO's tariff are insufficient, detailed analysis of submarkets created by constraints within the RTO is necessary and any market power created or enhanced by the merger or acquisition should require explicit mitigation.[4]

As the PJM markets have evolved, the IMM has identified significant flaws in the market power mitigation provisions of the PJM tariff. Some flaws permit market participants to evade the explicit intent of the PJM market power mitigation rules. Other flaws are gaps in the PJM market power mitigation rules. The IMM's proposed behavioral mitigation conditions in this case address the shortcomings in PJM's market power mitigation process relevant to the LS Power acquisitions.

Energy Market: Local Market Power

Background

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

3 Order No. 697 at P 241.

4 Order No. 697- A at P 111.

The three pivotal supplier (TPS) test is the test for local market power in the energy market. If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based or price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

In the PJM energy market, offer capping occurs in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons. There are identified issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. This is consistent with the day-ahead energy market objective of clearing resources (including physical and virtual resources) to meet the total demand (including physical and virtual demand) at the lowest bid production cost for the system over the 24 hour period. In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer. The cheaper of cost and price based offers is determined using total dispatch cost, where:

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

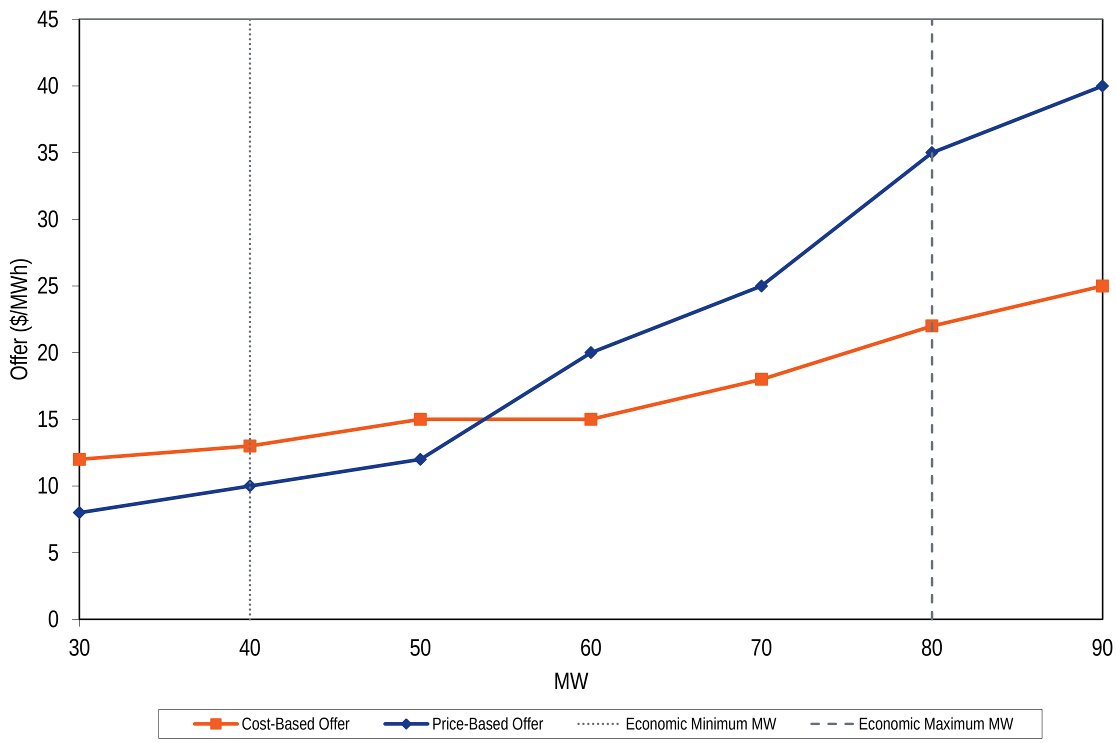
where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

With the ability to submit offer curves with varying markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. The result will be to set prices at a noncompetitive level even after the resource owner fails the TPS test when the unit is marginal or should have been marginal or inframarginal on its competitive offer.

Figure 1 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. Submission of offers in this form permits the unit owner to evade appropriate market power mitigation. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost because it is defined at economic minimum (EcoMin), even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation. The result will be to set prices at a noncompetitive level even after the resource owner fails the TPS test when the unit is marginal or should have been marginal or inframarginal on its competitive offer.

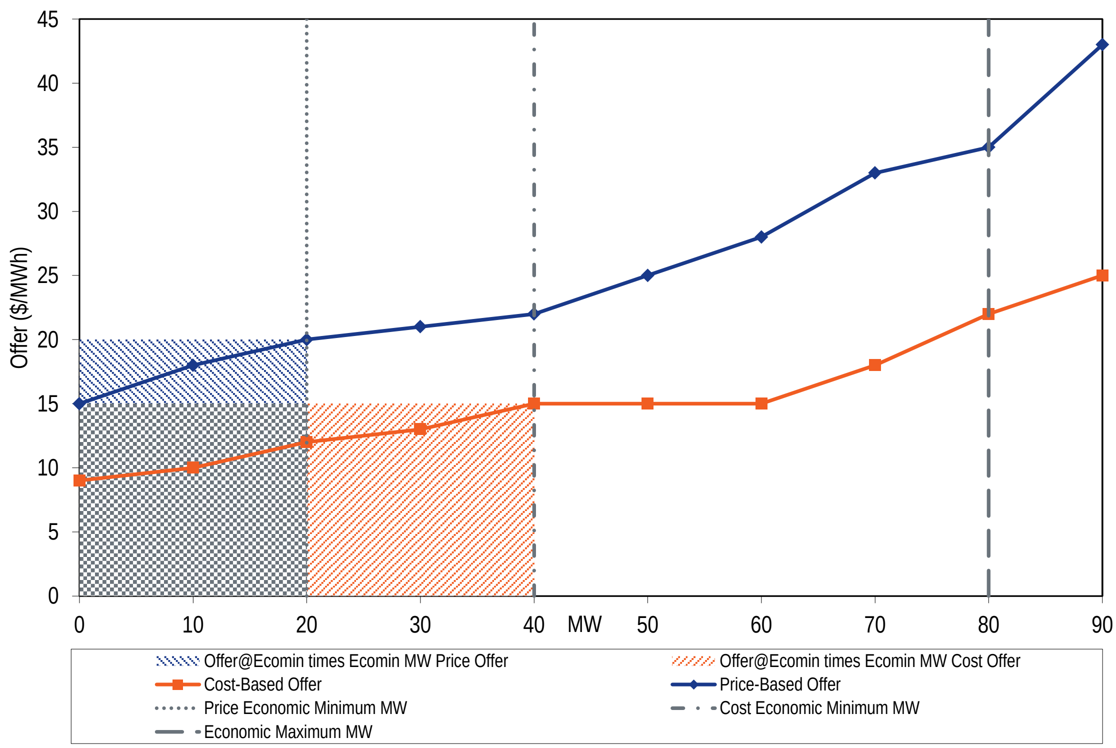
Figure 1 Offers with varying markups at different MW output levels



Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade appropriate market power mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer, resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup.

