UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NEW YORK PUBLIC SERVICE COMMISSION, NEW YORK POWER AUTHORITY, AND NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY	)	
COMPLAINANTS,	)	
V.	)	**DOCKET NO. EL15-___-000**
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.	)	
RESPONDENT.	)	

COMPLAINT OF THE
NEW YORK PUBLIC SERVICE COMMISSION,
NEW YORK POWER AUTHORITY, AND
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Pursuant to sections 206 and 306 of the Federal Power Act ("FPA")[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the New York Public Service Commission ("NYPSC") the New York Power Authority ("NYPA"), and the New York State Energy Research and Development Authority ("NYSERDA") (collectively, "Complainants") hereby submit this complaint ("Complaint") against the New York Independent System

[1] 16 U.S.C. §§ 824e, 825e (2012).

[2] 18 C.F.R. § 385.206 (2014).

Operator, Inc. ("NYISO"). The Complaint seeks revisions to the buyer-side market power mitigation measures contained in section 23.4 of Attachment H of the NYISO's Market Administration and Control Area Services Tariff ("Market Services Tariff"). These mitigation measures are currently imposed arbitrarily in an overbroad manner on all new entrants into the NYISO's mitigated Installed Capacity ("ICAP") market zones, regardless of whether the new entrant has the intention, incentive, and ability to exercise buyer-side market power to inappropriately depress market clearing prices. As demonstrated herein, these rules are unjust and unreasonable, unduly discriminatory, and preferential. The Complainants seek revisions to the Market Services Tariff that would result in buyer-side market power mitigation ("BSM") rules that are just and reasonable, and not unduly discriminatory or preferential.[3]

The Complainants note that the Commission recently granted a complaint seeking a Competitive Entry Exemption ("CEE") from the BSM rules.[4] While Complainants support the adoption of a CEE, making that modification alone leaves NYISO BSM rules that remain unjust and unreasonable, because they will continue to over-mitigate, thereby interfering with the proper operation of the markets. The Commission's action on CEE also makes this Complaint more urgent. The new resources that enter under the CEE will

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3 While these set of rules are commonly referred to as the BSM rules, this is a misnomer and they might better be called "all new source mitigation" rules. Complainants note that the rules apply broadly to all new entry in the affected zones and not just to conduct that could reasonably be considered an attempt to exercise buyer-side market power.

4 *Consol. Edison Co. of N.Y., Inc. v. N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,139 (2015) ("*Consolidated Edison*"). The Commission also recently denied a complaint that sought to exclude certain existing capacity resources from the capacity market. *See Indep. Power Producers of New York, Inc. v. New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,214 (2015) ("*IPPNY*"). The Commission did, however, direct the NYISO to "establish a stakeholder process to consider (1) whether there are circumstances that warrant the adoption of [BSM] rules in the rest-of-state; and (2) whether resources under repowering agreements . . . have the characteristics of new rather than existing resources, triggering a buyer-side market power evaluation . . . and what mitigation measures need to be in place" for those agreements. *Id.* at P 71.

potentially make it even more difficult for resources like renewables, transmission coupled with unforced capacity deliverability rights ("UDRs"),[5] and self-supply resources to qualify under the existing BSM rules.

This Complaint is filed at this time in response to the Commission's repeated suggestions that concerns with the NYISO's BSM rules are best addressed through the complaint process.[6] Moreover, the NYISO stakeholder process, the first step to revising NYISO rules in many instances,[7] is not a viable option here. It is currently over-burdened, presently addressing the compliance obligation the Commission directed in response to the complaint filed by the Independent Power Producers of New York, Inc. in Docket No. EL13-62-000 as well as other proceedings the Commission has recently returned to the NYISO.[8] While those processes address the existing BSM rules piecemeal, this Complaint seeks a fundamental shift in the design of the BSM program, to focus it on those circumstances where a need for mitigation could actually arise. In contrast, the current overbroad application of the BSM rules poses unjust and unreasonable threats to the proper operation of the competitive market and erects

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[5] Transmission facilities alone are not subject to mitigation under the NYISO market rules, nor should they be. However, an entity that builds a controllable transmission line and secures from the NYISO Unforced Capacity Deliverability Rights in order to import capacity from a resource located in one capacity region into another locality is subject to the BSM new entry mitigation rules for the combined transmission and UDR project. Given the expense and long lead time required to build a controllable transmission line, it clearly would not be a type of resource that would be chosen as a vehicle by which to attempt to exercise market power and therefore should not be subject to BSM mitigation.

[6] *N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,208 at P 30 (2015); *N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301 at P 38 (2008).

[7] *See, e.g.*, *ISO New England Inc.*, 130 FERC ¶ 61,145 at P 34 (2010); *ISO New England Inc.*, 125 FERC ¶ 61,154 at P 39 (2008); *ISO New England Inc.*, 128 FERC ¶ 61,266 at P 55 (2009); *N.Y. Indep. Sys. Operator, Inc.*, 126 FERC ¶ 61,046 at PP 53-54, *order on clarification*, 126 FERC ¶ 61,214, *order on reh'g, clarification & compliance*, 127 FERC ¶ 61,318 (2009); *New England Power Pool*, 107 FERC ¶ 61,135 at PP 20, 24 (2004).

[8] *IPPNY*, 150 FERC ¶ 61,214 at P 71; *see also New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116 (2015).

obstructions against addressing pressing public policy goals. Therefore, the BSM rules should be addressed promptly without undergoing the delays that would attend a protracted stakeholder process distracted by competing priorities under more stringent deadlines.

To accomplish the goals of this Complaint, the Commission should direct that the NYISO make the changes to BSM rules proposed in this Complaint by revising its tariff. The NYISO could be directed to make the tariff filing within 90 days of the order's issuance after consultation with interested stakeholders, thereby arranging for their input without a full stakeholder process while still expeditiously implementing the new BSM rules needed to avoid harms to the market and prevent obstruction of public policy goals. Alternatively, should the Commission determine additional procedures are needed before all of the issues can be resolved, it could set the matter for hearing and appoint a settlement judge to ensure the more prompt and efficient considerations of the Commission's concerns than could be accomplished in the overburdened NYISO stakeholder process.

Whatever procedures are selected, as supported below, the Commission should direct the NYISO to implement a just and reasonable approach that will: (1) target only those types of projects whose deployment would enable a capacity buyer with the incentive to exercise buyer market power to manipulate capacity market prices; (2) exempt from mitigation qualifying self-supply arrangements, in addition to those that qualify for the CEE; and (3) exempt from mitigation those resources developed to address certain reliability needs.[9]

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[9] Attachment 1 to the Complaint illustrates the steps to the BSM evaluation the Complainants propose.

I. EXECUTIVE SUMMARY

The current NYISO BSM rules, even with the impending addition of a CEE, are unjust and unreasonable, because they subject all new resources in mitigated capacity zones ("MCZ") to mitigation, resulting in over-mitigation, and inefficient and uneconomic results, thereby thwarting the proper functioning of the NYISO's ICAP market. The mitigation provisions in the NYISO Market Services Tariff are ostensibly designed to ensure that the ICAP market clearing prices reflect competitive outcomes. In applying mitigation to all new resources that could enter a mitigated zone, the rules presume that new supply is "guilty" until either shown to be exempt or proven innocent. Moreover, the tests used to evaluate whether or not a new unit is "economic" are fundamentally flawed and result in the mitigation of projects that bear no rational relationship to a potential exercise of buyer market power.[10] These deficiencies deter and thwart new entry, while preserving the status quo to the benefit of incumbent suppliers. The result undermines the competitiveness of the market.

This Complaint seeks to correct the inherent flaws in the current arbitrary and overbroad NYISO BSM rules. The modifications to those rules proposed here would more properly focus mitigation on only those projects of legitimate concern that could potentially enable a buyer to inappropriately exercise market power.

[10] As noted above, the Commission recently found the application of the current BSM rules to pure merchant entrants who fund their projects without subsidies from entities with buyer-side market power was unjust and unreasonable. *Consolidated Edison*, 150 FERC ¶ 61,139. Simply adding a CEE in the BSM rules, however, is not enough to result in a properly functioning ICAP market and the Complainants request that the Commission order the relief sought in the instant Complaint.

II. COMMUNICATIONS

Complainants request that all correspondence and communications concerning this filing be sent to each of the following persons and that each are included on the Commission's official service list for this filing:[11]

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III. DESCRIPTION OF COMPLAINANTS AND RESPONDENT

A. NYPSC

The NYPSC is a regulatory body established under the laws of the State of New York with jurisdiction to regulate rates and charges for the sale of electric energy to

[11] Complainants respectfully requests waiver of 18 C.F.R. § 385.203(b)(3) to allow each person listed to be included on the Commission's official service list for filing.

consumers within the State. The NYPSC is therefore a State Commission as defined in section 3(15) of the FPA.[12]

The Commission previously recognized the role of the NYPSC in developing the ICAP "Demand Curve" to ensure it will "adequately and reliably serve customers' needs over the short and long term," and found that the NYPSC is "better placed to establish the appropriate ICAP quantity New York requires to serve those customers."[13] In addition, the FPA reserves jurisdiction to states, which includes the NYPSC, to "set and enforce compliance with standards for [the] adequacy . . . of electric facilities."[14] The NYPSC has implemented an Installed Reserve Margin ("IRM") requirement that is designed to ensure that sufficient margins of reserve generation are installed so that the probability of disconnecting firm load, due to resource deficiencies, will occur no more than once every 10 years. The NYPSC approved the current IRM for the New York Control Area of 17.0 percent of forecasted peak load.[15]

B. NYPA

NYPA is a corporate municipal instrumentality and a political subdivision of the State of New York, organized under the laws of New York, and operates pursuant to Title 1 of Article 5 of the New York Public Authorities Law. NYPA is a "state instrumentality" within the definition of section 201(f) of the FPA.[16] It is engaged in the generation, transmission, and sale of electric power and energy at wholesale and retail

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[12] 16 U.S.C. § 796(15).

[13] *N.Y. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 at P 15, *reh'g denied*, 105 FERC ¶ 61,108 (2003).

[14] 16 U.S.C. § 824*o*(i)(2).

[15] *See Installed Reserve Margin*, Order Adopting Installed Reserve Margin for the New York Control Area for the 2014-2015 Capability Year, Case 07-E-0088, et al. (issued Feb. 24, 2014).

[16] 16 U.S.C. § 824(f) ("No provision in this subchapter shall apply to, or be deemed to include . . . a State or any political subdivision of a State . . . or any agency, authority, or instrumentality of any one or more of the foregoing. . . ."); *see also Village of Bergen v. FERC,* 33 F.3d 1385, 1389 (D.C. Cir. 1994).

throughout New York, and is a founding member of the NYISO. NYPA's bulk power transmission system encompasses approximately 1,400 circuit miles, and consists of facilities ranging from 115 kV to 765 kV. NYPA is an unusually diverse market participant because its various business interests include the following substantive areas that are addressed, in one fashion or another, in the NYISO markets: generation owner, transmission owner, demand response participant, load serving entity, and a municipal utility. NYPA's various interests, and its public purpose as stated in its statutory charter, lead it to look broadly at appropriate market structures without facing the pressure of satisfying any single business interest.

NYPA has no distribution facilities and virtually all of NYPA's customers are connected to the transmission and distribution systems of other public utilities. As the Commission has recognized, NYPA, unlike other public utilities, does not have a defined, integrated service area; instead, "its customers are located in the service areas of other transmission providers, and . . . pay for transmission service based on the costs of the transmission providers where the loads are located."[17] NYPA's customers are located throughout the State of New York, in both upstate and downstate areas, and include both wholesale power purchasers and end users. NYPA also serves customers in states other than New York. As the largest state-owned power organization in New York, NYPA has taken the responsibility for constructing, owning, and operating critical segments of transmission and generation infrastructure throughout the State. NYPA owns or has contracts with substantial generation resources in New York State, including certain

[17] *Cent. Hudson Gas & Elec. Corp.*, 103 FERC ¶ 61,143 at P 30 (2003).

resources that are currently mitigated and are subject to the Minimum Offer Floor Requirement.

C. NYSERDA

NYSERDA was established in 1975 as a public benefit corporation whose mission is to address the State's energy and environmental issues. NYSERDA administers a suite of statewide clean distributed energy resource ("DER") initiatives, including: energy efficiency, demand management, demand response, distributed generation, energy storage, and both large and small-scale renewable energy programs. NYSERDA also manages innovation, research and market development initiatives that support state policy, foster clean energy markets, and support utility efforts to integrate clean DER and enable customer choice.

D. NYISO

In accordance with its Market Services and Open Access Transmission Tariffs, the NYISO is the entity responsible for providing non-discriminatory open access transmission service, maintaining reliability, and administering competitive wholesale markets for electricity, capacity, and ancillary services in New York State. The NYISO is also responsible for implementing the mitigation measures at issue in this Complaint pursuant to the provisions of its Market Services Tariff.

IV. BACKGROUND

The NYISO administers capacity, energy, and ancillary services markets pursuant to its Market Services Tariff. The ICAP market is designed to encourage new investment and to inform retirement decisions by providing a price signal that indicates when sufficient capacity is available or when additional ICAP resources are needed to meet

New York's peak demand and maintain its planning reserve margin.[18] Any real or perceived barrier to new entry will prevent market participants from responding to market signals, jeopardizing the market's ability to meet resource adequacy needs in the most efficient manner possible.

Under the NYISO's ICAP market rules, mitigation measures apply to only two MCZs: New York City and the "New Capacity Zone" which covers the Lower Hudson Valley as well as New York City (commonly referred to as the G-J Locality).[19] Mitigation is not imposed in other NYISO zones because there has been no finding that buyers and sellers in those zones have the ability to profit from the inappropriate exercise of market power.[20]

The mitigation measures in effect in the MCZs include both offer cap mitigation, which is intended to counteract incentives for suppliers to raise prices above competitive levels, and offer floor mitigation, which is intended to counteract incentives for buyers to suppress prices below those levels. The Commission has determined that BSM is an appropriate means to prevent the artificial suppression of market prices for capacity attributable to the entry of projects, that would otherwise be uneconomic but for subsidization by net buyers with an intent and incentive to depress capacity prices.[21] The

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[18] The installed capacity market in the NYISO is commonly referred to as the "ICAP Market."