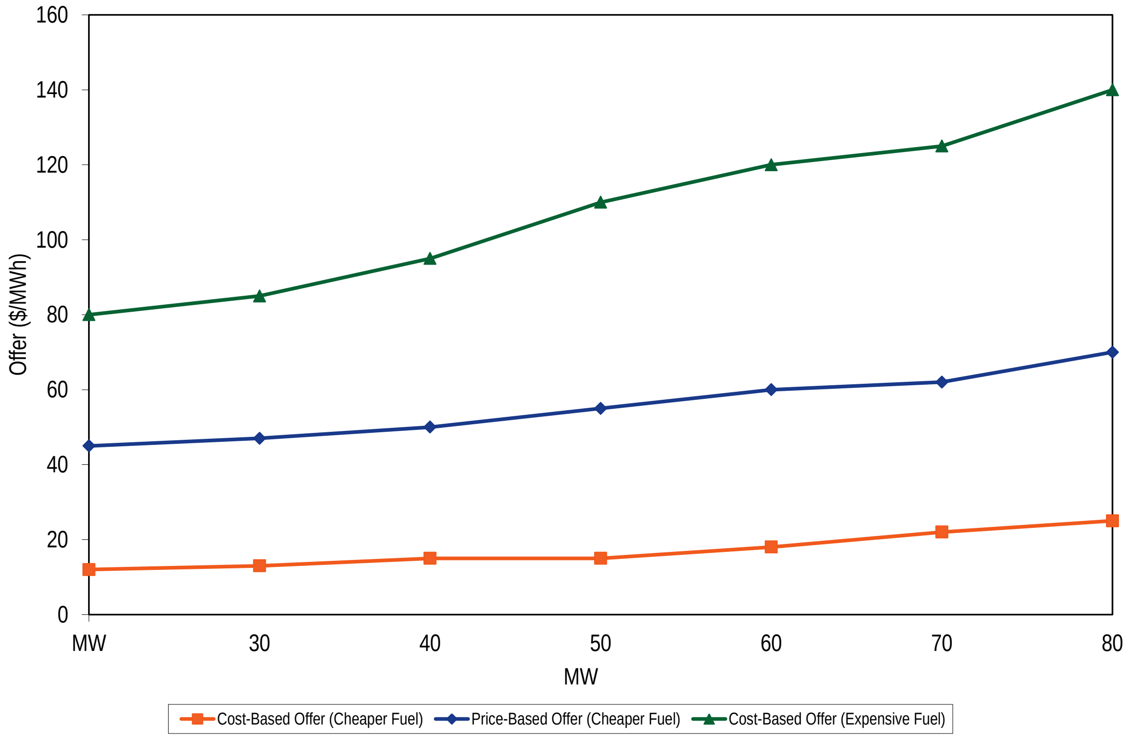
A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 2 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer as a result of the lower economic minimum MW level. However, the price-based offer includes a positive markup and will result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test when the unit is marginal or should have been marginal or inframarginal on its competitive offer.

Figure 2 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup.

Figure 3 Dual fuel unit offers



Applicability to the LS Power Acquisition

The energy market results show that the LS Power acquisitions result in increased local market power for specific submarkets within PJM. Due to the identified limitations of PJM's market power mitigation, increased local market power is not mitigated if LS Power engages in the identified behaviors. Behavioral limits can resolve this issue in an efficient and effective manner. The limits are not onerous, do not limit the ability of LS Power to have high price-based offers, and are fully consistent with competitive behavior.

The IMM recommends that, for combined cycle and combustion turbine resources, LS Power be prohibited from submitting price-based incremental energy offer curves that include both positive and negative markup relative to the cost-based offer, that LS Power be prohibited from submitting price-based offers with higher economic minimum output MW limits than the cost-based offer, and that LS Power be required to submit cost-based offers for all available fuel types for dual fuel units.

Energy Market: Physical Parameter Limitations

Background

The PJM Real-Time Energy Market relies on a subset of generating units to respond to real-time market conditions that were unforeseen by the day-ahead energy market. These fast start units consist of combustion turbines, reciprocating internal combustion engines (RICE), and pumped storage hydro units.[5] PJM's definition of fast start units are units whose time to start is one hour or less and whose minimum run time is one hour or less. Under PJM's fast start pricing market rules, these units will have an increased likelihood of setting prices when they are committed by PJM. The level at which these units will be able to set prices is also substantially higher because fast start pricing incorporates start and no load costs in the fast start units' offers to set price. Concentration in the ownership of fast start resources gives market sellers with high market shares the ability to exercise market power to set prices at greater than competitive levels.

All PJM generating units submit physical operating parameters as part of their energy market offer schedules. For example, generating units specify start times, notification times, minimum run times, maximum output MW limits, minimum output MW limits, and ramp rates in MW per minute. The physical operating limits determine how flexibly PJM may schedule the unit for operation. Generators with market power have the ability to use physical operating parameters to exercise market power in two ways: by operating uneconomically to create uplift payments; and by withholding uneconomically to raise prices.

PJM implemented operating parameter mitigation in 2008 to prevent these anticompetitive behaviors. All cost-based offers in PJM must meet specified limits on operating parameters. The IMM has identified a number of problems with PJM's operating parameter mitigation.[6] In particular, units can avoid parameter mitigation by discounting their price-based offer relative to their cost-based offer at the economic minimum output limit. (See Figure 1) The discounted price-based offer ensures that PJM will choose to operate the unit on the offer with less flexible parameters.

Applicability to LS Power Acquisition

The energy market results demonstrate LS Power's increasingly large share in the market for fast start resources along with enhanced local market power. Due to the

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5 Batteries are also capable of fast start, but they currently participate only in the regulation market and are not committed by PJM in the energy market.

6 *See* the *2020 Quarterly State of the Market Report for PJM: January through March*, Section 3, "Energy Market" at 132–133.

identified limitations of PJM's physical parameter mitigation, parameters are not mitigated for units with local market power or during emergency conditions if LS Power engages in the identified behaviors. Behavioral limits can resolve this issue in an efficient and effective manner. The limits are not onerous and are fully consistent with competitive behavior.

The IMM recommends that LS Power be required to submit operating parameters for its fast start units that meet PJM's unit specific parameter limits. LS Power's fast start units postacquisition {BEGIN CUI//PRIV} [redacted] {END CUI//PRIV} and any other units that may become eligible to be fast start resources under PJM's definition in the future.

Pumped Hydro

Background

Pumped storage hydro units are among the largest and most flexible resources in the PJM energy market. Their rapid ramping capability means that they are both fast start units and participants in the regulation market. Pumped storage hydro units have limited energy for dispatch within an operating day and the marginal cost of that energy is a function of the cost of pumping the water up to the pond and the intraday opportunity cost. The intraday opportunity cost is not calculated by the PJM Real-Time Energy Market. It is evaluated only in the day-ahead energy market process.

As described in Section 1.11.3(a) of Schedule 1 to the PJM Operating Agreement, energy limited units, particularly pumped storage hydro units, are not economically dispatched by PJM in the real-time energy market. As a result, pumped storage hydro units are not offer capped or otherwise mitigated when their owners fail the Three Pivotal Supplier test. This means that pumped storage hydro units have the ability to strategically withhold economic energy or to produce excess, uneconomic energy. Both could result in the exercise of market power by increasing or decreasing market prices compared to the competitive level. Given the large amount of energy pumped storage hydro units are capable of producing in a short amount of time, these units can have a large influence on real-time energy market prices. The PJM Open Access Transmission Tariff (OATT) and Operating Agreement do not provide any limits on behavior in the real-time energy market to mitigate the market power of pumped storage hydro units.

Applicability to the LS Power Acquisitions

As a result of this acquisition, LS Power will have a large share of all pumped storage hydro capacity in PJM. Prior to the acquisitions, LS Power owned 23.7 percent of the Bath County facility, and the entire Seneca facility. With the Yards Creek acquisition, LS Power's market share of pumped storage capacity in PJM increases from 21.5 percent to 29.0 percent, in an already highly concentrated segment of the PJM market. Table 1 shows LS Power's market share and HHI in the pumped storage hydro market segment before and after the Yards Creek acquisition.

Table 1 Impact of LS Power acquisition on pumped storage hydro capacity in PJM

	Preacquisition	Postacquisition
Pump storage hydro ICAP owned by LS Power	1,197	1,617
Total pumped storage hydro ICAP in PJM	5,574	5,574
Market share	21.5%	29.0%
HHI	2170	2456

PJM provides a hydro optimizer to produce an economic day-ahead schedule for pumped storage hydro units. PJM does not provide an economic schedule for pumped storage hydro units in the real-time energy market. Following the day-ahead schedule produced by the hydro optimizer in real-time operations mitigates the market power of the pumped storage hydro units by creating predetermined limits on the operation of the units and disallowing withholding or overproduction that may increase or decrease prices from the competitive level.

The IMM recommends that LS Power be required to follow the day-ahead schedule produced by the PJM hydro optimizer in real-time operations for Seneca and Yards Creek to mitigate the market power of the pumped storage hydro facilities. If the hydro optimizer is not available for either facility, the IMM recommends that LS Power be required to document and adhere to an algorithmic, systematic, and verifiable process for meeting day-ahead must offer requirements through a defined schedule and operating consistent with that schedule and competitively in the real-time energy market.

Regulation Market

Background

The PJM regulation market design is flawed. The market design flaws and market participant behavior result in inefficient market outcomes, including extreme price spikes. Because pumped storage hydro units have both a fast response time and the ability to provider a large amount of regulation, they qualify to dual offer both RegA (slow regulation) and RegD (fast regulation) products in the PJM Regulation Market.

Regulation Dual Offers

Under PJM market rules, regulation units that have the capability to provide both RegA and RegD MW are permitted to submit an offer for both signal types in the same market hour. While the objective of the PJM market design is to find the least cost combination of RegA and RegD resources to provide the required level of regulation service, the method of clearing the regulation market for an hour in which one or more units has a dual offer leads to solutions that are not the most economic.[7]

In order for the clearing engine to provide the correct economic solution when the pool of available resources contains one or more units with dual offers, the calculation would have to be performed iteratively to determine which of the dual offers would provide the least cost solution. This is not, however, how PJM clears the regulation market when there are dual offer units. Instead, PJM rank orders the regulation supply curve by potential effective cost assuming the dual offer resources are available as both RegA and RegD resources simultaneously. When the clearing engine rank orders each available resource based on their potential effective cost, every RegD resource, including dual offer resources, is assigned a unit specific benefit factor.

After rank ordering the resources, each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. While this recognizes that the dual offer resource cannot supply both RegA MW and RegD MW at the same time, PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

During the clearing phase, the MBF of RegD resources is a function of the RegD MW that clear. The MBF for all RegD resources declines as more RegD resources are cleared. Based on this relationship, in the case where a dual offer unit is assigned to be a RegA resource rather than a RegD resource, the MBF of remaining RegD resources in the supply curve should increase. But PJM does not recalculate the MBF values for the remaining RegD resources. The result is that the MBF in the clearing engine is incorrectly low relative to what the MBF would be due to the amount of RegD that actually clears the market. As a result, the market does not clear the optimal amount of RegD and the market clears more effective MW than required.

Regulation Price Spikes

Beginning in 2018, extreme price spikes occurred in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of

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[7] See *2020 Q1 State of the Market Report for PJM*, Section 10: Ancillary Services; pg 499-501.

their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all-in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit is very low (less than one), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) of that resource in the clearing of the market engine, and the realized offer price of the resource, after it is cleared, in the actual market result. The result is a significant and unexpected price spike in the regulation market.

{BEGIN CUI//PRIV} [redacted] {END CUI//PRIV}

Applicability to LS Power Acquisition

Given LS Power's current market share in the PJM Regulation Market and the large share of pumped storage hydro capacity, the PJM regulation market issues are relevant to the evaluation of the LS Power acquisitions. LS Power currently has the ability to participate in the regulation market as both RegA and RegD with Seneca, and has the potential to do so with Yards Creek and Hummel. Pumped storage hydro units are capable of offering as both RegA and RegD. {BEGIN CUI//PRIV} [redacted] {END CUI//PRIV}

The IMM recommends as a condition of any approval of the purchases that LS Power be prohibited from submitting simultaneous dual offers for the RegA and RegD products in the regulation market. The IMM recommends that if LS Power offers RegD from pumped hydro resources that LS Power be required to submit only self scheduled offers.

Methods of Analysis

In analyzing whether a proposed merger is consistent with the public interest, the FERC considers the "effect of the transaction on competition, rates, and regulation of the applicant by the Commission and state commissions with jurisdiction over any party to the transaction."[9] In this report, the IMM focuses on the first factor, the effect on competition, measured by the impact on the structure of relevant markets based on actual market data. The IMM evaluates the impact of the merger using concentration

8 *See 2020 Q1 State of the Market Report for PJM*, Section 10: Ancillary Services at 501–503.

9 18 CFR § 33.2(g) (2011).

thresholds, including those defined in FERC's Competitive Analysis Screen, and pivotal supplier analysis.[10]

Any analysis of market structure depends on an accurate definition of the relevant markets. Market definitions depend on properly identifying and evaluating potential substitutes for a given product. Within organized markets data are available, and should be used, to define markets based on how the units are evaluated and dispatched to meet demand, based on networked relationships between resources and load, relative costs, availability and operational parameters. Such an approach provides definitions of the relevant markets based on actual operational data related to the participants and the markets in which they operate.

In the IMM analysis, the definition of the relevant market is based on the actual substitutability among available, relevant resources which in turn is based on the physical facts of the system and how the PJM markets defined the substitutability among available resources in the relevant markets over the analysis period. Rather than limit its analysis to a predefined range of load and price levels, the IMM has analyzed every actual relevant market defined by a constraint in the real-time look ahead tool used by PJM to identify structural market power, known as Intermediate Term Security Constrained Economic Dispatch (IT SCED). The relevant PJM submarkets defined in this analysis are those local energy markets created by transmission constraints within the broader PJM market that occurred for one hundred or more hours in 2019 and where the units to be acquired provided relief MW in 50 or more hours. The relevant ancillary services markets are those defined by the actual operation of PJM markets in 2019. The relevant capacity markets are those that resulted from the actual operation of the markets for the 2020/2021 and 2021/2022 delivery years.

The IMM analysis of the relevant markets reflects the information available based on the actual operation of the PJM wholesale power markets, rather than approximations of seasonal geographic markets that ignore local transmission constraints, distribution factors and relative dispatch costs. The information used to prepare the analysis

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[10] 18 CFR § 33.3; *see also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000) ("Order No. 642"); *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005) ("Order No. 669"), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 ("Order No. 669-A"), *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶31,225 (2006) ("Order No. 669-B"); *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 77 FERC ¶61,263 (*mimeo*), FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶61,321 (1997) ("Merger Policy Statement"); *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007).

included in this report is highly confidential and market sensitive as it relates to specific market participants.[11]

Merger Standards

For the evaluation of the impact of a merger on competition, FERC adopted the 1992 Horizontal Merger Guidelines ("1992 Guidelines") as the analytical framework for analyzing the impact of mergers on competition as described in the Competitive Analysis Screen relied on by the Commission.[12]

The Commission reserves the opportunity to consider alternative approaches for analyzing the impact of proposed mergers, including analyses similar to the analysis included in this report, when evaluating proposed mergers in PJM.[13]

The 1992 Guidelines outlined the enforcement policy of the Department of Justice and the Federal Trade Commission concerning horizontal mergers subject to section 7 of the Clayton Act, section 1 of the Sherman Act, and Section 5 of the Federal Trade Commission Act. As noted in the 1992 Guidelines, "[t]he unifying theme of the Guidelines is that mergers should not be permitted to create or enhance market power or facilitate its exercise."[14]

FERC's Competitive Analysis Screen, based on the 1992 Guidelines, uses market concentration, measured by the HHI, as a basic metric of the structural competitiveness of a market. The 1992 Guidelines define three basic levels of market concentration while recognizing that "[o]ther things being equal, cases falling just above and just below a

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11 *See* OATT Attachment M–Appendix § I.

12 *See* Order No. 642 *mimeo* at 4–5; U.S. Dept. of Justice & Federal Trade Commission, "Horizontal Merger Guidelines" (1992), as revised (1997). DOJ and FTC modified their guidelines in 2010, increasing their HHI and market share thresholds and expanding the criteria used to define the relevant market. U.S. Dept. of Justice & Federal Trade Commission, "Horizontal Merger Guidelines" (August 19, 2010). FERC considered whether to revise it policies to follow the DOJ and FTC 2010 modifications, but decided, after notice and inquiry, to retain the 1992 Guidelines. *Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶61,109 (2012) ("Order Reaffirming the 1992 Guidelines").