[19] Mitigated Capacity Zones include "New York City and any Locality added to the definition of 'Locality' accepted by the Commission on or after March 31, 2013." NYISO Market Administration and Control Area Services Tariff § 2.13 (2015), *available at* http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp. On August 13, 2013, the Commission accepted the NYISO's proposal to define a new capacity zone consisting of Load Zones G through J. *N.Y. Indep. Sys. Operator, Inc.*, 144 FERC ¶ 61,126 (2013).

[20] As noted, the Commission recently established a 90-day stakeholder process to consider whether circumstances warrant the adoption of BSM rules in the rest-of-state. *See IPPNY*, 150 FERC ¶ 61,214 at P 71.

[21] *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 101, *order on reh'g & compliance*, 124 FERC ¶ 61,301 (2008) ("A large net buyer could acquire new capacity that is not needed in the market and whose

BSM provisions were intended to deter such behavior and assure that market clearing prices reflect competitive outcomes.[22]

However, despite this relatively narrow purpose, the current BSM rules require the NYISO to scrutinize every new resource in a mitigated zone, to determine whether it qualifies for an exemption or to determine if it is "economic." To make the latter determination, the NYISO performs two tests: the so-called Part A and Part B tests. The Commission recently offered the following description of the two mitigation tests:

> NYISO's Market Monitoring Unit [("MMU")] describes the Part A test as "compar[ing] a forecast of capacity prices in the first year of an Examined Facility's operation to the Default Offer Floor, which is 75 percent of the net [cost of new entry ("CONE")] of the hypothetical unit modeled in the most recent Demand Curve reset," such that a new entrant is exempted "if the price forecast for the first year is higher than the Default Offer Floor." Under the Part B test, NYISO "compares a forecast of capacity prices in the first three years of an Examined Facility's operation to the net CONE of the Examined Facility," such that a new entrant is exempted "if the price forecast for the three years is higher than the net CONE of the Examined Facility."[23]

The intent of both tests is to exempt from mitigation a unit deemed "economic" as compared to the NYISO forecast. If a unit passes either Part A or Part B, it is exempt from mitigation and is eligible to bid in the capacity market on the same basis as existing capacity resources. Otherwise, it will be subjected to mitigation and may well be precluded from earning NYISO capacity market revenues.

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costs exceed the market price. Such an investment would be inefficient, the net buyer would lose money on the capacity, and no rational seller would knowingly make such an investment. . . . The mitigation of net buyers' sales of capacity proposed by NYISO should help avoid this.") The Commission initially determined in 2008 that BSM rules should apply to "net buyers" only, but on rehearing of its decision, the Commission eliminated the restriction.

22 *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 103.

23 *Consolidated Edison*, 150 FERC ¶ 61,139 at P 6 (internal citations omitted).

Even with the CEE, the BSM rules continue to cast the risk of mitigation over all new market entrants, and any resource returning from a repowering, in a mitigated zone. The BSM rules also apply to demand response resources. The Complainants believe that demand response resources should not be subject to potential mitigation in the first instance. The result is unjust and unreasonable over-mitigation that impairs the efficient operation of the capacity markets to the detriment of consumers. As discussed below, however, the BSM rules may be constrained to their proper ambit through restricting their application solely to new gas or oil-fired units. Those types of units are the only realistic option a net buyer, with an incentive to exercise buyer market power, can successfully deploy to achieve market price suppression.

V. COMMUNICATIONS WITH NYISO

In advance of filing the instant Complaint, the Complainants reached out to the NYISO to explain their preferred approach to addressing buyer-side mitigation. In conducting several discussions with NYISO, the Complainants outlined their proposed revisions to the BSM rules and shared a draft of this complaint.

VI. COMPLAINT

A. <u>Requested Relief</u>

The Complainants request that the Commission make the following findings:

1. That the NYISO's BSM rules are unjust and unreasonable because they prevent the ICAP market from functioning properly.
2. That the BSM rules should apply to only a limited subset of generation facilities: namely, new gas- or oil-fired simple and combined cycle units.
3. That the re-focused BSM rules should include, in addition to the CEE, a self-supply exemption ("SSE") and a reliability exemption.
4. That the NYISO be ordered to make a compliance filing revising its Market Services Tariff consistent with the Commission's findings

upon this Complaint, or, in the alternative, the Commission set the matter for hearing while providing for a settlement process.

B. Argument

1. The current BSM rules are unjust and unreasonable and require modification.

The NYISO's BSM rules are unjust and unreasonable, primarily because they are over broad and secondarily because the tests for mitigation rely on flawed assumptions. In a competitive market, the equilibrium of the market is the point where the supply curve (reflecting the seller's marginal cost) and the demand curve (reflecting the buyer's marginal value) intersect. The *inappropriate* exercise of market power and other forms of manipulation have the potential to distort a competitive marketplace, preventing it from achieving competitive equilibrium and reducing social welfare below its maximum.[24] Valid concerns regarding market power and manipulation can be addressed through appropriately-tailored mitigation measures. A properly designed mitigation measure that targets what the Commission has called "actual buyer-side market power,"[25] but not all resources indiscriminately, can counteract the effects of market power or manipulation and move the market closer to its competitive equilibrium. But mitigation measures that are overly broad can be just as damaging to a competitive marketplace as the *inappropriate* exercise of market power or manipulative conduct, as imposing imprecise or misdirected mitigation measures can pervert market outcomes and cause

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[24] The U.S. Department of Justice defines market power as "ability of one or more firms profitably to maintain prices above competitive levels for a significant period of time" and states that market power also "encompasses the ability of a single buyer or group of buyers to depress the price paid for a product to a level that is below the competitive price." U.S. Department of Justice Merger Guidelines § 1 (June 14, 1984), *available at* http://www.justice.gov/atr/hmerger/11249.htm. This latter concept is commonly referred to as buyer-side market power. *See* Affidavit of Thomas S. Paynter at 14:2-13 (attached hereto as Exhibit A).

[25] *Consolidated Edison*, 150 FERC ¶ 61,139 at P 3.

substantial deviations from the competitive equilibrium, much to the detriment of the social welfare.[26]

It is important to recognize what mitigation cannot do and should not do. As discussed in his affidavit, affiant Cadwalader demonstrates that mitigation cannot increase social welfare to a level higher than what would prevail at competitive equilibrium.[27] Mitigation should not be used as a mechanism to maintain at artificially elevated levels the prices incumbents receive by erecting a barrier to entry that moves the market away from, rather than closer to, the competitive equilibrium.

In considering mitigation measures, two issues should be carefully evaluated. First, is it likely that acting in an anticompetitive manner is in a market participant's interest? If not, then there is a substantial probability that the application of mitigation will move the market away from competitive equilibrium rather than towards it.

Second, how can the likelihood that a market participant has an incentive to act in an anti-competitive manner be forecast with the precision sufficient to justify mitigating that participant? A market participant's assumptions and forecasts of future market conditions may vary significantly from the assumptions and forecasts used by the NYISO. These differences are not the result of manipulative intent by the market participant, but instead reflect honest differences of opinion. When mitigation measures are imposed in reliance on a variety of forecasts and estimates about which reasonable persons can disagree, mitigation is less likely to produce improvements that move the market closer to a competitive equilibrium.

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[26] *See* Affidavit of Michael D. Cadwalader ¶ 12 (attached hereto as Exhibit B).

[27] *Id.* ¶ 11.

The purpose of BSM is to address the first issue. BSM is intended to prevent buyer-side entities from unfairly or intentionally suppressing capacity prices by developing unnecessary generation or devoting subsidies to the support of otherwise uneconomic projects, for the purpose of subsequently benefitting from the overall price suppression. The Commission has routinely determined that BSM is an appropriate mechanism to address the deleterious effects that would be experienced if projects developed for the purpose of price suppression were allowed to participate in the capacity markets.[28] But preventing the abuse of market power does not justify measures that hinder market operation. FERC has recognized that BSM rules must also provide "flexibility to project developers to implement certain business decisions without inappropriate regulatory restrictions."[29]

FERC further emphasizes the importance of balancing the need to mitigate buyer-side market power with the harmful effect of over-mitigation of projects that do not improperly depress prices.[30] Specifically, mitigation, if applied too broadly, can "wreak substantial harm . . . that could be cured only by attracting new sources of supply."[31] For the market to function properly, the BSM rules must not mitigate projects where there is no intent, incentive, or opportunity to inappropriately suppress market prices.

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[28] *See N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 100; *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 104 (2006), *order on reh'g*, 119 FERC ¶ 61,318 (2007).

[29] *Consolidated Edison*, 150 FERC ¶ 61,139 at P 4.

[30] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 26 (2013) ("By targeting those resources most likely to raise price suppression concerns (*i.e.*, gas-fired resources), adopting exemptions for competitive entry and self-supply, and retaining the unit-specific review process for resources not eligible for the exemptions, we find that the MOPR[Minimum Offer Price Rule] as modified herein appropriately balances the need for mitigation of buyer-side market power against the risk of over-mitigation."); *see also Midwest Indep. Sys. Operator, Inc.*, 111 FERC ¶ 61,043 at P 78 (2005); *New England Power Pool & ISO-New England, Inc.*, 101 FERC ¶ 61,344 at P 28 (2002).

[31] *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 969 (D.C. Cir. 2005).

Once assessed in conformance with these principles, it is apparent that the current NYISO BSM rules are not properly designed and are overly broad. The rules indiscriminately encompass all types of new entry in MCZs, regardless of whether any individual developer intends to and is able to suppress market prices.[32] For example, the current BSM rules inappropriately apply to renewable generation developed in response to efforts to reduce carbon emissions or diversify fuel mix. They also currently apply to any resource, even those developed with *no* intent to exercise monopsony or oligopsony market power to suppress clearing prices, as evidenced by the long lead-time or the high cost of developing the resource (such as a transmission facility coupled with a UDR or a nuclear generation facility) compared to other supply options. The result is over-mitigation that protects incumbents from competition to the detriment of New York consumers and to the State's ability to meet public policy goals and requirements in a reasonable manner.

The NYISO MMU has noted that the tests used under the BSM rules to determine if a resource should be mitigated are highly subjective, can be defective, and are exacerbating the adverse impacts attending the mistaken premise that all new resources must be tested. Because, as described by affiants Cadwalader and Evans, the application of the NYISO's current BSM rules depends upon those flawed tests, the outcome is rules that adversely affect the competitive functioning of its markets, and render them unjust and unreasonable. First, the ICAP price forecasts used in the Part A and Part B tests assume that all mothballed generators, as well as generators that must transfer their

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[32] *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at PP 101, 106. Rather than limiting potential mitigation to resources in which "no rational seller would knowingly make such an investment," the BSM rules apply to all resources regardless of whether there is a rational basis upon which the developer decides to make the investment. *Id.* at P 101.

Capacity Resource Interconnection Service rights before a new unit can offer deliverable capacity, will be in service and sell capacity.[33] These assumptions are unrealistic and unjustified by past experience with mothballed generators. Yet this assumption has the effect of depressing the forecast of ICAP prices as well as the forecast of net energy and ancillary services revenue.[34]

Second, NYISO assumes unrealistic entry dates and understates the effects of delay in applying its tests.[35] For example, NYISO assumed that members of Class Year 2012 would enter service in May 2015; however, as the MMU has noted, this assumption is unrealistic because those resources are actually expected to enter the market anywhere from 2016 to 2018. Moreover, anticipated load growth between 2015 and 2016-2018 would increase the ICAP price forecasts used in the Part A and Part B tests and would increase the energy and ancillary services revenue considered in Part B.[36] Combining that effect with the unsupportable assumptions results in mitigation measures that artificially prevent entry and move the market away from a true competitive equilibrium. The shotgun approach of broadly applying mitigation against all new entrants in mitigated zones exacerbates these effects, resulting in unacceptable risk of over-mitigation.

Third, the Part B test considers only the three-year Mitigation Study Period, which is far shorter than the lifespan of a new generating resource. A new unit whose

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33 Cadwalader Aff. ¶ 29 (citing Potomac Economics, Ltd., *Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2012 Projects* (Jan. 13, 2015)); *see also Consolidated Edison*, 150 FERC ¶ 61,139 at P 16.

34 Cadwalader Aff. ¶ 29; Affidavit of Adam Evans ¶¶ 16-17 (attached hereto as Exhibit C).

35 Cadwalader Aff. ¶ 30; Evans Aff. ¶¶ 14-15.

36 Cadwalader Aff. ¶ 30.

sponsor sees economic justification over the expected life-span of its resource is thus artificially prohibited from entering the market.[37]

Fourth, it is important to note the consequences of the uncertainty inherent in the complex calculations, assumptions, and forecasts used in applying the current BSM rules. Calculating each of the elements in the formula requires the NYISO to "pick" from a range of reasonable alternatives. Compounding this uncertainty is the fact that the process depends upon multiple exercises of judgment by NYISO, yielding a result that represents only one point along a spectrum of possible outcomes. Thus, a project developer making assumptions that are reasonable, but nonetheless different from the NYISO's, and acting without a scintilla of intent to unjustly suppress prices or any means for doing so, could still see its new resource mitigated if its judgments and forecasts do not coincide perfectly with the NYISO's.[38]

Fifth, the BSM rules fail to consider all of the obligations found in the New York Public Service Law. Under the law, New York's distribution utilities have an obligation to provide safe and adequate service at just and reasonable rates, but they also have a duty to do so while preserving environmental values and conserving natural resources.[39] The BSM rules do not recognize that in many instances compliance with the full range of responsibilities applicable to the electric market, including environmental responsibilities, may lead those utilities to seek new resources. For example, New York City has recognized that the current BSM rules hinder its effective cooperation with its local distribution utility for the purpose of meeting goals for replacing or repowering the oldest

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[37] *Id.* ¶ 24.

[38] *Id.* ¶ 32; Evans Aff. ¶¶ 12-13.