13 *See Id*. at P 38 ("We reiterate, however, that the Commission may consider arguments that a proposed transaction raises competitive concerns that have not been captured by the Competitive Analysis Screen. Likewise, while applicants must continue to provide a Competitive Analysis Screen, we will also consider any alternative methods or factors, if adequately supported."); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012).

14 1992 Guidelines at 2.

threshold present comparable competitive issues."[15] A market with an HHI of less than 1000 is considered to be unconcentrated. Mergers resulting in HHI level less than a 1000 are not considered to have adverse competitive effects. A market with an HHI between 1000 and 1800 is considered to be moderately concentrated. A merger in or resulting in a moderately concentrated market is not considered to have an adverse effect on competition if it increases the market's HHI by less than 100 points. A merger in or resulting in a moderately concentrated market is considered to "potentially raise significant competitive concerns" if it increases the market's HHI by 100 points or more.[16] A market with an HHI of 1800 or above is considered to be highly concentrated. A merger in or resulting in a highly concentrated market is not considered to have an adverse effect on competition if it increases the market's HHI by less than 50 points. A merger producing an increase in the market HHI of 50 points or more in a highly concentrated market "potentially raises significant competitive concerns."[17]

The Commission approach requires analysis at a range of load and price levels given the effect of the combination of load levels and seasons on the competitive price. The IMM has alternatively performed its energy market analysis on the basis of actual market data that evaluates local market power in the PJM Real-Time Energy Market during the period from January 1, 2019 through December 31, 2019 period. The IMM has performed its capacity market analysis on the basis of the modeled and constrained LDAs in the 2020/2021 and 2021/2022 RPM Base Residual Auctions. The IMM has performed its ancillary services market analysis on the basis of the actual hourly cleared markets in January 1, 2013 through June, 30, 2014 period.

Market Based Rate Authority Metrics

The FERC's Market-Based Rates Order, Order No. 697, defines the market structure characteristics that must be met for a market participant to be granted market based rates for three years.[18] Order No. 697 indicates that an individual seller market share in excess of 20 percent is an indicator of market power and that an HHI of 2500 is an indicator of market power.[19] Order No. 697 also uses the residual supplier index (RSI), a pivotal supplier metric, to define market structure.[20]

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15 1992 Guidelines at 15.

16 *Id*. at 16.

17 *Id.*

18 *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Order No. 697, 119 FERC ¶ 61,295 (2007) ("Order No. 697").

19 Order No. 697 at P 111.

20 Order No. 697 at PP 106–109.

The Commission adopted market power screens and tests in the Order No. 697.[21] The Order No. 697 defined two indicative screens and the more dispositive delivered price test ("Delivered Price Test or DPT"). The Delivered Price Test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and, using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if, in the relevant market, the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) exceeds 2500. Order No. 697 recognized that there are interactions among the results of each screen under the Delivered Price Test and that some interpretation is required and, in fact, is encouraged.[22]

In a market with an inelastic demand curve, the existence of two jointly pivotal suppliers, regardless of the amount of excess capacity available, does not provide a market structure that will result in a competitive outcome. The 20 percent market share and the HHI screen are also weak screens for structural market power on a stand-alone basis. A market share in excess of 20 percent does not demonstrate market power if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not demonstrate the absence of market power if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. An HHI in excess of 2500 does not demonstrate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not demonstrate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[23]

Higher concentration ratios indicate that comparatively small numbers of sellers dominate a market while lower concentration ratios mean larger numbers of sellers split market sales more equally. Lower aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. Higher concentration ratios do, however, indicate an increased potential for participants to exercise market power. Despite their significant limitations, concentration ratios provide useful information on market structure.

Notwithstanding the HHI level, a supplier may have the ability to raise market prices. If reliably meeting demand requires a single supplier, that supplier is pivotal and has monopoly power. If a small number of suppliers are jointly required to meet demand,

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21 *Id*.

22 *Id*.

23 For detailed examples, see Joseph E. Bowring, PJM market monitor. "IMM Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

The residual supply index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market. A single generation owner is pivotal if the output of the owner's generation facilities is needed to meet demand. Multiple generation owners are jointly pivotal when the output of the owners' generation facilities, taken together, is needed to meet demand. When a generation owner is pivotal, it has the ability to affect market price. For a given level of market demand, the RSI compares the market supply, net of the supply controlled by one or more generation owners, to the market demand. The RSI value is calculated as a ratio, where total supply minus the supply of the tested suppliers is divided by the market demand. If the RSI is greater than 1.00, the supply of the specific generation owner(s) is not needed to meet market demand and that generation owner(s) has a reduced ability to influence market price. If the RSI is less than 1.00, the supply owned by the specific generation owner(s) is needed to meet market demand and the generation owner(s) is a pivotal supplier with an ability to influence price. When the RSI is reported for a market, the reported RSI is for the largest supplier or identified number of the largest suppliers. As with concentration ratios, the RSI is not a bright line test.

FERC indicates that a single supplier RSI of less than 1.0 is an indicator of market power.[24] In the PJM markets a three pivotal supplier RSI of less than 1.0 defines the existence of local market power. The three pivotal supplier test (TPS) defines market power even in the presence of market share and concentration levels that fall below 1992 Guidelines for a competitive market structure.[25]

Three Pivotal Supplier Test

In the IMM analysis, the basic metrics used for each market include market share, the Herfindahl-Hirschman Index (HHI) and the three pivotal supplier test (TPS), a residual supplier index used in the PJM markets to define locational market power. Market share measures the proportion of market output contributed by a supplier. Market share is calculated by dividing the output of a supplier by total cleared supply in a market. Concentration ratios are a summary measure of market share. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market.

The IMM uses the three pivotal supplier test as the key measure of market structure and structural market power. The three pivotal supplier test is used in PJM markets to define

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24 *See Midwest Independent Transmission System Operator, Inc.*, 121 FERC ¶ 61,190 at P 6 n.5 (2007).

25 AEP Order at P 111.

the existence of local market power and as a trigger for market power mitigation. A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate.

The three pivotal supplier test, as implemented in PJM markets, is consistent with the Commission's market power tests, encompassed under the Delivered Price Test. The three pivotal supplier test is an application of the Delivered Price Test to the real-time energy market, the day-ahead energy market, the regulation market and the Reliability Pricing Model (RPM) capacity market. The three pivotal supplier test is also consistent with the Delivered Price Test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action which accounts for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent of supply does not indicate market power if the holder of that market share is not jointly pivotal to meet demand, and is unlikely to be able to affect the market price. A market share less than 20 percent of supply does not indicate the absence of market power if the holder of that market share is jointly pivotal to meet demand and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not indicate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not indicate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[26]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is a

[26] For detailed examples, see Joseph E. Bowring, PJM Market Monitor, "IMM Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, "In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives."[27] The Commission also stated:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response. [28]

The three pivotal supplier test is a reasonable application of the Delivered Price Test to the case of local markets that are defined by actual conditions in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal, and it provides a clear test for whether excess supply is adequate to result in an adequately competitive market structure.

TPS Test: Defining the Relevant Market

The goal of defining the relevant market is to include those producers that actually compete to determine the market price or could actually compete to determine the market price. Conversely, the goal of defining the relevant market is to exclude those units that are not meaningful competitors and therefore do not have an impact on the clearing price. The existence of market power within that defined market depends on the ability of the firm to raise price while continuing to sell its output. A firm cannot successfully increase the market price above the competitive level if competitors would replace its output when it did so.

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27 AEP Order at P 72.

28 *Id*. at P 103.

The Commission definition of the relevant market includes all suppliers which have costs less than or equal to 1.05 times the clearing price. The Commission definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier test incorporates a definition of meaningful competitors that is at the extremely high end of inclusive. It is questionable whether a unit with a competitive offer price of $300 offer meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

The three pivotal supplier test is designed to test the relevant market. For example, in the case of the market for out of merit generation needed to relieve a constraint in real time, the three pivotal supplier test examines the market specifically available to provide that relief. Under these conditions, the three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint, as defined by PJM's market solution software. The market demand consists of the incremental, effective MW required to relieve the constraint.[29] The market demand is calculated as the difference between the defined MW limit on flow across the constraint and the flow in an economic dispatch solution if the limit did not exist (unconstrained flow). The market supply consists of the incremental, effective MW of supply available to relieve the constraint. This includes resources that can ramp up or start up to provide relief for the constraint as well as resources that can ramp down to provide relief for the constraint. The sign of the distribution factor (dfax) of a resource with respect to the defined constraint indicates whether a resource would relieve the constraint by increasing or decreasing the output. A resource with positive

[29] A unit's contribution toward effective, incrementally available supply is based on the dfax of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, if the capacity in question is available within the period that the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a dfax of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a dfax of 0.5 to the constraint would be 25 MW.

dfax with respect to a constraint provides relief by reducing the output, and a resources with a negative dfax with respect to the same constraint provides relief by increasing its output. For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

Unlike structural tests that define markets by geographic proximity, TPS makes explicit and direct use of the incremental, effective MW of supply available to relieve the constraint at a distribution factor greater than, or equal to, the dfax used by PJM in operations. Only the supply that is part of the market as defined by the reality of the electric network as measured by unit characteristics and distribution factors is included in the three pivotal supplier test, to the extent that it is incremental, effective MW of supply that is available at a price less than, or equal to, 1.5 times the clearing price (Pc) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint.

Constraints: Defining the Relevant Market

In its Order Reaffirming the 1992 Guidelines (at P 43), the Commission stated:

> The Commission will remain flexible in its approach and will reevaluate whether a previously recognized submarket continues to exist if the evidence shows that the persistent transmission constraints that led to the recognition of that submarket are no longer present. We clarify that we will not require applicants to submit a DPT for an identified submarket if the applicants do not have overlapping generation within the submarket and lack firm transmission rights to import capacity into that market.

The PJM submarkets used to perform the Delivered Price Test do not represent currently prevailing patterns of congestion in the PJM market. Congestion patterns are dynamic and change with the relative costs of generation by fuel type and technology and by new entry and by retirements. The prevailing flow of energy in 2018 and 2019 was from north to south, not the west to east as was the case for much of PJM's history. In 2019, the constraints in the area of the Pennsylvania/Maryland border, Conastone – Peach Bottom, Conastone, Graceton – Safe Harbor, and Bagley – Graceton, defined the most significant limiting elements on the economic flow of energy in PJM. These binding constraints occurred throughout the year, and especially at competitively significant times during the summer peak hours of 2019 and on October 1-2, 2019. The submarkets defined by the AP South, 5004/5005, and PJM East interfaces existed infrequently in 2019 because the identified constraints did not bind. These submarkets were relevant in prior years and prior analyses, but have not been meaningful submarkets under recent market conditions.[30] Table 2 includes the constraint hours for the submarkets identified by the IMM using the TPS test results and those used for the Delivered Price Test.

The broader point about congestion is that it is dynamic and unpredictable. Submarkets in one period may not be in subsequent periods. The analysis of market power and of mergers should reflect these basic facts. Local market power may not exist in one period and may exist in the next. Local market power may exist in one period and not in the next. It is essential that merger reviews recognize that increased concentration of ownership creates the potential for market power beyond the specific facts of a specific period. It is essential for that reason to have clear, workable and enforceable rules for market power mitigation that can address the dynamic reality of PJM markets. Given the identified weaknesses in the current PJM market power mitigation rules, the IMM has proposed specific behavioral mitigation rules that the Commission should impose on LS Power as a condition of accepting this merger. The risks of not imposing these rules are high as those risks are the risks that market power could be exercised under the existing rules. The risks of imposing the rules are low or nonexistent as the proposed behavioral remedies simply require competitive behavior.

Energy Market Results

Energy market results include the pivotal supplier analysis for constraint defined submarkets within PJM and PJM market concentration results for fast start units for 2019.

The results show that the LS Power acquisitions increase the frequency with which LS Power fails the TPS test. The submarkets of greatest concern are the Conastone – Peach Bottom submarket and the PA Central submarket, due to the acquisition of Hummel. In both submarkets, LS Power's TPS score falls. For the Conastone – Peach Bottom, average HHI also increases. For PA Central, TPS scores decrease significantly. While average HHIs fall, HHIs increase in a number of hours. The results illustrate the significance of the pivotal supplier analysis and the limitations of the HHI analysis.

With the acquisition of Yards Creek, LS Power's market share for fast start units increases from 19.3 to 23.5 percent.

Defining Submarkets

The analysis of the impact of the merger on the energy market focuses on constraint defined locational markets (submarkets) that occurred in 2019 in the PJM real-time energy market. PJM's three pivotal supplier test evaluates structural market power and triggers market power mitigation based on such constraint defined locational markets in the energy market. The relevant markets are defined based on the incremental, effective

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30 *See PPL Corporation, RJS Holdings LLC*, 149 FERC ¶ 61,260 at P 97 (2014).

MW of relief supply available to relieve each market defining constraint based on the actual results of the TPS test. This definition of the market allows the identification of resource owners in a position to exercise market power by directly affecting locational prices when a transmission constraint binds.

A constraint is included in the analysis only if at least one of the units involved in the transaction had incremental effective MW of supply for the constraint in 50 or more hours and the constraint bound for 100 or more hours in the real-time energy market in 2019, and where the change in average HHI post LS Power Acquisition is not zero.[31] The identified constraints define the submarkets in the analysis. The constraints are ranked by total congestion costs in 2019 in the results tables.

The TPS analysis identifies nine constraints or submarkets which meet the criteria in 2019 (Table 2).[32] Table 2 also includes the constraint hours for the submarkets used for the Delivered Price Test. Market hours are defined based on IT SCED target times in TPS test cases. If a specific facility is constrained in one of the four target times in the IT SCED solution case, it is counted as one market hour.

Table 2 TPS Identified submarkets and DPT submarkets: 2019

Facility	Real-Time Constraint Hours	Market Hours	Change in HHI
Conastone - Peach Bottom	2,947	4,043	7
Conastone	227	272	8
Graceton - Safe Harbor	561	754	7
Wescosville	112	120	73
Siegfried	432	524	(208)
Bagley - Graceton	126	169	(14)
Nottingham	468	568	23
PA Central	644	651	(374)
Keystone	166	201	13
AP South	27	115	3
PJM East	15	21	92
5004/5005	0	0	0

The supply for constraint relief is defined the same way it is calculated in the three pivotal supplier (TPS) test implemented in PJM's Real-Time Energy Market. The TPS test

31 If the change of HHI is greater than -0.5 and less than 0.5, it is rounded to zero.

32 When a specific facility is constrained for one or more five minute intervals within an hour in the LPC solution case, it is counted as one real-time constraint hour. *See* the *2019 State of the Market Report for PJM*, Volume II, Section 11, "Congestion and Marginal Losses."

for the real-time energy market is currently evaluated in the Intermediate Term Security Constrained Economic Dispatch (IT SCED) tool that solves the energy market for four different look ahead times. Each of these look ahead times is called a target time. When ITSCED identifies a binding constraint for one or more target times, the supply defined for each target time consists of the sum of incremental, effective MW of relief from all available online units and offline units capable of starting consistent with the target time compared to an unconstrained solution. Each unit's supply is calculated as the difference between its unconstrained dispatch MW and the constrained dispatch MW adjusted by the unit's dfax for that particular constraint. The constrained dispatch MW of a unit consists of ramp limited MW that are available at a price less than or equal to the sum of the system marginal price (SMP) and 1.5 times the congestion component attributed to that constraint (1.5 times constraint shadow price times unit dfax). The resulting measure of effective relief is termed the relevant effective supply in the market for the relief of the defined constraint. Results are provided for peak hours, off peak hours and all hour periods.

Summary Results for Specific Constraints

For the defined submarkets, the TPS score, market concentration and HHI levels are calculated on a pre and a post LS Power acquisition basis for each target time. There can be multiple target times in an hour and there can be hours with no target times. Market hours are defined based on IT SCED target times using the time at the beginning of the hour. For example, for target times at 10:00, 10:15, 10:30 and 10:45, the market results are averaged as hour beginning 10:00.