[39] N.Y. PUB. SERV. LAW § 5(2) (2015).

and most inefficient power plants located in the City, so that City residents can obtain energy from cleaner, more reliable resources.[40]

The result of these flaws is that an economically justified entrant may be deterred by the very existence of the current BSM rules, even assuming the NYISO could make all of its calculations accurately. The mere existence of the NYISO's assessment creates uncertainty as to the effect of the mitigation offer floor on the ability of a new resource to qualify for receiving ICAP payments, which can deter economic investment in new resources. For example, affiant Cadwalader describes a hypothetical new resource with a Unit Net CONE of $10/kW-mo. facing a market with a 50 percent chance of a $14/kW-mo. ICAP price and a 50 percent chance of an $8/kW-mo. ICAP price. This market participant will be willing to accept the risk of investing because the expected return is $11/kW-mo (averaging $14 and $8). However, if the NYISO ICAP forecast is less than $10/kW-mo. and the new resource is subject to a NYISO-imposed $10/kW-mo. offer floor, then there is a 50 percent chance that the resource will receive no ICAP revenue at all. This changes the expected outcome from $11/kW-mo. to $7/kW-mo. (averaging $14 and $0). This expected outcome is below the unit's cost and therefore it will not proceed with development.[41]

Under the NYISO's mitigation rules, this outcome is exacerbated by the application of the mitigation rules to an inappropriately broad category of resource types. For example, NYISO would subject a renewable resource to mitigation despite that fact that because of its development lead-time and public policy justification such a resource

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40 Paynter Aff. at 10:5-7 (citing PlaNYC 2014, http://www.nyc.gov/html/planyc/html/home/home.shtml (last visited Apr. 13, 2015)).

41 Cadwalader Aff. ¶ 35.

couldn't possibly raise price suppression concerns in the market. The initial focus should be to ensure the program is properly structured so that the universe of projects subject to mitigation encompasses only those with an intent and ability to suppress market prices.

The NYISO MMU has also repeatedly warned the NYISO that its rules could inappropriately mitigate otherwise economic projects.[42] As recently as January of this year, the NYISO MMU deemed inappropriate certain assumptions embedded in the test assessments upon which current BSM rules depend.[43] However, simply substituting better assumptions would not cure the flaws inherent in those tests.[44] Even with better assumption modeling, the analysis a developer conducts in considering whether to develop a project is likely very different from the elements that the NYISO depends upon in determining whether a project should be mitigated. The real threat of over-mitigation will continue to exist because so many of the assumptions simply are subjective in nature.

Moreover, the issues inherent in the faulty application of the BSM rules remain whatever the test assumptions. Simply put, applying the dubious mitigation tests to too

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[42] Potomac Economics Ltd., *2012 State of the Market Report for the New York ISO Markets* 24 (Apr. 2013), *available at* https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2012_SOM_Report_2013-04-17.pdf; *see also* Potomac Economics Ltd., *2013 State of the Market Report for the New York ISO Markets* xii (May 2014), *available at* https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2013_SOM_Report.pdf.

[43] Potomac Economics Ltd., *Assessment of the Buyer-Side Mitigation Exemption Tests For the Class Year 2012 Projects* 5 (Jan. 13, 2015), *available at* http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Class%20Year%202012/MMU%20Report%20on%20CY%202012%20BSM%20Tests.pdf.

[44] The Commission's recent decisions in *Astoria Generating Co. L.P. v. New York Independent System Operator, Inc.*, 151 FERC ¶ 61,043 (2015) ("*Astoria I*"), and *Astoria Generating Co., L.P. & TC Ravenswood, LLC v. New York Independent System Operator, Inc.*, 151 FERC ¶ 61,044 (2015) ("*Astoria II*"), do not therefore lessen the urgency of this Complaint. *Astoria I* made modifications to certain aspects of the NYISO's then-current BSM rules, but did not cure the inherent flaw in applying those rules to all projects. *Astoria II* addressed only the *application* of the tariff provisions effective prior to November 27, 2010 and expressly did not consider whether the tariff provisions themselves were just and reasonable. *Astoria II*, 151 FERC ¶ 61,044 at P 20. Additionally, as plants fueled by natural gas, these projects would be not be exempt from mitigation under the proposal made in this Complaint, but rather would be subject to BSM analysis.

broad a category of new projects inevitably ensures that projects undeserving of mitigation will be mitigated anyway. While the BSM rules' "original purpose . . . was to address buyer-side market power, i.e., the market power exhibited by entities seeking to lower capacity market prices for the capacity they buy,"[45] the NYISO's BSM rules apply regardless of whether the project developer is a net buyer of capacity. As the Commission recently noted, this "broader application has resulted in mitigation of certain resources that can derive no benefit from lower prices but, nonetheless, fail NYISO's mitigation exemption test as uneconomic resources."[46]

The risk of over-mitigation has adverse consequences beyond the immediate fate of any one project, because there will inevitably be "viable projects that never get pursued because of the threat of being denied capacity market payments."[47] While it is impossible to say with any assurance just how many projects have been scuttled due to the potential for over-mitigation, or how many investors have been deterred from participating in the New York markets, the fact that the NYISO's tariff creates this barrier to entry is reason enough to find the rules unjust and unreasonable.[48]

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[45] *Consolidated Edison*, 150 FERC ¶ 61,139 at P 2.

[46] *Id.*

[47] Paynter Aff. at 4:12-13; *see also* Cadwalader Aff. ¶ 35.

[48] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,157 at P 239 (2004), *clarified by* 111 FERC ¶ 61,367 (2005) (noting that "[e]ven the threat of over-mitigation may keep market participants out of the market.").

2. The Commission should revise the BSM rules to promote the proper functioning of the capacity market.

a. The BSM rules should only apply to an appropriately defined set of projects.

The Commission can correct the structural flaws in the BSM rules by limiting their application to only those types of projects that would likely be involved in any strategy to improperly attempt to depress capacity market prices. As noted above, the current BSM rules are applied to entrants that have no incentive or intent to suppress capacity prices, including even renewable resources and Special Case Resources such as demand response resources. They also are applied to resources that lack the ability to affect market clearing prices, such as repowerings that do not change the quantity of capacity available to the system. Any repowering of a facility does not raise price suppression concerns because that capacity is already recognized in the market. The decision to repower or retire a unit should rest with the unit's owner. For NYISO to drive that decision by unreasonably extending mitigation to a unit historically included in the market distorts the proper functioning of that market.

Rather than preventing the artificial suppression of ICAP market prices, the current BSM rules operate to protect incumbents from competition. Therefore, as discussed above, the current BSM rules are unjust and unreasonable and must be revised to avoid inappropriately mitigating new entrants (or existing facilities returning after a repowering) where there is no intent and ability to suppress capacity market prices. Specifically, the BSM rules should only apply to certain large (20 MW or greater) combined cycle or combustion turbine units powered by natural gas or oil.[49] Because these types of generating units can be built relatively quickly, they are the only resources that a net buyer of capacity would be likely to deploy in a strategy to suppress near term market prices.

Beyond those resources, and, to some extent even including them, uneconomic entry in the NYISO capacity markets, particularly in a densely populated locality such as New York City, is unlikely to be successful in suppressing prices for a number of reasons. First, the developer would have to obtain siting approval, a process that typically takes years to complete. The developer would have to bear the significant construction and interconnection costs incurred upon actually building the project. Even if, after clearing these hurdles, the new resource's entry actually did reduce the ICAP price, the developer is unlikely to reap long term price suppression benefits because the market response would tend to eliminate those benefits over time.

For example, as affiant Paynter describes, the Astoria Energy 2 power plant ("AE2"), which entered service July 1, 2011 at 575 MW, was subjected to mitigation in December 2012. While New York City's capacity price immediately decreased when AE2 entered service, these lower prices signaled a decreasing need for older, less efficient capacity. Within six months after July 1, 2011, a comparable amount of that capacity exited the market. As one would expect, the capacity prices promptly returned to a level consistent with the pricing in effect before AE2 entered the market.[50] The entry

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[49] The NYISO Tariff defines "Small Generating Facility" as one "no larger than 20 MW[.]" NYISO Open Access Transmission Tariff, Attachment Z – Small Generator Interconnection Process, § 32.5, Appendix 1. Due to their small size relative to the size of the market, such small facilities are unlikely to be effective tools for exercising buyer-side market power.

[50] Paynter Aff. at 17:12-21.

of AE2 did not, in fact, result in any sustained price suppression, and therefore could not represent a successful exercise of buyer-side market power. Instead, a comparable amount of older, less efficient, and higher emitting resources were no longer needed to satisfy capacity obligations. The owners of those resources either decided to shut down, or declined to spend the capital necessary to bring units back online after an outage—outcomes consistent with legitimate public policy goals. This is precisely the type of response expected of a well-functioning market, and which proponents of competitive markets have always extolled.

The Complainants recognize that intent to exercise buyer-side market power can be difficult to detect. However, it is not difficult to infer that certain types of capacity projects are not or could not be pursued with any intent to exercise buyer-side market power. Complainants assert that a just and reasonable mitigation program would recognize this reality. As the Commission has stated, subjecting projects without any incentive, intent, and ability to abuse buyer-side market power to mitigation "serves no competitive objective or market efficiency, regardless of whether they are judged uneconomic" under the current BSM rules.[51]

The types of projects unlikely to be utilized to exert market power include:

- **Renewable Resources:** Renewable resources are unlikely to be used for the abuse of buyer-side market power. Keeping in mind that the hypothetical developer seeking to abuse buyer-side market power must recover the resource's costs through lower market prices and that, compared to other available resources, such as gas turbines, renewables

[51] *Consolidated Edison*, 150 FERC ¶ 61,139 at P 46.

typically incur much higher development costs, renewable resources are a particularly inefficient tool for the exercise of buyer-side market power. Moreover, renewable resources usually operate intermittently, resulting in a lower than average contribution to meeting capacity requirements, making it even more unlikely that a buyer could use such a resource to drive down the capacity market price sufficient to recover the substantial development costs.[52] While it is highly unlikely such resources would be developed for the purpose of suppressing ICAP prices, they are essential to meeting other public policy goals and environmental initiatives. Such initiatives include the current proposed federal rules for controlling carbon dioxide, which identify renewable resources as a named strategy or "building block" as a means of achieving compliance. Therefore, a rule automatically subjecting such resources to review for potential mitigation review is unreasonable; in fact, these resources are not subject to such rules in other regional transmission organization ("RTO") capacity markets.[53]

- **Transmission Assets Coupled with UDRs:** Transmission lines are unlikely to serve as a resource that could support the exercise buyer-side market power. Transmission lines have long development times. Other market participants could simply take account of the transmission investment in adjusting the location and timing of their projects. The

[52] Paynter Aff. at 18:1-5.

[53] *See*, *e.g.*, PJM Interconnection, L.L.C., Open Access Transmission Tariff, Attachment DD, § 5.14(h)(2) (2015); ISO New England, Inc., Transmission, Markets, and Services Tariff § III.13.1.1.1.7 (2015).

market's rational and predictable response to transmission development renders it highly unlikely that those facilities could be used successfully to suppress market prices to an extent sufficient for the buyer to recover its costs.[54] Therefore, transmission facilities coupled with UDRs should not be subject to automatic review; in fact, they are not subject to such rules in other RTO capacity markets.[55]

- **Repowered Facilities:** Repowering of existing resources is unlikely to support the exercise of buyer-side market power for the simple reason that a repowering typically does not add new capacity. Repowerings provide important, desirable benefits, including fuel diversity and environmental improvements. Unless there is a net increase in the repowered unit's capacity, a repowering does not alter the amount of ICAP available in the zone.[56]
- **Nuclear Resources:** Nuclear resources also need not be subjected to mitigation review. The cost of a nuclear resource is so substantial as to render it virtually impossible to recover those costs through lower ICAP prices even if the resource successfully lowered ICAP prices. Thus, there

[54] Paynter Aff. at 18:5-9.

[55] *See*, *e.g.*, PJM Interconnection, L.L.C., Open Access Transmission Tariff, Attachment DD, § 5.14(h)(2).

[56] Paynter Aff. at 22:8-15. The Complainants acknowledge that the Commission recently directed NYISO to conduct a short stakeholder proves to determine whether resources under repowering agreements have the characteristics of new rather than existing resources, triggering a buyer-side market power evaluation and what mitigation measures need to be in place for those agreements. *IPPNY*, 150 FERC ¶ 61,214 at P 71. The Complainants are participating in that stakeholder process, but the outcome is uncertain at this point.

is no rational basis for imposing a risk of mitigation for these resources through the current BSM rules.

The Commission should acknowledge these realities and adopt a narrowly-tailored mitigation paradigm that applies only to combined cycle and combustion turbine units powered by natural gas or oil ("Mitigation Candidates"), because they are the resources that "have the shortest development time and thus are resources capable of suppressing capacity clearing prices."[57] Focusing properly drafted BSM rules on these resources would set the correct premise for a just and reasonable mitigation program. Even with this correction to the scope of BSM rules, however, the application of the rules to the remaining properly narrowed class of resources must also recognize the Competitive Entry, Self-Supply, and Reliability exemptions discussed below.

b. <u>The BSM rules should include appropriate pre-identified exemptions.</u>

As discussed above, the BSM rules should only apply to Mitigation Candidates.[58] However, even Mitigation Candidates should not be presumed to represent instances of buyer-side market power. The mitigation rules must include certain pre-identified exemptions to avoid the risk of over-mitigation.

[57] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 166 (approving PJM Interconnection, LLC's proposal to apply its Minimum Offer Price Rule to only those resources that are most likely to be associated with offers that raise price suppression concerns).

[58] For purposes of this Complaint, the types of generators that the Complainants believe should be subject to the BSM rules are referred to as the "Mitigation Candidates."

i. The BSM rules should include the Competitive Entry Exemption.

The Commission recently approved the inclusion of a CEE in the BSM rules.[59] Exempting entrants lacking market power or atypical subsidies from the BSM rules would encourage merchant facilities to enter the market, increasing available supply options and ultimately benefitting New York ratepayers. Even after the re-focusing the rules on the appropriate Mitigation Candidates, the Commission's rationale for recognizing the CEE remains valid, and it should be retained as a component of the BSM rules.

The CEE, however, should not be left standing alone among BSM rules that otherwise remain unchanged. Absent the restructuring of those rules, a solitary CEE will exacerbate the adverse impact those rules already have on the market because the exempted CEE projects will be reflected in the NYISO market forecasting tests used in applying market mitigation. Because the construction of CEE projects can await a time when market rates become favorable, their presence in the tests may be speculative and, if not built or if delayed, will drive the resulting forecasts further away from an accurate depiction of future circumstances. As a result, any project without an exemption attempting to pass the economic tests will find the task even more difficult once CEE projects are included. Therefore, it is imperative that the BSM rules be revised to be made applicable only to that limited category of gas and oil fired projects of more than 20 MW where market price suppression is actually feasible if in the hands of a buyer with an

[59] *Consolidated Edison*, 150 FERC ¶ 61,139.

intent to depress prices. That way a CEE and other appropriate exemptions compliment the BSM program to ensure it can achieve its intended effect and only its intended effect.

ii. The BSM rules should include an SSE.