Pivotal Supplier Analysis

Table 3 and Table 5 show, for 2019, by constraint, the number of market hours that one or more market participants failed (failed market hours) the three pivotal supplier test and the number of market hours LS Power failed the TPS test (pre and postacquisition) for at least one IT SCED target time in that hour. Table 4 and Table 6 show pre and post LS Power average TPS scores.[33] Table 3 and Table 4 provide the results for peak hours for the pre and post LS Power acquisition.

Table 5 and Table 6 provide the results for off peak hours for the pre and post LS Power acquisition.

33 The TPS score is the residual supply index (RSI) for three suppliers together. RSI is the ratio of the residual supply to the demand for a product. In the TPS score, residual supply is the total supply for constraint relief available minus the supply from three suppliers (the two largest suppliers and the supplier being evaluated). The demand is the incremental relief needed for each constraint, calculated as the difference between the unconstrained flow and the limit on the constraint.

A TPS score of less than 1.0 indicates that the supplier being tested failed the market power test and is subject to mitigation under the PJM market rules. A reduction in the TPS score as a result of the acquisition indicates that the acquisition has made LS Power more important, more pivotal, in meeting the demand in the defined market. The absence of a change in the number of hours in which LS Power is pivotal is not an indicator that the acquisition does not have an anticompetitive effect on the tested market. For example, if LS Power had a TPS score of less than 1.0 in a market hour prior to the acquisition (indicating a TPS failure for the hour) and a lower TPS score postacquisition, this would indicate that the acquisition increased the market power of LS Power. But there would be no change in the number of market hours that LS Power failed the TPS test because the same hour is failed pre and postacquisition.

The analysis of peak and off peak hours shows that the LS Power acquisition causes the number of market hours in which LS Power failed TPS tests to increase in all the selected markets. Table 3 and

Table 5 show that LS Power failed market hours significantly increase in the Siegfried, PA Central and Wescosville markets during peak and off peak hours. Summing the results for the related Conastone - Peach Bottom, Conastone, and Graceton – Safe Harbor constraints also shows a significant increase in failed market hours.

In these markets the TPS scores fell as a result of the purchases. Table 4 shows that post LS Power acquisition, the average TPS score decreased for LS Power for seven of the selected constraints. The average score for LS Power decreased significantly for PA Central constraint from 1.79 pre LS Power Acquisition to 0.50 post acquisition. Table 6 shows that post LS Power acquisition, the average score decreased for LS Power for six of the selected constraints. TPS scores decrease most for PA Central, Graceton – Safe Harbor, and Conastone – Peach Bottom.

Table 3 Proposed LS Power Acquisition. Changes in TPS Tests Failed: Peak Market Hours: 2019

	TPS Tests Failed: Peak Market Hours					
	Pre		Post		Change	
Facility	All Companies	LS Power	All Companies	LS Power	All Companies	LS Power
Conastone - Peach Bottom	2,095	1,871	2,091	1,930	(4)	59
Conastone	160	128	160	129	0	1
Graceton - Safe Harbor	264	200	264	225	0	25
Wescosville	142	0	142	82	0	82
Siegfried	338	0	338	254	0	254
Bagley - Graceton	137	86	137	90	0	4
Nottingham	363	326	363	335	0	9
PA Central	359	16	354	265	(5)	249
Keystone	105	97	105	98	0	1

Table 4 Proposed LS Power Acquisition. Changes in Average TPS Scores: Peak Hours: 2019

	LS Power Average TPS Score		
Facility	Pre	Post	Change
Conastone - Peach Bottom	1.42	1.37	(0.05)
Conastone	1.20	1.19	(0.01)
Graceton - Safe Harbor	0.53	0.44	(0.09)
Wescosville	0.00	0.03	0.03
Siegfried	0.00	0.10	0.10
Bagley - Graceton	0.82	0.79	(0.03)
Nottingham	1.01	0.97	(0.04)
PA Central	1.79	0.50	(1.29)
Keystone	0.88	0.84	(0.04)

Table 5 Proposed LS Power acquisition. Changes in TPS Tests Failed: Off Peak Market Hours: 2019

	TPS Tests Failed: Off Peak Market Hours					
	Pre		Post		Change	
Facility	All Companies	LS Power	All Companies	LS Power	All Companies	LS Power
Conastone - Peach Bottom	1,860	1,658	1,862	1,701	2	43
Conastone	87	71	88	73	1	2
Graceton - Safe Harbor	550	492	550	503	0	11
Wescosville	51	0	51	38	0	38
Siegfried	278	0	278	206	0	206
Bagley - Graceton	78	44	78	44	0	0
Nottingham	236	215	236	218	0	3
PA Central	349	7	346	262	(3)	255
Keystone	104	70	104	73	0	3

Table 6 Proposed LS Power acquisition. Changes in Average TPS Scores: Off Peak Hours: 2019

	LS Power Average TPS Score		
Facility	Pre	Post	Change
Conastone - Peach Bottom	1.32	1.28	(0.05)
Conastone	1.97	1.91	(0.05)
Graceton - Safe Harbor	0.67	0.62	(0.05)
Wescosville	0.00	0.02	0.02
Siegfried	0.00	0.14	0.14
Bagley - Graceton	0.55	0.54	(0.01)
Nottingham	0.66	0.67	0.01
PA Central	0.72	0.51	(0.21)
Keystone	0.93	0.90	(0.03)

Summary HHI Analysis

Table 7, Table 8 and Table 9 show the minimum, average, maximum and median pre and post LS Power acquisition HHIs for each constraint for which the units involved in the transaction provided relief supply in 2019. Table 7 provides the results for peak hours, Table 8 provides the results for off-peak hours and Table 9 provides the results for all hours.

Analysis of the results indicates that, prior to the LS Power acquisitions, eight of the relevant submarkets are highly concentrated. Table 7 shows that preacquisition mean

HHIs ranged from 1484 (Conastone) to 7649 (PA Central), for peak hours. Preacquisition median HHIs ranged from 1363 (Conastone) to 7763 (PA Central), over peak hours. Postacquisition, for peak hours, the mean HHI increased for five of the nine constraints and decreased for three constraints. The mean HHI decreased 194 for Siegfried and 458 for PA Central.

Table 7 Proposed LS Power Acquisition peak hours pre and postacquisition HHIs by constraint: 2019

		Pre HHI			Post HHI			Change in HHI		
Facility	Market Hours	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
Conastone - Peach Bottom	2155	917	1775	7544	861	1787	7544	(56)	12	0
Conastone	170	894	1484	4646	895	1488	4646	0	4	0
Graceton - Safe Harbor	233	1110	3016	7710	1140	3026	7710	31	10	0
Wescosville	82	3179	5272	8401	3179	5272	8401	0	0	0
Siegfried	286	2920	5415	10000	2423	5221	10000	(497)	(194)	0
Bagley - Graceton	113	1305	2838	7520	1305	2826	7520	(0)	(12)	0
Nottingham	346	1128	2310	9476	1147	2338	9476	19	28	0
PA Central	330	911	7649	10000	1102	7191	10000	192	(458)	0
Keystone	99	1358	2605	6535	1358	2630	6535	(0)	25	0

Table 8 Proposed LS Power Acquisition off peak hours pre and postacquisition HHIs by constraint: 2019

		Pre HHI			Post HHI			Change in HHI		
Facility	Market Hours	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
Conastone - Peach Bottom	1888	863	2003	9736	874	2004	9736	11	1	0
Conastone	102	893	1506	3504	895	1520	3504	2	14	0
Graceton - Safe Harbor	521	1051	2595	8407	1051	2600	8407	(0)	5	0
Wescosville	38	3065	5487	8581	3065	5717	9452	0	230	871
Siegfried	238	2240	5345	10000	2458	5120	10000	218	(226)	0
Bagley - Graceton	56	1100	3165	7485	1102	3147	7485	2	(18)	0
Nottingham	222	1111	2425	6279	1116	2440	6279	5	15	0
PA Central	321	1724	7742	10000	1724	7456	10000	0	(287)	0
Keystone	102	1352	3956	8145	1352	3957	8145	0	1	0