The BSM rules should reflect an SSE that permits a load serving entity to build or contract for capacity resources, within specific limits, in order to meet its own reasonably anticipated ICAP obligations. The SSE would permit load serving entities ("LSE") to make their own decisions on the purchase of the capacity that best meets their needs. LSEs would also be permitted to hedge their exposure to future ICAP obligations based on their reasonable expectations for the future, rather than on the expectations the NYISO sets through its flawed BSM rules.

An appropriately designed SSE should accommodate reasonable variations in an LSE's net short or net long position, as it is unlikely that an LSE will be able to perfectly match its capacity with its ICAP obligations for several reasons. First, an LSE's ICAP obligation depends on numerous factors beyond the LSE's control, such as the ICAP requirement set by the NYISO and the New York State Reliability Council, the amount of surplus ICAP sold in the Spot Market Auction, and the forecasted peak load as established by the NYISO, among other things.[60] Second, the amount of Unforced Capacity that a particular resource will contribute to an LSE's ICAP obligation cannot be perfectly known in advance and depends on the results of capacity production testing as well as that resource's history of forced outages.[61] Third, to achieve economies of scale, an LSE would tend to develop new resources in tranches of capacity larger than its

[60] Cadwalader Aff. ¶ 41.

[61] *Id.*

immediate forecast of the amount it needs. Consequently, the LSE frequently has either less ICAP than that exactly needed to meet its obligations (and therefore be in a net short position) or has more ICAP than exactly needed to meet its obligations (and therefore be in a net long position).[62]

Given this uncertainty, the ability of an LSE to suppress market prices through uneconomic entry is limited. Any concerns regarding uneconomic, manipulative entry by LSEs can be fully addressed through net short and net long limits on the SSE exemption.

Hypothetically, an LSE with a large net short position, one significantly larger than the resource it proposes to develop, could have an incentive to unfairly subsidize the entry of an uneconomic resource. However, this unfair subsidization only makes economic sense for the LSE if its net short position, even after the addition of the new resource, remains so large that the LSE can recover the subsidy it paid for the new resource by reducing the market-clearing price the LSE pays on its remaining ICAP obligation. Establishing a maximum net short position for LSEs seeking to develop a resource under the SSE can ensure that the SSE is not used in this anticompetitive manner.[63]

Another potential concern with SSE is that an LSE could use the SSE to develop a new resource that is uneconomic, with the intent to recoup the cost of the uneconomic resource not merely through its own ICAP purchases, but from the ICAP purchases of <u>all</u> LSEs that might benefit from the lower market clearing price—although it is notable that there is no existing mechanism that would permit such an LSE to recoup the savings

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[62] *Id.*

[63] *Id.* ¶ 42.

accruing to other market participants. A net long threshold and an historical service standard would alleviate this potential concern. By limiting the SSE to LSEs whose ICAP portfolios are consistent with reasonably anticipated levels of their future ICAP obligations, the net long threshold prevents SSE from being used in an anticompetitive manner.[64]

Affiant Cadwalader includes an analysis of the net long and net short thresholds he recommends be included in the BSM rules regarding the SSE. The tables below illustrate the net short and long thresholds for the relevant MCZs that Mr. Cadwalader recommends as a result of that analysis, which are more fully explained in his affidavit:

1. Net Short Thresholds for NYC and G-J

Maximum Net Short Thresholds for Entry in NYC
(For LSEs That Serve Load in NYC But Not in the LHV)

LSE's Share of NYC and G-J Loads	Max. Net Short Threshold as % of LSE's NYC and G-J UCAP Obligations
5%	5.0%
10%	5.5%
15%	5.5%
20%	5.5%
30%	5.5%

Maximum Net Short Thresholds for Entry in NYC
(For LSEs That Serve Load in NYC and in the LHV)

LSE's Share of NYC Load	Max. Net Short Threshold as % of LSE's NYC UCAP Obligation
5%	4.5%
10%	5.0%
15%	5.0%
20%	5.0%
30%	5.0%

64 *Id.*

Maximum Net Short Thresholds for Entry in the LHV (G-J)

LSE's Share of G-J Load	Max. Net Short Threshold as % of LSE's G-J UCAP Obligation
5%	12.5%
10%	8.0%
15%	7.0%
20%	6.0%
30%	5.5%

2. Net Long Thresholds for NYC and G-J

Maximum Net Long Threshold for Entry in NYC
(For LSEs That Serve Load in NYC But Not in the LHV)

LSE's Share of NYC Load	LSE's NYC UCAP Obligation (MW)	Max. Net Long Threshold (MW)
5%	517	78
10%	1,035	155
15%	1,552	200
20%	2,070	200
30%	3,104	200

Maximum Net Long Threshold for Entry in NYC
(For LSEs That Serve Load in NYC and in the LHV)

	G-J		NYC	
LSE's Share of NYC or G-J Load	LSE's UCAP Obligation (MW)	Max. Net Long Threshold (MW)	LSE's UCAP Obligation (MW)	Max. Net Long Threshold (MW)
5%	726	109	517	78
10%	1,452	218	1,035	155
15%	2,178	250	1,552	200
20%	2,904	250	2,070	200
30%	4,356	250	3,104	200

Maximum Net Long Threshold for Entry in the LHV

LSE's Share of G-J Load	LSE's G-J UCAP Obligation (MW)	Max. Net Long Threshold (MW)
5%	726	109
10%	1,452	218
15%	2,178	250
20%	2,904	250
30%	4,356	250

Mitigation is more likely to cause harm when it is applied to entities who have no incentive to act in an anticompetitive manner, and when it is difficult to ascertain what offers an entity would submit if it were acting in a competitive manner. A well-designed SSE can permit LSEs to hedge their positions through self-supply while addressing some of these concerns. Entities that self-supply the ICAP needed to meet their ICAP obligations should not have an incentive to suppress prices, as they will not have a significant net short position. The SSE would permit such entities to be exempted from unnecessary mitigation, thereby reducing the harm that such mitigation may cause, while also containing safeguards that would prevent LSEs from suppressing those prices significantly below competitive levels.

iii. The BSM rules should include a Reliability Exemption.

The BSM Rules should also include a Reliability Exemption for a new gas- or oil-fired generating unit that is being developed as a solution to a reliability need identified by the NYISO under its reliability planning tariff, Attachment Y to the NYISO Open Access Transmission Tariff. While the tariff's primary function is to determine cost recovery for transmission solutions, the process provides for the designation of a generation solution instead of a transmission proposal. A gas- or oil-fired unit that is developed in response to the NYISO's solicitation and evaluation of solutions to reliability needs does not implicate any suspect motive to manipulate the market. Subjecting such a project to the risk of mitigation would deter developers from offering generation solutions in the planning process and potentially deprive ratepayers of cost-effective alternatives. Thus, the BSM rules should exempt Mitigation Candidates that are solutions to reliability needs that the NYISO identifies in its Attachment Y process.

3. The Commission has approved similar BSM rules.

As described in detail above, the current BSM rules are unjust and unreasonable and the proposed changes are necessary to result in a just and reasonable market structure. The Commission has approved similar BSM rules in the capacity markets administered by other RTOs.

For example, until recently, PJM Interconnection, LLC ("PJM") applied its Minimum Offer Price Rule ("MOPR") mitigation measures to all resource types, including gas-fired, coal, nuclear, or renewable. In supporting its request to apply MOPR to only a limited set of resources, PJM argued that MOPR should apply only to those resources that are most likely associated with offers that raise price suppression concerns and that an overbroad mitigation rule causes uncertainty for project developers that adversely affects the market.

The Commission agreed and approved PJM's request to apply MOPR only to gas-fired combustion turbines, combined-cycle, and integrated gasification combined-cycle resources.[65] The Commission determined that "[c]ombustion turbine and combined cycle resources have the shortest development time and thus are resources capable of suppressing capacity clearing prices. Moreover, given these units' low construction costs, they may be the most cost effective resources with which to suppress market prices."[66] The Commission also approved a self-supply exemption, finding that,

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[65] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 166.

[66] *Id.* at P 167.

"providing exemptions for resources properly designated as self-supply when they meet suitable net-short and net-long thresholds is reasonable."[67]

The Commission should make similar findings here. Complainants fashioned their proposed revisions to the NYISO BSM rules consistent with the mitigation principles the Commission endorsed for PJM. The NYISO BSM rules should apply to those resources that are most likely to be associated with offers that raise price suppression concerns and should include a self-supply and reliability exemption as well as the already approved CEE.

C. <u>The Commission should act promptly.</u>

The Commission should move promptly to implement the comprehensive approach to proper application of the NYISO's BSM rules proposed in this Complaint, instead of continuing to approach BSM revisions piecemeal. Several features of the BSM rules are already under consideration in connection with a repowering.[68] Moreover, the Commission, in finding existing BSM rules must be interpreted as fully applying to the Special Case Resources that are a feature of New York's demand response programs, specifically opened that feature of the rules as a topic for consideration in a complaint.[69] Action on this Complaint would resolve these issues and avoid the undue interference with the legitimate state demand resource programs that the Commission cautioned against, by restricting the ambit of the BSM rules to the gas- and oil-fired generation units that might actually warrant buyer market power scrutiny. Promptly modifying the

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[67] *Id.* at P 108. The Commission also approved a competitive entry exemption. *See id.* at P 53. The Commission has already approved the CEE for the NYISO BSM rules.

[68] *IPPNY*, 150 FERC ¶ 61,214 at P 71.

[69] *N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,208 at P 30.

BSM rules as proposed in this Complaint also would assist NYISO in effectively and efficiently revising its BSM rules to work as intended as a remedy for buyer-side market power without distorting markets or improperly favoring incumbents to the detriment of consumers.

Engaging in the NYISO stakeholder process as a means for resolving these issues, however, will result in significant delay because it is overburdened. BSM issues also do not lend themselves to efficient resolution in the stakeholder process, as the road to adoption of CEE amply demonstrates. The Complainants should not be compelled to engage in what might become an unduly protracted stakeholder process while the unjust and unreasonable BSM rules that threaten effective market operations and obstruct pressing public policy goals remain in place.

Therefore, the Commission should direct the NYISO to make the changes to the BSM rules proposed in this Complaint in a tariff filing that would promptly correct the currently unjust and reasonable BSM rules before they further distort markets. The NYISO could be directed to make such a filing within 90 days of the order's issuance after consultation with interested stakeholders,[70] thereby arranging for their input without risking the delay likely to accompany the voting and other procedures of a full stakeholder process.

Alternatively, should the Commission determine additional procedures are needed before all of the issues can be resolved, it could set the matter for hearing and provide for the appointment of a settlement judge. That supervision should ensure the more prompt

[70] A similar process was followed in *IPPNY*, 150 FERC ¶ 61,214.

and efficient consideration of the Commission's concerns than could be accomplished in the overburdened stakeholder process.

VII. ADDITIONAL REQUIREMENTS OF RULE 206

Pursuant to Rule 206, Complainants sets forth below the following information that is not provided elsewhere in the Complaint:

Rule 206(b)(4)(5): Financial Impact and Nonfinancial Impacts on Complainants

Complainant is unable to accurately quantify the aggregate dollar impact of the Respondent's inactions. However, as discussed herein, there is a harm of not having a fully competitive market if the buyer-side mitigation measures are not amended in the manner requested herein.

Rule 206(b)(6): Related Proceedings

Complainant is aware of two other proceedings before the Commission related to the NYISO's mitigation. Specifically, on December 4, 2014, Consolidated Edison Company of New York, Inc. ("Consolidated Edison"), New York State Electric & Gas Corp., Orange & Rockland Utilities, Inc., Rochester Gas and Electric Corp., and Central Hudson Gas & Electric Corp. filed a complaint in Docket No. EL15-26-000 against the NYISO seeking modifications of NYISO's Market Services Tariff to add a CEE from existing mitigation measures in NYISO's capacity market. Also, On December 16, 2014, TDI USA Holdings Corp. ("TDI") submitted a complaint in Docket No. EL15-33-000 against the NYISO seeking a case-specific exemption from the mitigation measures for TDI's Champlain Hudson Power Express Project. On February 26, 2015, the

Commission granted Consolidated Edison's complaint and ordered the NYISO to make a filing establishing a CEE and denied TDI's complaint as moot.[71]

In addition to the pending complaint proceedings identified above, there are other proceedings that are pending or are within the rehearing period that raise other issues concerning the buyer-side mitigations measures. These proceedings are listed below as well as the United States Court of Appeals D.C. Circuit ("Court of Appeals") proceedings that are held in abeyance pending a final Commission decision.

At the Commission:

- *New York Independent System Operator, Inc.* Docket No. ER12-2414
- *New York Independent System Operator, Inc.* Docket No. ER10-2371
- *Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc.* Docket No. EL13-62
- *Hudson Transmission Partners, LLC v. New York Independent System Operator, Inc.* Docket No. EL12-98
- *Astoria Generating Co., L.P. v. New York Independent System Operator, Inc.* Docket No. EL11-50
- *Astoria Generating Co., L.P. v. New York Independent System Operator, Inc.* Docket No. EL11-42
- *New York Independent System Operator, Inc.* Docket No. EL07-39
- *Dunkirk Power, LLC* Docket No. ER12-2237
- *Cayuga Operating Co., LLC* Docket No. ER13-405
- *Niagara Mohawk Power Corp.* Docket No. ER14-543

At the Court of Appeals:

[71] Rehearings of the Commission's order were filed on March 30, 2015.

- *New York State Department of Public Service v.*
  Federal Energy Regulatory Commission Case No. 08-1366

- *Consolidated Edison Co. of New York, Inc. v.*
  Federal Energy Regulatory Commission Case No. 08-1368

- *Astoria Generating Co., L.P. v.*
  Federal Energy Regulatory Commission Case No. 08-1369

- *New York Power Authority v.*
  Federal Energy Regulatory Commission Case No. 08-1370

Rule 206(b)(7): Specific Relief Requested

The Complainants request that the Commission make the following findings:

1. That the NYISO BSM rules are unjust and unreasonable because they prevent the ICAP market from functioning properly.
2. That the BSM rules should apply to only a limited subset of generation facilities; namely: new gas- or oil-fired simple and combined cycle units.
3. That the re-focused BSM rules should include, in addition to the CEE, an SSE and a reliability exemption.
4. That the NYISO be ordered to make a compliance filing revising its Market Services Tariff consistent with the Commission's findings upon this Complaint, or, in the alternative, the Commission set the matter for hearing while providing for a settlement process.

Rule 206(b)(8): Documents that Support the Complaint

Documents supporting the Complaint include:

- Exhibit A – Affidavit of Thomas S. Paynter

- Exhibit B – Affidavit of Michael D. Cadwalader

- Exhibit C – Affidavit of Adam Evans

Rule 206(b)(10): Notice of Complaint

A form of notice suitable for publication in the *Federal Register* is attached to this Complaint.

Rule 206(c): Service

A copy of this Complaint has been served on the following party via e-mail:

Robert Fernandez
General Counsel
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, New York 12144

VIII. CONCLUSION AND RELIEF REQUESTED

For the reasons set forth herein, the Complainant respectfully requests that the Commission order the NYISO to make a compliance filing within 90 days to amend the Market Services Tariff and the mitigation measures in the manner proposed in this Complaint.

Respectfully submitted,

/s/ Gary D. Bachman

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Attorneys for Complainants

Dated: May 8, 2015

Attachment 1

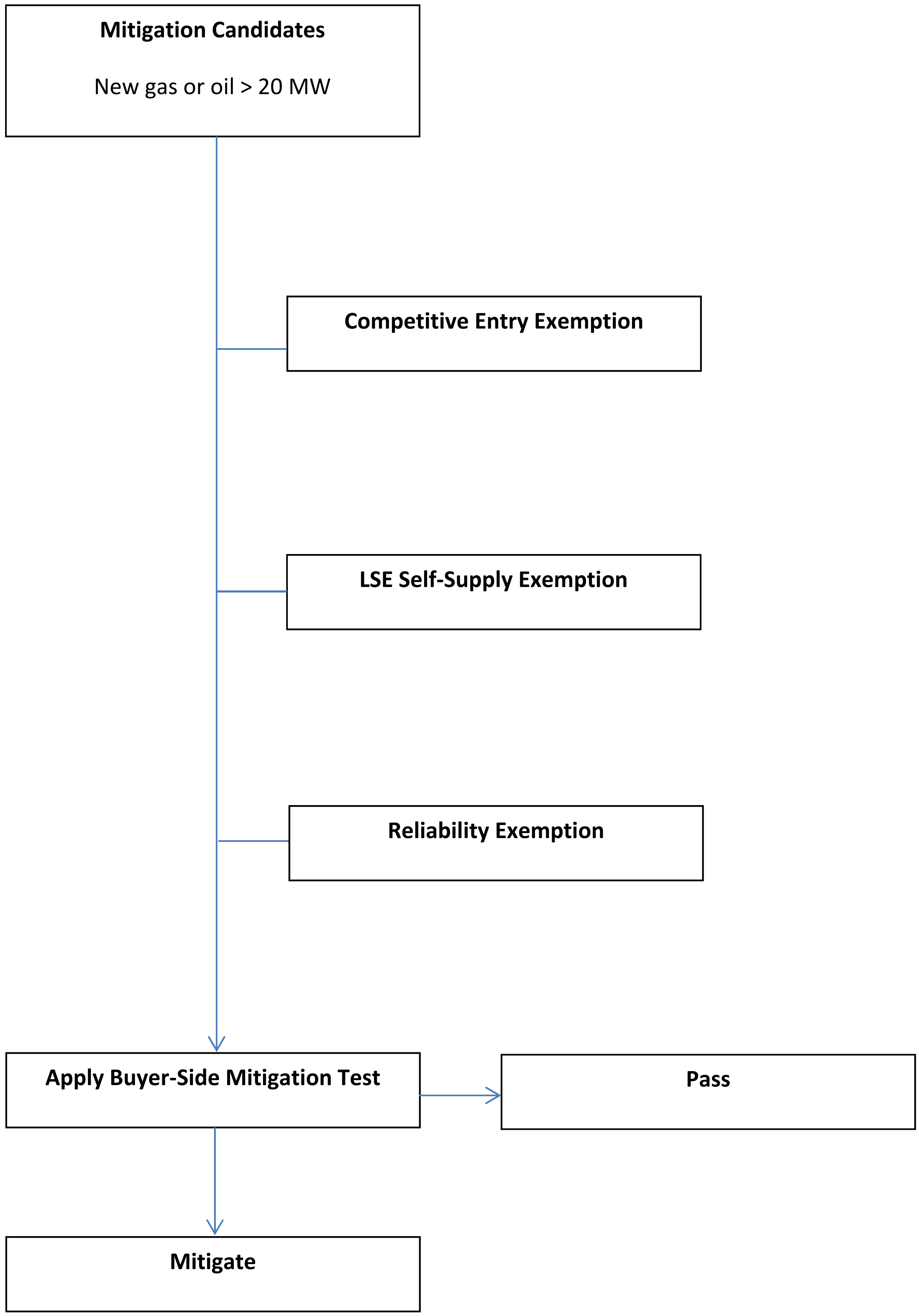
Mitigation Candidates
New gas or oil > 20 MW
Competitive Entry Exemption
LSE Self-Supply Exemption
Reliability Exemption
Apply Buyer-Side Mitigation Test
Pass
Mitigate

Exhibit A

Affidavit of Thomas S. Paynter

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NEW YORK PUBLIC SERVICE COMMISSION AND NEW YORK POWER AUTHORITY,	)	
COMPLAINANTS,	)	
V.	)	**DOCKET NO. EL15-___-000**
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.,	)	
RESPONDENT.	)	

AFFIDAVIT OF THOMAS S. PAYNTER
ON BEHALF OF THE COMPLAINANTS

I, Thomas S. Paynter, being duly sworn, depose and say:

I. Qualifications and Purpose

Please state your name, occupation, and business address?

My name is Thomas S. Paynter. I am employed by the New York State Department of Public Service ("NYSDPS") as Supervisor of Regulatory Economics in the Office of Regulatory Economics. My business address is Three Empire State Plaza, Albany, New York, 12223-1350.

Please describe your education and professional experience?

I received a Ph.D. in Economics from the University of California at Berkley, with fields in econometrics and labor economics. I have a B.A. in Physical Science and in Economics, also from the University of California at Berkeley.

From 1983 to 1986, I was an Assistant Professor of Economics at Northern Illinois University, where I taught graduate and undergraduate courses in economic theory. From 1986 to 1990, I was employed by the Illinois Commerce Commission as a Senior Economic Analyst in the Policy Analysis and Research Division and served as a member of the Electricity Subcommittee of the National Association of Regulatory Utility Commissioners. I also authored an article concerning coordination and efficient pricing for independent power producers, "Coordinating the Competitors," published by The Electricity Journal in November 1990. I joined the NYSDPS in November of 1990.

What are your current job responsibilities?

My current responsibilities include analyzing competitive issues, efficient pricing, marginal costs, and regulatory policies. I am a member of a staff team responsible for analyzing and commenting upon the pricing rules of the New York Independent System Operator ("NYISO"), which operates the New York transmission system. I participate in NYISO meetings, including the Business Issues Committee, the Market Issues Working Group, Installed Capacity Working Group, and the Electric System Planning Working Group. I have been the NYSDPS staff leader in the design of New York's capacity markets since the start-up of the NYISO. I am the author of the sloped "demand curve" that was approved for use in the NYISO capacity markets in 2003, and constitutes a key component in a well-functioning capacity market. Utilization of the sloped demand curve has since become a "best practice" approved for use in PJM Interconnection and in ISO New England.

Have you previously provided testimony on behalf of the NYSDPS?

Yes. I have testified in numerous rate cases and other proceedings before the New York Public Service Commission ("NYPSC") and before the New York State Board on Electric Generation Siting and the Environment ("Siting Board"), on economic topics including rate design, cost/benefit analysis, transmission congestion, and competitive markets. I have also provided testimony in proceedings before the Federal Energy Regulatory Commission ("Commission") on capacity market design, market power, and market power mitigation.

Are you a member of any professional organizations in your field?

Yes. I am a member of the American Economic Association and the Society for Neuroeconomics.

What is the purpose of your testimony in this proceeding?

The purpose of my affidavit is to support the NYPSC and New York Power Authority's ("NYPA") (collectively, the "Complainants") Section 206 complaint under the Federal Power Act regarding the need to change the NYISO Market Administration and Control Area Services Tariff ("MST") in a manner that results in buyer-side mitigation ("BSM") rules that are just and reasonable and not unduly discriminatory or preferential. In my testimony I briefly describe the New York installed capacity markets and discuss their relationship to New York's public policies. Next, I describe the theory of buyer-side market power and its application to New York's capacity markets. Then I explain why the NYISO's current BSM rules are inappropriately broad. Finally, I offer recommendations for a more appropriate, narrowly-tailored BSM rule.

Can you briefly summarize your testimony?

Under New York Public Service Law, and consistent with the Federal Power Act, the NYPSC and the Siting Board must balance economic goals with environmental and other public policy goals. As a result, the NYPSC and the Siting Board may site, and approve cost recovery for, resources that best serve all of these goals—which will not necessarily be resources with the lowest cost per megawatt. The NYISO's BSM rules interfere with this mandate, by threatening to label such resources as "uneconomic" and withhold capacity market payments from them, based on implausible and unproven claims of "buyer-side market power."

In fact, rather than creating any sustained price suppression, new entry into the market is more likely to simply displace existing, less efficient capacity; such displacement is a normal market outcome and is not by itself evidence of the inappropriate exercise of "buyer-side market power." The current BSM rules ignore this simple economic principle and apply the mitigation screens to every new project entering the market in a mitigated capacity zone, regardless of any intent to exercise market power.

The mitigation screens themselves, including the base assumptions underlying those screens, are subjective and contentious, and threaten to result in inefficient over-mitigation, as recently acknowledged by the NYISO Independent Market Monitor ("IMM"). More troubling, however, are the viable projects that never get pursued because of the risk of over-mitigation and the threat of being denied capacity market payments.

The Commission has recently recognized these concerns in approving a Competitive Entry Exemption ("CEE"), for "purely merchant" projects that are able to obtain financing without resort to any contracts with buyers. However, many potentially valuable projects are unable to obtain financing on reasonable terms without contracts with buyers. Moreover, the State of New York and its political subdivisions have legitimate public policy interests, which may require support for certain projects, such as renewable resources or repowering to reduce local emissions. The current BSM rules, even with the CEE, are so broad as to interfere with these legitimate needs. The BSM rules should therefore be narrowly focused to address only those new entrants (certain gas-fired generators) that might be proposed with the intent to exert buyer-side market power, rather than assuming every new entrant is "guilty until proven innocent."

II. The New York Capacity Markets

Can you briefly describe the role of Installed Capacity ("ICAP") in ensuring the reliability of New York's electric system?

ICAP refers to the maximum capability to provide electrical power (either by specific generating units or transmission of off-system generation), or the ability to reduce demand at the direction of the NYISO, as measured in megawatts ("MW"). In order to reliably serve peak load, the NYISO requires a minimum amount of ICAP, equal to forecasted system peak load plus a small reserve margin to account for, among other factors, extreme weather and random outages of resources; this is referred to as "resource adequacy." The statewide minimum reserve requirement is established annually by the New York State Reliability Council.

While the ICAP market is an important component in reliably serving, it is not the only component of reliability. Besides resource adequacy, the NYISO also considers other reliability measures, such as transmission security (the ability to withstand the outage of a major transmission line), voltage limits (ensuring system voltages are within reasonable bounds at all locations) and stability (ensuring transient disturbances are damped). The NYISO evaluates the reliability of New York's electric system through its Comprehensive Reliability Planning Process ("CRPP"). In addition, the local transmission owners evaluate reliability on the local transmission systems. Resources may be developed to address any one or more of the myriad reliability issues, not just resource adequacy.

Does resource adequacy take into account limits on the transmission system?

Yes, resource adequacy takes into account certain transmission limits. For example, New York City is a "load pocket": it does not have sufficient transmission import capability to meet its peak load without relying on local generation resources. The NYISO therefore calculates the Locational Minimum Installed Capacity Requirements ("LCR") for the New York City locality to determine how much ICAP must be electrically located within the New York City locality itself. For the 2014-2015 capability year, NYISO calculated the LCR for the New York City locality to be 85 percent of its peak load, or approximately 10,016 MW. Thus, NYISO's rules require that approximately 10,000 MW of ICAP be physically located within the New York City locality (or directly connected electrically) to meet resource adequacy standards. Other load pockets include Long Island and the "G-J Locality," which covers the Lower Hudson Valley and New York City; these localities have their own LCRs.

How does the NYISO ensure sufficient capacity to meet resource adequacy requirements?

The NYISO obligates all Load Serving Entities ("LSEs") to procure sufficient capacity to serve their own customers' forecasted peak loads, including the required reserve margin. Deficient LSEs are required to procure the remainder of their capacity obligations from the NYISO's spot auctions, held just prior to the beginning of each month. Importantly, the NYISO specifies the bids of each LSE in the spot auctions, via a formulaic "demand curve" specified in the NYISO tariff, rather than allowing LSEs to enter their own bids.

Why does the tariff specify the LSEs' capacity bids, rather than allowing LSEs to set their own bids?

If LSEs were simply allowed to set their own bids, they would likely procure too little ICAP to ensure reliability. The State of New York allows retail access, meaning LSEs must compete for customers, which may be scattered across the state. As a result, the NYISO cannot generally provide more reliability to one LSE than to its competitors, regardless of their respective levels of ICAP purchases. Because of this, each LSE has a natural incentive to purchase less ICAP than its competitors and "lean" on the system for reliability; this is known as the "free rider" effect. Thus, allowing the LSEs to set their own bids could result in $0 bids for ICAP, regardless of its value to the system. In short, while ICAP is important to system reliability, it is more akin to a "public good" which, like national defense, typically requires government intervention to provide adequately. The poor price signals resulting from this market design became evident once the NYISO introduced capacity market auctions in May 2000.