Table 9 Proposed LS Power Acquisition all hours pre and postacquisition HHIs by constraint: 2019

		Pre HHI			Post HHI			Change in HHI		
Facility	Market Hours	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
Conastone - Peach Bottom	4,043	863	1881	9736	861	1888	9736	(2)	7	0
Conastone	272	893	1492	4646	895	1500	4646	2	8	0
Graceton - Safe Harbor	754	1051	2725	8407	1051	2732	8407	(0)	7	0
Wescosville	120	3065	5340	8581	3065	5413	9452	0	73	871
Siegfried	524	2240	5384	10000	2423	5175	10000	183	(208)	0
Bagley - Graceton	169	1100	2946	7520	1102	2932	7520	2	(14)	0
Nottingham	568	1111	2355	9476	1116	2378	9476	5	23	0
PA Central	651	911	7695	10000	1102	7321	10000	192	(374)	0
Keystone	201	1352	3290	8145	1352	3303	8145	0	13	0

Specific Constrained Market HHI Results

Table 10 provides, for the specified constraints under the LS Power Acquisition, by pre and post acquisition HHI category, the number of market hours where the proposed LS Power acquisition would have increased the HHI by 50 or less, more than 50 and less than or equal to 100, and more than 100 points, and failed the thresholds in the 1992 Guidelines.

The HHI results indicate that, according to the 1992 Guidelines, in the Conastone–Peach Bottom market, postacquisition 7.7 percent of market hours “potentially raise significant competitive concerns,”; in the Graceton - Safe Harbor market, 14.9 percent of market hours “potentially raise significant competitive concerns,” in the Wescosville market, 11.7 percent of post market hours “potentially raise significant competitive concerns,” and in the Nottingham market, 12.1 percent of the post market hours “potentially raise significant competitive concerns.”

Table 10 Pre and postacquisition market hours by constraint, HHI, HHI Change, and Percent Raising Competitive Concerns: 2019

		Market Hours						
					Pre to Post HHI Change			
Facility	HHI Range	Pre	Post	Change	0 to 50	50 to 100	More than 100	Percent Raising Competitive Concerns
Conastone - Peach Bottom	Less than 1000	32	34	2	16	0	0	
	1000 to 1800	2,219	2,181	(38)	722	114	144	3.6%
	More than 1800	1,792	1,828	36	360	52	115	4.1%
	Total	4,043	4,043	0	1,098	166	259	7.7%
Conastone	Less than 1000	27	25	(2)	24	0	0	
	1000 to 1800	182	183	1	77	11	3	1.1%
	More than 1800	63	64	1	10	1	0	0.4%
	Total	272	272	0	111	12	3	1.5%
Graceton - Safe Harbor	Less than 1000	0	0	0	0	0	0	
	1000 to 1800	156	141	(15)	49	20	7	0.9%
	More than 1800	598	613	15	133	33	72	13.9%
	Total	754	754	0	182	53	79	14.9%
Wescosville	Less than 1000	0	0	0	0	0	0	
	1000 to 1800	0	0	0	0	0	0	0.0%
	More than 1800	120	120	0	5	2	12	11.7%
	Total	120	120	0	5	2	12	11.7%
Siegfried	Less than 1000	0	0	0	0	0	0	
	1000 to 1800	0	0	0	0	0	0	0.0%
	More than 1800	524	524	0	16	0	4	0.8%
	Total	524	524	0	16	0	4	0.8%
Bagley - Graceton	Less than 1000	0	0	0	0	0	0	
	1000 to 1800	30	30	0	6	0	1	0.6%
	More than 1800	139	139	0	22	2	2	2.4%
	Total	169	169	0	28	2	3	3.0%
Nottingham	Less than 1000	0	0	0	0	0	0	
	1000 to 1800	152	139	(13)	48	9	13	2.3%
	More than 1800	416	429	13	89	25	31	9.9%
	Total	568	568	0	137	34	44	12.1%
PA Central	Less than 1000	2	0	(2)	0	0	0	
	1000 to 1800	3	5	2	1	0	3	0.5%
	More than 1800	646	646	0	4	0	3	0.5%
	Total	651	651	0	5	0	6	0.9%
Keystone	Less than 1000	0	0	0	0	0	0	
	1000 to 1800	17	16	(1)	5	1	2	1.0%
	More than 1800	184	185	1	62	5	3	4.0%
	Total	201	201	0	67	6	5	5.0%

Fast Start Unit Market Results

The IMM calculated the capacity that is currently offered into the PJM market that is eligible to be fast start using PJM's definition. The set of fast start units includes units that have PJM approved unit specific parameter limits that would make them eligible as fast start, and units that did not go through the unit specific parameter review but submitted energy market parameters in the first four months of 2020 that would make them eligible to be fast start. Based on the IMM's calculation, LS Power had a 23.6 percent share of capacity that would be eligible to offer as fast start resources in the PJM market. With the acquisition of Yards Creek, LS Power's market share of fast start capacity in PJM increases to 26.7 percent.

Table 11 shows the HHI and LS Power's market share for fast start capacity before and after the acquisitions in the PJM market. Table 11 shows that the HHI of fast start capacity increases by 148 points, or 13 percent postacquisition compared to the HHI preacquisition in the PJM market.

Table 11 Impact of LS Power acquisition on fast start capacity in PJM

PJM RTO	Preacquisition	Postacquisition
Fast start ICAP owned by LS Power	3,158	3,578
Total fast start ICAP	13,399	13,399
Market share	23.6%	26.7%
HHI	1103	1251

Table 12 shows the HHI and LS Power's market share for fast start capacity before and after the acquisitions in the Mid-Atlantic and Dominion (MAD) region of PJM. Table 12 shows that the HHI of fast start capacity increases by 187 points, or 12 percent postacquisition compared to the HHI preacquisition in the MAD region.

Table 12 Impact of LS Power acquisition on fast start capacity in MAD region

Mid-Atlantic and Dominion Region	Preacquisition	Postacquisition
Fast start ICAP owned by LS Power	1,685	2,105
Total fast start ICAP	8,681	8,681
Market share	19.4%	24.2%
HHI	1502	1689

The market for fast start units in PJM is moderately concentrated. The change in the HHI in PJM with the LS Power acquisitions is 148 points, greater than 100, exceeding the 1992 Guidelines' threshold. The change in the HHI in the MAD region of PJM with the LS Power purchases is 187 points, greater than 100, exceeding the 1992 Guidelines' threshold.

The market for fast start units is a relevant market in evaluating the Yards Creek acquisition. In the real-time energy market, there are no substitutes for fast start units under conditions that occur frequently, including rapid increases in load, load exceeds PJM's load forecasts, and units fail to follow dispatch. PJM hourly load changes can reach levels near the total fast start capacity. PJM relies on pumped hydro units for rapid ramping and on the commitment of fast start combustion turbines and reciprocating engines to meet unanticipated increases in load. Table 13 shows the number of hours when the PJM hourly load increased by more than 4,000 MW from one hour to the next. When the PJM system requires fast start units, fast start units have market power.

Table 13 PJM Hourly Load Increase: 2019

Load Increase Exceeds MW	Hours	Percent of Hours
4,000	1,162	13.3%
5,000	681	7.8%
6,000	360	4.1%
7,000	202	2.3%
8,000	58	0.7%

Capacity Market Results

The Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region on June 1, 2007. The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[34]

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[35] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer

34 *See* 126 FERC ¶ 61,275 at P 86 (2009).

35 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

The RPM capacity market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective, and of explicitly limiting the exercise of market power.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. Local markets may have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. Thus, the reliability goal is to have total supply equal to or slightly above the demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The level of elasticity incorporated in the RPM demand curve, called the Variable Resource Requirement (VRR) curve, is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. Given the basic features of the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the potential for the exercise of market power is high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market.

Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Attenuation of those rules would mean that market participants would not be able to rely on the competitiveness of the market outcomes. However, the market power rules are not perfect and, as a result, competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance.

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM capacity market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test and the resultant offer capping.

Unfortunately, the current PJM market power mitigation rules in the capacity market are not effective. As a result of using an unreasonable and unsupported number of expected PAI (PAH) with the current nonperformance charge rate based on 30 hours, the default market seller offer cap (MSOC) is overstated. This means that only a small number of very high offers are subject to unit specific cost review for market power. Most offers, including the offers setting price, are not subject to unit specific cost review for market power. An excessive default MSOC prevents effective mitigation of market power in the PJM Capacity Market. The lack of effective market power mitigation in the capacity market, where structural market power is endemic, is unjust and unreasonable.[36]

Markets

The analysis of the impact of the merger on the capacity market examines the locational markets defined by the underlying economics of the market including supply and demand curves and transmission constraints. Each transmission zone is a Locational Deliverability Area (LDA) which can be a separate market if PJM models the zone as an LDA and market conditions result in price separation in an auction. There are, in addition, several subzonal LDAs, including PSEG North, DPL South, and ATSI Cleveland.

For the defined markets, market concentration and HHI levels were calculated on a preacquisition and a postacquisition basis for each market.

As in the energy market, to the extent that total RTO demand for capacity can be met without any constraints binding, the optimal solution is defined by the intersection of the aggregate supply and demand curves. However, if the next increment of demand for capacity in an LDA cannot be met by the next economic increment of supply, regardless of location, and must be met by supply within the LDA, then the transmission constraint is binding and there is a separate market created. That separate market is defined by the incremental demand that must be met by capacity within the LDA and the incremental

36 *See* Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (Feb. 21, 2019).

supply within the LDA available to meet that demand, above that which would have cleared at the RTO price.

The ability to exercise market power in the LDA is determined by the ownership structure of the incremental supply and the relationship between incremental supply and incremental demand. The ability to exercise market power can be measured most accurately by the TPS test, applied to the incremental supply of capacity, but can also be measured by the HHI, applied to the total cleared supply of capacity in the LDA. The incentive to exercise market power in the LDA is a function of the ownership structure of all capacity in the LDA. Regardless of offer price and regardless whether the capacity was incremental, all capacity in a constrained LDA receives the higher constrained clearing price. The ability to exercise market power can be measured most accurately by the TPS test while the HHI provides a measure of the incentive to exercise market power.

When RPM clears as a single market, total RTO supply and demand determine the clearing price and all resources receive the clearing price. The market definition is clear. When an LDA within the RTO clears as a separate market, the incremental locational supply available to meet the locational demand determines the clearing price for the LDA. All capacity resources in the LDA receive the clearing price, regardless of whether the capacity resources are incremental.

When there are multiple LDAs that clear as separate markets and the LDAs are not overlapping, the logic is exactly the same for each LDA separately and its relationship to the rest of RTO.[37] When the LDAs are nested, the analysis becomes more complex.

Analysis

The Yards Creek capacity resources are modeled in the Rest of EMAAC LDA. The Hummel (Sunbury) capacity resource is modeled in the Rest of MAAC LDA. The Yards Creek capacity resources are not subject to the capacity performance must offer requirement under PJM Market Rules because they are capacity storage resources.[38] {BEGIN CUI//PRIV} [redacted] {END CUI//PRIV}

[37] See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," at Attachment A <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

[38] *See* OATT Attachment DD § 6.6A(c).

For this analysis, the actual sell offer prices and offered MW quantities in the 2020/2021 and 2021/2022 RPM BRAs were used.[39]

Total Market Analysis

HHI Analysis

Table 14 shows pre and post LS Power acquisition HHIs for the 2020/2021 and 2021/2022 RPM Base Residual Auctions, including all modeled LDAs for each BRA. The HHIs in Table 14 measure concentration of ownership for all cleared capacity in the identified LDAs. The effect of the LS Power acquisition is a slight increase in the RTO HHIs in both the 2020/2021 and 2021/2022 RPM BRAs and a decrease in MAAC and EMAAC. The decrease in the HHI for MAAC is a result of the offsetting decrease in the market shares of PSEG and Panda. The decrease in HHIs for EMAAC is a result of the offsetting decrease in the market share of PSEG.

[39] It the ownership of assets changed between the operation of the BRA and the present, the current parent company ownership was used in both the preacquisition and postacquisition cases.

Table 14 Preacquisition and postacquisition HHI results

RPM Auction	RPM Market	Preacquisition HHI	Postacquisition HHI	Change in HHI
2020/2021 Base Residual Auction	RTO	538	541	4
	MAAC	800	793	(7)
	EMAAC	1365	1343	(22)
	SWMAAC	2186	2186	0
	DPL South	2401	2401	0
	PSEG	4447	4447	0
	PSEG North	4773	4773	0
	Pepco	4439	4439	0
	ATSI	3007	3007	0
	ATSI Cleveland	6965	6965	0
	ComEd	2065	2065	0
	BGE	4946	4946	0
	PPL	3576	3576	0
	DAY	3295	3295	0
	DEOK	2632	2632	0
2021/2022 Base Residual Auction	RTO	507	514	7
	MAAC	755	750	(5)
	EMAAC	1233	1215	(17)
	SWMAAC	2317	2317	0
	DPL South	2383	2383	0
	PSEG	4000	4000	0
	PSEG North	4342	4342	0
	Pepco	4743	4743	0
	ATSI	1311	1311	0
	ATSI Cleveland	3219	3219	0
	ComEd	1591	1591	0
	BGE	3453	3453	0
	PPL	3667	3667	0
	DAY	2847	2847	0
	DEOK	4805	4805	0

Incremental Market Analysis

Pivotal Supplier Analysis

The incremental analysis addresses the ability of owners to exercise market power.

The market for a constrained LDA is defined by the incremental supply available to meet the incremental demand when locational incremental demand must be met by capacity resources within the LDA. The RTO market is defined to include all supply that is not incremental supply in a constrained LDA. The RTO market includes all MW that resulted in the clearing price for the rest of RTO.

The three pivotal supplier (TPS) test measures the degree to which the incremental supply from three suppliers of capacity is required in order to meet the incremental demand in an LDA. The demand consists of the incremental MW of capacity required to relieve a constraint or clear a market. The supply consists of the incremental MW of supply available to relieve the constraint or clear the market.

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Regulation Market Results

Table 16 shows the HHI for RegA, RegD and the entire regulation market, for 2019. In 2019, the average HHI of RegA resources was 2415 which is highly concentrated, and the average HHI of RegD resources was 1380 which is moderately concentrated. The weighted average HHI of all resources was 1412, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources reflect the fact that different owners have large market shares in the RegA and RegD markets.

Table 16 Regulation Market HHI, 2019

	All Reg	RegA	RegD
HHI	1412	2415	1380

Table 17 shows the monthly three pivotal supplier test results for the regulation market, in 2019. In 2019, the three pivotal supplier test was failed an average of 90.6 percent of hours each month. The PJM Regulation Market in 2019 was characterized by structural market power.

Table 17 Regulation Market monthly three pivotal supplier results, 2019

Month	Percent of Hours Pivotal
Jan	77.8%
Feb	76.0%
Mar	93.3%
Apr	93.1%
May	94.0%
Jun	91.0%
Jul	92.7%
Aug	93.1%
Sep	93.3%
Oct	96.1%
Nov	90.7%
Dec	96.1%
Average	90.6%

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Despite the fact that the IMM has concluded that prior regulation market results were competitive, the presence of structural market power, no must offer requirement, and a small number of resources providing regulation in any given hour, the regulation market is extremely sensitive to changes in market behavior. Resources with the ability to provide both RegA and RegD products, like pumped storage hydro units, have the ability to alter market outcomes, as they have done in the case of dual offers and RegD offers.

If LS Power offers Yards Creek and Hummel in the regulation market, its market shares will increase, HHI will increase and TPS failures will increase. The IMM cannot provide detailed postacquisition results for the regulation market because such results would require reclearing the market based on behavioral assumptions.