To address the free rider effect, the NYISO tariff originally imposed a very high "deficiency charge" on LSEs that had not procured sufficient ICAP. However, this led to "boom and bust" prices, in which ICAP prices were near $0 for even small levels of excess supply, but could spike unpredictably due to a small change in supply. The natural tendency for market participants to hedge these unpredictable ICAP prices (via long-term contracts between buyers and sellers) were undermined by the free rider effect. To improve the predictability of the ICAP prices, I proposed to replace the tariff-based deficiency charge with a sloped "demand curve." Under this approach, the LSE bids in the spot auctions are set by the NYISO tariff via the demand curves. These provide a (sloped) floor on LSE bids, so that a reduction in supply (tighter market) will slide up the demand curve and result in predictably higher market-clearing prices, signaling an increased value to capacity. Conversely, an increase in supply will result in predictably lower market-clearing prices, signaling a decreased value to capacity and encouraging exit of resources that are no longer profitable and are not needed for resource adequacy. For a level of supply slightly in excess of the minimum requirement, the LSE bids are set at the levelized carrying cost to construct and operate a simple cycle gas turbine ("GT"), net of the energy and ancillary services revenues that would be realized by the resource. The sloped demand curve was negotiated among NYISO market participants, resulting in a successful vote by the NYISO's Management Committee in 2002 and a section 205 filing by the NYISO, which was approved by the Commission in 2003.

Why does the NYISO base the LSE bids on the cost of a new gas turbine?

A new gas-fired turbine is one possible source of capacity, which is relatively quick and easy to site and build. The cost of a gas-fired turbine thus provides a natural cap on the value of capacity: If additional capacity is needed quickly for resource adequacy, a natural choice would be to site and build gas-fired turbines to meet that need.

Why does the NYISO allow LSE bids to go to $0 when there is ample supply?

As in markets for other goods and services, the marginal value of ICAP generally decreases as the amount increases. If capacity is far in excess of minimum requirements, additional ICAP provides little if any increase in reliability. In that case, the demand curve appropriately allows LSE bids to fall to $0, which in turn allows ICAP market prices to fall, potentially to $0. If existing suppliers are making sufficient revenues in the energy and ancillary services markets, they will continue to operate, and will continue to supply ICAP (since there is almost no incremental cost for an operating plant to also supply ICAP). However, if a particular supplier is inefficient and cannot make sufficient revenues in the energy and ancillary services markets, it will have an incentive to exit the market when ICAP prices are at low levels. This is desirable, because it avoids wasting resources keeping unneeded plants in operation, and because it frees up space on the transmission system, which makes room for the interconnection of new, more efficient, lower emission resources.

III. Public Policies Impacting New York's Capacity Markets

What obligations do utilities have under New York law?

The New York Public Service Law obligates utilities to provide safe and adequate service at just and reasonable rates, while preserving environmental values and conserving natural resources. The NYPSC has encouraged competitive markets, where feasible, as one means to satisfy the requirement that rates for energy services are just and reasonable. In the 1990s, the NYPSC negotiated with the state's utilities to divest generation resources and establish competitive wholesale energy markets, acting as facilitator for the NYISO, as the successor to the New York Power Pool. Since then, the NYPSC has continued to work with the state's utilities to promote wholesale and retail markets for energy and capacity. For example, the NYPSC has employed auctions to meet renewable portfolio standards at least cost.

What other factors must be considered under the New York Public Service Law?

The New York Public Service Law requires that electric resources meet a variety of public policy needs. These include maintaining local reliability, minimizing local environmental emissions and providing fuel diversity (an important factor in long-term reliability). Many of these other factors constitute "externalities" (i.e., factors that impact parties other than the individual buyer and seller), which may not be priced directly into the markets, but which are nevertheless important to the public interest. For example, local reliability needs tend to be so specific to a geographic area that only one or a few resources can satisfy those needs; under such case-specific circumstances, it is rarely possible to create workably competitive markets. Instead, resources must be evaluated on an individual basis. For the siting of new transmission or generation resources, all of these factors must be considered by the NYPSC or the Siting Board.

Does New York City have any public policies regarding its electric system?

Yes. As mentioned above, the NYISO requires over 10,000 MW of installed capacity to be physically located within the New York City locality or directly connected electrically. All power plants produce local air and water emissions and noise, which are of particular concern in densely populated localities such as New York City. The PlaNYC effort by New York City has several goals related to providing cleaner, more reliable, and affordable energy to the residents of New York City, including replacing or repowering the most inefficient in-city power plants. But as the PlaNYC 2014 Progress Report notes, this requires changing the wholesale market design so that it "does not discourage sensible repowering and new generation projects." Similarly, the study "A Master Electrical Transmission Plan for New York City," prepared by CRA International in 2009, noted (at p. 23) that "[t]here are public policy objectives such as meeting environmental goals, stimulating economic activity, and promoting new technologies which may not (or can not) be fully captured when projects are evaluated only by economic metrics." The City's policies include reducing local emissions and promoting noise abatement through increasing transmission capability into the City. Transmission lines coupled with unforced deliverability rights ("UDRs") allow generators to be directly connected electrically into the City; other transmission lines (without UDRs) may still reduce the LCRs for the zone, permitting the shutdown of less efficient, higher polluting sources of generation within the City. However, depending on the size of the retired unit and the amount of capacity in the region after its retirement, to maintain reliability it may be necessary for new generating sources and/or transmission capability to enter the market before the old plants can be shut down.

Has New York City taken actions to implement its policies?

Yes. The City, along with other governmental entities (Metropolitan Transportation Authority, Port Authority of the State of New York and New Jersey, New York City Housing Authority and New York State Office of General Services) committed to purchase the output of the Astoria Energy II project, a state-of-the art 575 MW combined cycle gas-fired plant located in Astoria, Queens (within the City), which supported the developer's ability to obtain financing.

The City also supported the siting of the Champlain Hudson Power Express Project ("CHPE") HVDC transmission line, which is intended to import 1000 MW of energy, primarily from hydroelectric and wind resources, from Canada into Astoria, Queens, at an estimated cost of over $2 billion. However, the City has indicated that it does not intend to help finance CHPE; instead, the project developers ("TDI") are looking to owners of generation resources in Canada who are trying to increase their market options for their energy and capacity sales.

Is it appropriate for New York City to take such actions to implement its public policies?

Yes. It is commonplace in markets for buyers to pay for products based on quality, not just on quantity. Put another way, buyers value the complete set of attributes provided by a given product and do not focus only on one to the exclusion of all others. In the case of power plants, it is entirely rational and appropriate for buyers to consider not just the contribution to meeting resource adequacy requirements of a generation facility but also its efficiency, operational reliability and environmental profile when deciding what resources should be procured. Thus, state and local governments may act as the agents/buyers for their constituents. The New York City government, for example, may choose to encourage the siting of a higher quality power plant—considering reliability, impact on the environment, noise, etc.—in order to achieve its public policy goals. And the State of New York must consider how to meet the CO2 standards under EPA's proposed section 111(d) rules.

Do public policy goals impact the ICAP market?

Yes. It is important to recognize that public policy goals and enactments can and do drive market clearing prices up as well as down. For example, the New York State Department of Environmental Conservation required the retirement of the 890 MW Poletti 1 plant in Astoria, Queens, for environmental reasons, by February 2010. This action tightened the NYC capacity market and consequently produced a sharp increase in the statewide and NYC ICAP market prices. At other times, public policy goals may reduce ICAP prices, as in the efforts to promote energy efficiency and the use of demand response, which tend to reduce peak loads and thereby may reduce ICAP market prices in the short term. An efficient spot market for capacity will allow prices to reflect the short-term changes in supply, whether up or down, and thereby signal an efficient market response.

Have the Courts weighed in on this point?

Yes. The US Court of Appeals for the Third Circuit recently stated the following:

> The states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility. Or states may elect to build no electric generation facilities at all. … The states' regulatory choices accumulate into the available supply transacted through the interstate market. The Federal Power Act grants FERC exclusive control over whether interstate rates are "just and reasonable," but FERC's authority over interstate rates does not carry with it exclusive control over any and every force that influences interstate rates. Unless and until Congress determines otherwise, the states maintain a regulatory role in the nation's electric energy markets.

PPL Energy Plus v. Solomon, 766 F.3d 241, 255 (3d Cir. 2014).

IV. Buyer-Side Market Power

What is buyer-side market power?

The United States Department of Justice ("DOJ") defines market power as the "ability of one or more firms profitably to maintain prices above competitive levels for a significant period of time" and states that market power also "encompasses the ability of a single buyer or group of buyers to depress the price paid for a product to a level that is below the competitive price." Justice Dept. Merger Guidelines, June 14, 1984, section 1 (p. S-1). This latter concept is commonly referred to as buyer-side market power. Thus a large buyer could withhold demand from the market, buying less of a product in order to lower the product's market price. While the buyer would value an additional quantity higher than the market clearing price, it would refuse to raise its bid to purchase that additional quantity, in order to suppress the price on the amounts it did purchase. The buyer would end up with less than the optimal (competitive) level of the product (misallocating resources), but would have benefited by reducing its payments to suppliers (a wealth transfer).

How could buyers exercise market power in the NYISO's capacity markets?

The standard method by which LSEs buyers could exercise market power would be via decreasing their bids in the NYISO auctions. However, the LSEs are not allowed to decrease their bids in the NYISO spot auctions. Instead, their bids are determined by the capacity market demand curves, as specified in the NYISO tariffs. The demand curves provide a (sloped) floor on LSE bids, which prevents strategic withholding of demand. This is comparable to the offer caps on suppliers, which prevent "economic" withholding of supply in the capacity spot auctions. In short, the demand curves effectively mitigate the exercise of buyer-side market power (via economic withholding) in the capacity market spot auctions.

The only other means by which capacity buyers could exercise market power is by "uneconomic entry", i.e. physically building additional capacity, for the purpose of reducing the market price for the supply procured via the auctions. This is an example of "physical" market power; it is akin to physical withholding by a large supplier, e.g., by retiring a profitable plant in order to raise the prices received by its remaining supply.

How should buyer side market power be evaluated?

The same DOJ guidelines discussed above state that it is "necessary to evaluate both the probable demand responses of consumers and the probable supply responses of other firms. A price increase could be made unprofitable by any of four types of demand or supply responses: 1) consumers switching to other products; 2) consumers switching to the same product produced by firms in other areas; 3) producers of other products switching existing facilities to the production of the product; or 4) producers entering into the production of the product by substantially modifying existing facilities or by constructing new facilities. In determining whether any of these responses are probable, the Department usually must rely on historical market information as the best, and sometimes the only, indicator of how the market will function in the future. It is important to note, however, that the Guidelines are fundamentally concerned with probable future demand or supply responses." Justice Dept. Merger Guidelines, June 14, 1984, section 2.0 (pp. S-1 - S-2).

How can you apply these principles in the context of the NYISO's ICAP markets?

In order to accurately determine whether one or more LSEs would be in a position to exercise buyer-side market power, one must evaluate the probable demand responses of other LSEs and the probable supply responses. In particular, one must determine whether the LSEs would be able "profitably to maintain prices [below] competitive levels for a significant period of time". This is especially critical in the context of "uneconomic entry," which is the only potential avenue available to LSEs: such a strategy requires a heavy, long-term financial commitment.

"Uneconomic entry" in the NYISO capacity markets, especially in a densely populated locality such as New York City, would be difficult and costly. In order to suppress capacity prices in New York City, an LSE would have to obtain siting approval for a large new power plant, which is an arduous process that typically takes years to complete, if it can be accomplished at all. Then the LSE would have to pay the construction costs of the plant, and also pay for interconnection costs which can exceed $1000 per kW. And if the LSE actually succeeded in reducing the capacity market price, this would likely engender a market response that could quickly offset the hoped-for price suppression. For example, an incumbent supplier might choose to retire one of its less efficient generators, rather than pay the costs of its maintenance or repair. Also, capacity otherwise available from demand response or behind-the-meter generation might choose not to supply. As a result, the strategy of exerting buyer-side market power via "uneconomic entry" is unlikely to be profitable.

Have New York regulators addressed buyer-side market power in New York's capacity markets?

Yes. This issue has arisen in a number of transmission and generation siting cases before the NYPSC and the Siting Board. Developers may face significant local opposition to their projects, based on concerns for local (or global) environmental impacts or other public policy concerns. Under New York Public Service Law, New York's regulators are required to ensure such environmental and other public policy concerns are mitigated, and may deny siting approval for a project (whether merchant or requesting ratepayer support) if the economic benefits do not outweigh the unmitigated costs. Developers are required to provide testimony and supporting evidence for their economic and environmental impacts. Not surprisingly, developers may claim that their projects will benefit consumers by reducing capacity market prices. Developers may focus their claims on the capacity spot market, because it is easy to calculate an apparent benefit from any capacity addition, due to the relatively steep slopes of the capacity market demand curves.

For example, TDI proposed the CHPE project to deliver 1000 MW of (primarily hydroelectric) power from Quebec to Astoria, Queens (New York City). In its testimony in support, TDI estimated capacity spot market savings, based on forecasted price reductions, of $6.5 billion (undiscounted) over a 10-year period. [Case 10-T-0139, Julia Frayer direct testimony, p. 30, filed June 7, 2012] Other parties opposed CHPE, including IPPNY (representing incumbent suppliers), Entergy (an incumbent supplier in the Lower Hudson Valley), and IBEW (a union representing employees of incumbent suppliers). IPPNY argued CHPE would constitute "uneconomic entry," and would be subject to buyer-side mitigation (discussed below), prohibiting CHPE from selling capacity into the markets for many years.

The New York regulators have recognized that, in theory, any resource additions may temporarily reduce market prices. However, they have also recognized that such price impacts would lead to offsetting market responses. In evaluating resource additions, New York regulators focus on long-term costs and benefits, rather than short term price impacts. In the CHPE case, my testimony for the NYSDPS provided a long-term economic analysis. I testified that, absent CHPE, the most likely alternative resource would be 1000 MWs of combined-cycle gas-fired generation in New York City; thus the entry of CHPE would, in the long run, simply displace the entry of alternative resources. Nevertheless, I estimated that CHPE could provide net economic benefits, on a societal basis (ignoring wealth transfers), by substituting hydroelectric resources for potentially more expensive gas-fired generation; the results were, not surprisingly, very sensitive to forecasts of natural gas prices. Importantly, this analysis did not rely in any way on assumed capacity price suppression, since the long-run impact of the entry of 1000 MW via CHPE is simply to displace a comparable amount of alternative capacity resources in New York City, leaving ICAP prices unchanged in the long run. Instead, the analysis focused on natural gas prices, which are a key factor in analyzing New York's electricity markets.

In its order approving the line, the NYPSC stated: "Staff's long-run production cost savings is proper: it properly compares the cost of the added project to the cost savings that will result from it, in the form of an alternative project (a combined cycle gas facility located in New York City) that will be avoided. This analysis should be given the most weight. Its results are highly instructive because they show how sensitive the economics of the Facility are to gas price forecasts." [Case 10-T-0139, Order Granting Certificate of Environmental Compatibility and Public Need, April 18. 2013, p. 39.]

Have there been any historical examples of the exercise of buyer-side market power in New York's capacity markets?

Other parties have pointed to the Astoria Energy II (575 MW) power plant as an example of buyer-side market power. It is true that the entry of Astoria Energy II in July of 2011 led to an immediate decrease in New York City's capacity prices. However, the entry of Astoria Energy II did not, in fact, result in any sustained price suppression, and therefore could not represent a successful exercise of buyer-side market power. Instead, a comparable amount of older, less efficient and higher emitting resources was no longer needed to satisfy capacity obligations. The owners of those resources either decided to shut down, or declined to spend the capital necessary to bring units back online after an outage – outcomes consistent with legitimate public policy goals. This is precisely the type of response expected of a well-functioning market, and which proponents of competitive markets have always extolled.

Would technologies other than gas-fired generation be likely vehicles for the exercise of buyer-side market power?

No. Most non-gas-fired generation resources have higher installed costs per kW, are harder to site or takes longer to build than gas-fired generation, and thus are particularly unlikely to be used to exercise buyer-side market power. In the case of renewable resources, the relatively high development cost of such resources (and, in the case of intermittent renewable resources, their relatively lower capacity contribution) makes it unlikely that a buyer could use such a resource to drive down the market price sufficiently to recover the substantial cost of developing the resource. In the case of transmission lines (coupled with UDRs), the expense and long lead time for such projects would generally make them an ineffective tool for exercising buyer-side market power: developers of potential generation projects would simply take account of the transmission investment in adjusting the location and timing of their projects, offsetting any intended capacity market price impacts.

V. <u>Buyer Side Mitigation</u>

What are the current NYISO BSM rules?

The current BSM rules are described in detail in the testimony of Adam Evans, but as a general statement they place a floor on the capacity market offer price of a new supplier, unless it has received an exemption. This can lead to the new supplier being "priced out of the market," and receiving $0 for its capacity. The incumbent suppliers meanwhile receive a market-clearing price that remains high due to the enforced "withholding" of the new supply from the capacity markets. The effect is to penalize both the new supplier and all LSEs who purchase from the capacity market, to the benefit of incumbent suppliers. The BSM rules operate on the basis that all proposed new entry in a mitigated region is "presumed guilty unless proven innocent," regardless of the type of resource or the nature of the developer/procurement process.

Do the current NYISO BSM rules result in a more competitive ICAP market?

No, they result in a less competitive ICAP market. In a competitive market, all suppliers would compete to supply ICAP and would end up receiving a comparable market price for ICAP. But mitigation under the BSM rules may artificially restrict ICAP supply from new entrants, based on the BSM offer floors. This can result in mitigated supply receiving an effective price of $0 while other suppliers continue to receive high prices for the same product. This discrimination prevents the spot market prices from declining in response to new entry, contrary to the normal workings of a competitive spot market. More importantly, by blocking the normal market signals, the BSM rules can block the efficient market response to new entry, which is for ageing, less efficient, higher emitting resources to exit the market.

Which new entrants have been subjected to BSM offer floors in New York's capacity markets?

To date, offer floors have been applied to the Astoria Energy II generator (575 MW, NYC), the HTP transmission line (660 MW into NYC, with 320 MW of UDRs), the Berrians GTs (NYC), Cricket Valley (LHV), and Taylor Biomass (LHV); in addition, CHPE (1000 MW line into NYC) would have been mitigated, but opted to try again later in hopes of obtaining an exemption.

Do the BSM rules apply to repowering?

Yes, the BSM rules even apply to repowering projects that replace existing MWs with new MWs, despite the fact that repowering does not depress ICAP prices. Thus, an incumbent supplier that replaces an ageing steam or gas turbine plant with a modern, clean, efficient combined-cycle plant not only gets no additional payment from the ICAP market to compensate it for the costs of renovation, but actually risks losing its capacity payments. This is an especially egregious example of "mitigation gone wild." Such repowering can satisfy a variety of public policies, and cannot conceivably be considered "buyer-side market power" since it does not depress capacity prices.

What impact do the BSM rules have on New York's capacity markets?

In general, because the BSM rules are applied to all new entrants in mitigated zones, and involve so many judgmental assumptions, NYISO's BSM rules have created massive confusion, controversy and risk in mitigated regions. The BSM rules are applied to entrants that clearly have no intent to suppress capacity prices, including transmission projects and even renewable resources. Even when such entry has been justifiable on economic or public policy grounds, any new entrant seeking to rely on ICAP market revenues is subjected to cross-examination by its competitors. Rather than protecting competition, the BSM rules operate to prevent competition by erecting another barrier to entry. The current BSM rules are similar to a local zoning board meeting in which existing shop owners try to prevent a competitor from opening in the same neighborhood.

What impact do the BSM rules have on the New York City locality in particular?

The perverse impact of the BSM rules is that in precisely those regions where new entry is most valuable from both an economic and reliability perspective (i.e., Southeast New York), mitigation makes new entry most risky and effects a significant disincentive and barrier to entry. The New York City locality, in particular, already has many barriers to entry. Existing generation occupies valuable interconnection sites, forcing potential new entrants to assume the cost of building new lines and even new substations, at costs that can exceed $1,000/kW, even though the newer, cleaner generation could displace an old plant that would no longer be needed. The BSM rules perversely increase reliance on ageing, high-emission generating plants. This reliance further threatens reliability as older plants are more susceptible to unforeseen, catastrophic outages.

Does the Commission's recent approval of a CEE satisfy your concerns with the current BSM rules?

No. While the approval of the CEE is a good start, it does not address the fundamental problem with over-mitigation that I have discussed earlier in this affidavit. The BSM rules fail to recognize that new entrants have many attributes besides the products (energy and ICAP) that are traded via NYISO's markets. A new entrant may improve local reliability, local emissions, noise, fuel diversity, or other factors. A truly competitive market would allow buyers (through their duly elected representatives) to value the quality of the product being sold, not just its quantity, and in real markets, willingness to pay higher prices reveals such value. The BSM rules prevent consumers in mitigated regions from choosing to value the quality of their power supply, which thereby undermines one of the most important benefits of markets. Only by narrowing the universe of potential mitigation candidates to those resources that are solely developed with the intent to suppress market prices will the NYISO BSM rules be just and reasonable.

VI. <u>Recommendations</u>

What is your recommendation regarding NYISO's Buyer Side Mitigation?

My recommendation is that BSM should be limited to clear instances of intent to suppress capacity market prices. The sloped demand curve precludes buyers from exercising market power via strategic bidding in the spot auctions. The remaining buyer-side strategy, of exercising physical market power via "uneconomic entry," is unlikely to prove profitable; however, it might be tempting to naïve parties. To protect buyers from strategies that could prove costly failures in practice, without impeding the achievement of legitimate public policies, BSM rules should be narrowly focused on addressing a clear intent to suppress market prices.

As steps towards this goal, I recommend exempting transmission UDRs and non-gas-fired generation resources from the BSM rules. As I explained above, these technologies have higher installed costs per kW, are harder to site or take longer to build than gas-fired generation, and thus are particularly unlikely to be used as a tool to exercise buyer-side market power. I also support the recommendation to exempt self-supply, as testified to by Michael Cadwalader, because LSEs who do not purchase much from the capacity market would not benefit financially from the exercise of buyer-side market power.

Should capacity spot markets be protected from the impact of legitimate public policies?

No. All markets are impacted by public policies, and the capacity spot market should be no exception. An efficient capacity market will allow spot prices to reflect actual market conditions, by allowing prices to increase in cases of tighter supply and decrease in cases of excess supply. In particular, if a new plant enters service in a locality (covering the costs of deliverability to qualify for capacity payments), then the capacity spot price should be allowed to fall to reflect that additional supply. If the lower capacity price causes other plants to become unprofitable, then that sends an appropriate signal for other plants to consider exiting the market. Such price signals, and resulting market responses, are key to the efficient operation of spot markets. Blocking those signals, in order to prevent the resulting market responses, undermines the very purpose of a spot market.

Does this conclude your testimony?

Yes.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth herein are true to the best of my knowledge, information, and belief.

Thomas S. Paynter
Thomas S. Paynter

April 24, 2015

Subscribed and sworn to before me
this 24 day of April, 2015

Notary Public

LEONARD J. VAN RYN
Notary Public, State of New York
Qualified in Albany County
My commission expires 1/31/18
01VA4780265

My Commission expires: 1/31/18

Exhibit B

Affidavit of Michael D. Cadwalader

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Public Service Commission and New York Power Authority,	)	
Complainants,	)	
	)	**Docket No. EL15-__-000**
v.	)	
New York Independent System Operator, Inc.,	)	
Respondent.	)	

AFFIDAVIT OF MICHAEL D. CADWALADER

I, Michael D. Cadwalader, being duly sworn, depose and say:

1. My name is Michael D. Cadwalader. I am president of Atlantic Economics, an economic consulting firm. My business address is 540 Main Street, Suite 8, Winchester, Massachusetts 01890.

2. I received an A.B. degree, *summa cum laude*, in mathematics and economics from Washington University in St. Louis in 1985, an M.A. degree in economics from the University of Rochester in 1988, and an M.B.A., with distinction, in finance and strategic management from The Wharton School of the University of Pennsylvania in 1994.

3. For more than twenty years, I have been an economic consultant, initially with Putnam, Hayes & Bartlett and then with LECG, before founding Atlantic Economics. My consulting practice has primarily consisted of advising clients on the

development of competitive electricity markets, and assisting clients in understanding the implications of these markets for their businesses.

4. I have consulted with clients regarding the structure of the electricity markets operated by the New York Independent System Operator, Inc. ("NYISO"), ISO New England, PJM Interconnection LLC ("PJM"), the Midcontinent Independent System Operator, Inc., the California Independent System Operator Corporation, the Electric Reliability Council of Texas, and the Ontario Independent Electricity System Operator, as well as several markets outside North America. In many of these regions, this consulting activity included the development of proposals for markets for installed capacity ("ICAP"), or the assessment of ICAP market proposals developed by others.

5. My involvement in the development of the electricity markets operated by the NYISO began in 1994, several years before those markets began operation. Specifically, I assisted the Member Systems of the New York Power Pool (now known as the New York Transmission Owners) in the development of these markets, which they eventually transferred to the NYISO in accordance with Order No. 888. As part of that work, I was deeply involved in the development of the New York ICAP market. I was the primary author of the initial version of the NYISO's ICAP Manual, which defines the procedures that the NYISO uses to administer its ICAP market. I wrote the rules for the NYISO's ICAP auctions and developed the spreadsheet-based model that the NYISO initially used to conduct those auctions. I was also deeply involved in the development of the language in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff") that is used to govern the New York ICAP market.

6. Since the NYISO began to administer the electricity markets in New York in late 1999, I have been engaged by the New York Transmission Owners to advise them regarding the structure of the NYISO's ICAP market, among other things. I have been involved in the development of all of the major changes to the New York ICAP market that have occurred since the initial implementation of that market, including: the initial development of the NYISO's ICAP demand curves in 2002 and 2003; the determination of the parameters for those demand curves for 2005-08, 2008-11, 2011-14, and 2014-17; the development of enhanced procedures for reporting the potential impact of the exercise of market power, and measures for mitigating the exercise of market power in these markets; and the development of procedures for defining new capacity zones. I have submitted almost twenty affidavits to the Federal Energy Regulatory Commission ("Commission") over the years on a variety of capacity market-related issues, as described further in my *curriculum vita*, which is attached as Appendix B.

SUMMARY

7. In some circumstances, market participants may have an incentive to act in an anticompetitive manner, so the application of mitigation measures that are intended to counteract these incentives may be beneficial. However, there are risks to mitigation, due to the fact that it is not possible to mitigate perfectly; as a result, mitigation may do harm, by preventing market participants from acting in a competitive manner.

8. In cases where the NYISO concludes that an entrant is not economically justified, and that permitting it to sell ICAP would therefore suppress ICAP prices below competitive levels, it will assign an offer floor to that resource, which will prevent it from selling its ICAP for less than that offer floor. But if such an offer floor is inappropriately

applied, it may yield higher prices than those a competitive market would produce. The assessment of whether entry reflects anticompetitive behavior and therefore merits an ICAP offer floor is an inherently complex matter that requires the NYISO to make judgment calls on many issues. Consequently, there is a significant risk of inappropriate mitigation. In the NYISO's case, this risk is magnified by provisions in the Services Tariff that require the NYISO to make certain unrealistic assumptions in its assessment of whether a new resource is economic. As a result, if offer floor mitigation has not already been applied to economically justified entrants—and the NYISO's Market Monitoring Unit ("MMU") has made the case that it may have been—there is a very good chance that it will be applied to such entrants in the future; this, in turn, may deter such entrants from proceeding with entry, thereby driving the ICAP market away from the competitive equilibrium. That is exactly the opposite of the intent underlying the mitigation measures. Those measures are intended to counteract attempts to manipulate markets, thereby permitting those markets to produce outcomes that are closer to the competitive equilibrium.

9. In recognition of the likelihood that offer floor mitigation will be inappropriately applied pursuant to the NYISO's overbroad mitigation rules, those mitigation measures should be amended so that they do not apply to entry by entities that have no incentive to suppress ICAP prices below competitive levels. This would ameliorate the harm that such mitigation can cause. A self-supply exemption ("SSE"), which is the focus of this affidavit, would permit load-serving entities ("LSEs") to build or contract with resources that could provide their anticipated future needs for ICAP. An SSE, if it applies only to entry that is sponsored by entities that do not have an incentive

to suppress ICAP prices below competitive levels, will promote economic efficiency, as it avoids the application of offer floor mitigation in cases where it is unlikely that entry reflects an attempt to suppress prices below competitive levels, and where the likelihood of inappropriate mitigation is high.

10. The complaint to which this affidavit is appended seeks, among other things, to establish such an SSE.[1] Analysis in this affidavit demonstrates that the terms of the proposed SSE would ensure that it would not apply to entities with an incentive to suppress ICAP prices, and would significantly constrain any attempt to use it as a vehicle to suppress ICAP prices below competitive levels. Consequently, because it would help to limit the application of offer floor mitigation to cases that are more likely to reflect anticompetitive conduct, approval of the proposed SSE is in the public interest, as it should improve efficiency.

FACTORS THAT DETERMINE WHEN MITIGATION IS LIKELY TO BE BENEFICIAL AND APPROPRIATE

11. In a competitive market for a given product, the supply curve is determined by suppliers' offers, which reflect the marginal cost each supplier incurs to provide that product, while the demand curve reflects the marginal value that consumers derive from consuming that product. The competitive equilibrium is determined at the point where the supply curve and the demand curve for that product intersect. At the competitive equilibrium, social welfare (a.k.a. gains from trade)—which is defined as the total amount buyers were willing to pay for the products they consume minus the total

[1] *New York Public Service Commission and New York Power Authority v. New York Independent System Operator, Inc.*, Complaint of New York Public Service Commission and New York Power Authority, Docket No. EL15-__-000 (May 8, 2015) ("NYPSC/NYPA Complaint").

amount sellers were willing to accept for the products they provide—is maximized. Consequently, any actions that would cause market outcomes to deviate from the competitive equilibrium must reduce social welfare. They must entail either (1) making a trade that reduces social welfare, because the marginal cost incurred to supply the product exceeds the marginal value that the consumer realizes from consuming the product, or (2) not making a trade, even though that trade would increase social welfare, because the marginal cost that would have been incurred to supply the product is less than the marginal value the consumer would have realized from consuming that product.

12. Mitigation is intended to reverse of the effects of market manipulation. Therefore, mitigation, like manipulation, alters the offers made by suppliers or the bids made by consumers in some way. As a result, mitigation may in some cases cause market outcomes to deviate from the competitive equilibrium. If a market would produce a competitive outcome in the absence of mitigation, then the application of mitigation cannot be beneficial—because the competitive equilibrium already maximized social welfare—and may be harmful. For example, if a supplier's offer to provide a product was less than the marginal cost it incurs to provide that product because its offer was mitigated, that supplier might sell that product even though the market-clearing price is less than its marginal cost. Such a trade would reduce social welfare, because the marginal cost that would have been incurred to supply the product is less than the marginal value the consumer would have realized from consuming that product. Consequently, in this case, mitigation leads to inefficiency.

13. In some cases, a market participant may have an incentive to act in an anticompetitive manner—*i.e.*, a manner which reduces social welfare—because that

behavior may benefit that market participant. If the marginal cost that a supplier incurs to provide a product is less than the price in the competitive equilibrium, social welfare would be increased if that supplier sells that product, because some consumer who values it at the equilibrium price (or more) is willing to consume it. If that supplier nevertheless elects not to offer that product for sale (thereby physically withholding it), or if the price at which it offers to sell that product exceeds its marginal cost by a large enough amount that it does not sell that product (thereby economically withholding it), it will forego the margin (the difference between the market-clearing price determined in the competitive equilibrium and the supplier's marginal cost) that it would have earned from the sale of that product. But withholding that product may drive up the price at which the market clears, causing that price to exceed the market-clearing price that would have been determined in the competitive equilibrium, which in turn will increase the revenue that the supplier receives for its remaining sales. If this impact exceeds the margin foregone by the supplier on the product that it withheld from the market, then the supplier is better off. As a result, it has an incentive to act in an anticompetitive manner, even though withholding the product reduces social welfare (and would have caused the supplier to incur a loss if the impact on the revenue produced by the supplier's remaining portfolio had not been taken into account).

14. In these circumstances, applying mitigation can counteract the effect of anticompetitive behavior, thereby increasing social welfare. In the example in the preceding paragraph, if mitigation measures were to ensure that the supplier offered the product for sale at or near its marginal cost to produce that product, then those mitigation measures would increase social welfare by eliminating the opportunity for the supplier to

implement a withholding strategy. By limiting market participants' freedom in determining their own offers and/or bids, mitigation can counteract the incentives that some market participants, such as the supplier in the example in the preceding paragraph, may have to act in an anticompetitive manner. As a result, it can cause social welfare to be higher than the level that would have prevailed if mitigation had not been applied and market participants had been left free to act in an anticompetitive manner. But mitigation cannot cause social welfare to be higher than the level that would have prevailed in the competitive equilibrium, and it always carries the risk that it will be applied inappropriately, in which case it may actually reduce social welfare.

15. In the preceding example, suppose that the supplier with an incentive to withhold the product was mitigated, but that mitigation caused it to offer the product at less than its marginal cost to produce that product. In that case, mitigation might actually make things worse. It would require that the supplier produce the product, even though the marginal cost the supplier incurs to produce that product exceeds the marginal value that consumers realize from consuming that product. Consequently, social welfare would certainly be less than the level that would have prevailed in the competitive equilibrium, and might even be less than the level that would have prevailed if there had not been any mitigation. Thus the application of mitigation may be counterproductive.

16. Two general lessons can be drawn from this discussion. First, when assessing whether mitigation ought to be applied, one should consider whether it is likely to be in a market participant's interest to act in an anticompetitive manner. If there is not a reasonable likelihood that a market participant will act in an anticompetitive manner, then there is a good chance that the application of mitigation will actually be harmful.

Like the supplier who was required to submit a below-cost offer, mitigation in such cases may require the market participant to act in a way that is inconsistent with the competitive equilibrium. As a result, mitigation may cause the market to move away from the competitive equilibrium, thereby reducing social welfare. This argues against the application of mitigation in such cases.

17. Second, when assessing whether mitigation ought to be applied, one should consider how accurately one can determine the offer or bid that a market participant would have submitted if it had been acting in a competitive manner. If it is difficult to tell what offer a market participant would have submitted if it had been acting competitively, it becomes more likely that the application of mitigation will fail to reflect what would have happened in a competitive marketplace, and that as a result, mitigation will make things worse. Consequently, holding all other factors equal, when there is more ambiguity as to what constitutes competitive behavior, mitigation is less likely to produce improvements, and should therefore be employed less often. Generally speaking, mitigation programs should be narrowly defined and carefully applied.

MITIGATION MEASURES IN THE NYISO'S ICAP MARKET

18. While the NYISO also operates other ICAP auctions, the NYISO's spot market auction ("SMA"), which is conducted shortly before the beginning of each month, determines the amount of ICAP that is actually provided in that month in the New York Control Area ("NYCA") as a whole and the three Localities contained within the NYCA. The NYISO uses a nested structure for its locational ICAP requirements. Two of its Localities—New York City ("NYC") and Long Island—do not contain any other Localities, but the third Locality, called the G-J Locality ("G-J"), includes both NYC

(a.k.a. Load Zone J) as well as the Lower Hudson Valley ("LHV") (a.k.a. Load Zones G through I).

19. The ICAP supply curves used in the SMA are based on the offers to provide ICAP that suppliers submit. The ICAP demand curves, on the other hand, are administratively determined. The NYISO conducts a study every three years to set these demand curves. As part of that study, the NYISO identifies the proxy generator for each Locality and for the NYCA as a whole, which is the peaking generator that could be built in each of those regions at the lowest net cost.[2] The ICAP demand curve for each of those regions is then set with the objective of ensuring that the overall revenue stream that would be expected to flow to the proxy generator for that region would be sufficient to support entry of that unit, under certain assumptions regarding the amount of ICAP that would be provided in each region on average, relative to the ICAP requirement for that Locality.[3]

20. The intersection of the supply curve for a given region and the ICAP demand curve for that region determines the minimum price of ICAP in that region[4] and the amount of ICAP supplied in that region. The ICAP purchase obligation for each LSE—*i.e.*, the amount of ICAP that LSE is required to purchase in the SMA, if it has not

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[2] Services Tariff § 5.14.1.2.

[3] *Id.*

[4] The price of ICAP in a Locality may exceed this minimum price. Since Long Island is contained within the NYCA, the price of ICAP on Long Island is the greater of the Rest of State ("ROS") price, which is the price at the intersection of the NYCA demand and supply curves, and the price at the intersection of the Long Island demand and supply curves. The LHV is also contained within the NYCA, so the price of ICAP in the LHV is the greater of the ROS price and the price at the intersection of the G-J demand and supply curves. (For that reason, this price is also sometimes called the G-J price, even though it usually only applies to ICAP in the LHV, rather than ICAP throughout G-J.) Finally, since NYC is contained in both the NYCA *and* G-J, the price of ICAP in NYC is the greatest of the ROS price, the LHV price, and the price at the intersection of the NYC demand and supply curves.

procured it before then—is then calculated by allocating the total ICAP purchase obligation in a given region among the LSEs in that region, in proportion to each LSE's share of forecasted peak load for that region.

21. Under the NYISO's current ICAP market rules, mitigation measures apply to two Mitigated Capacity Zones ("MCZs"): NYC and G-J.[5] Mitigation does not apply elsewhere because there has been no finding that the conditions that are likely to provide market participants with incentives to act in an anticompetitive manner are present there, and as a result, mitigation might do more harm than good. The mitigation measures in effect in these MCZs include both offer cap mitigation, which is intended to counteract incentives for suppliers to raise prices above competitive levels, and offer floor mitigation, which is intended to counteract incentives for consumers (buyers) to suppress prices below competitive levels.[6]

22. A supplier of ICAP in an MCZ may be exempt from offer cap mitigation if the total amount of ICAP it controls in that MCZ is less than the pivotal supplier threshold that has been established for that MCZ, which is intended to assess whether that supplier might have a financial incentive to withhold ICAP.[7] Thus offer cap mitigation is targeted narrowly at the subset of suppliers whom the NYISO believes may have an

[5] MCZs include "New York City and any Locality added to the definition of 'Locality' accepted by the Commission on or after March 31, 2013." Services Tariff § 2.13. On August 13, 2013, the Commission accepted the NYISO's proposal to define a new capacity zone consisting of Load Zones G through J. *New York Indep. Sys. Operator, Inc.*, 144 FERC ¶ 61,126 (2013).

[6] Offer cap mitigation and offer floor mitigation are often called supply-side mitigation and buyer-side mitigation, respectively.

[7] Section 23.4.5.2 of the Services Tariff applies offer caps to offers to sell Mitigated Unforced Capacity ("UCAP") in SMAs. Mitigated UCAP is defined in section 23.2.1 of the Services Tariff as "one or more megawatts of Unforced Capacity that are subject to Control by a Market Party that has been identified by the ISO as a Pivotal Supplier." Consequently, offers of UCAP in MCZs by non-Pivotal Suppliers are not subject to offer caps.

incentive to withhold ICAP. Offers to sell ICAP from a resource in an MCZ that is subject to offer cap mitigation cannot exceed the greater of the price at which the market is expected to clear if all ICAP in that region is sold in the SMA or the Going-Forward Costs ("GFCs") for that resource;[8] GFCs, in turn, are the greater of the NYISO's estimate of the marginal costs that resource will incur to provide ICAP or the revenue it would forego by not selling its ICAP outside the NYISO.[9] Jointly, these measures are intended to ensure that suppliers submit competitive offers in cases where they may have an incentive to attempt to increase prices above competitive levels by acting in an anticompetitive manner. A supplier that is acting in a competitive manner should be willing to supply ICAP if the price was greater than the cost it incurred to provide ICAP or the price it could obtain elsewhere; consequently, the mitigation measures are intended to require resources subject to those measures to submit such offers. Decisions by suppliers to retire or mothball resources are also subject to review to ensure that they are not motivated by an attempt to raise prices above competitive levels.[10]

23. There is no need for the NYISO to mitigate bids to purchase ICAP that might indicate an attempt to suppress prices below competitive levels in the SMA, because the amount of ICAP purchased in each region in the SMA at each price is determined by the administratively determined ICAP demand curve. Since there is no opportunity for any market participant to submit bids to purchase ICAP in the SMA, there is no opportunity to suppress prices below competitive levels in this manner. However, consumers (buyers) could attempt to suppress prices below competitive levels

[8] Services Tariff § 23.4.5.2.

[9] *Id.* § 23.2.1, definition of Going-Forward Costs.

[10] *Id.* § 23.4.5.6.

by subsidizing the development of uneconomic capacity. If the entry of that capacity lowers prices by a large enough amount, the impact of that price reduction on payments for ICAP that consumer purchased in the market could exceed the cost of the subsidy, thereby reducing the total amount that consumers pay for ICAP.[11] To address the possibility of buyer-side manipulation, the NYISO applies a floor to any offers to sell ICAP provided by *any new resource* in an MCZ that fails the Mitigation Exemption Test ("MET").[12] The MET consists of two parts.

24. Under what is called the Part A test, such a resource will be exempted from offer floor mitigation, and will be permitted to submit whatever offer it chooses for the ICAP it provides, if the NYISO's forecast of the average ICAP price in the first year of the Mitigation Study Period ("MSP") for the location where that resource will provide ICAP is greater than the default net Cost of Net Entry ("CONE"), which is set at 75 percent of the net cost of developing the proxy generator for that location.[13] Consequently, this test does not attempt to assess whether a given resource is economically justified, because exemptions granted under this test are intended to ensure that the NYISO does not inadvertently prevent new resources from supplying ICAP that is needed to meet the ICAP requirement for an MCZ.

25. Under the Part B test, the resource will be exempted from offer floor mitigation if the NYISO's forecast of the average ICAP price over the three-year MSP at

[11] This price reduction may be transitory, as other generators may retire or mothball in response to the price reduction caused by the uneconomic entry, which would offset some or all of the impact of the uneconomic entry on ICAP prices.

[12] For simplicity, throughout this affidavit, I will refer simply to new resources, but those references are also intended to address cases when existing resources seek to provide additional ICAP, as the MET will also apply to such resources.

[13] Services Tariff § 23.4.5.7.2.

the location where that resource will provide ICAP is greater than the Unit Net CONE, which is the ISO's estimate of the net cost of developing the resource in question—*i.e.*, the ICAP payment that is expected to permit the developer to break even on its investment.[14] Exemptions under this Part B test are intended to ensure that the NYISO does not mitigate offers to provide ICAP from resources that are expected to be economically justified.

26. If an entrant in an MCZ is not exempted under either the Part A test or the Part B test, it can only sell its ICAP in the SMA, and its offers to sell that ICAP cannot be less than an offer floor,[15] which is based on the lesser of the default net CONE for that MCZ or the Unit Net CONE that been calculated for that resource. Consequently, the owner of such a resource will not be able to sell ICAP provided by that resource if the market-clearing price is less than the offer floor for that resource. It is important to recognize the number of forecasts and estimates involved in these calculations. Inaccuracies or unreasonable assumptions may cause mitigation to be applied inappropriately and thus inefficiently.

APPLYING OFFER FLOOR MITIGATION CAN DISCOURAGE ECONOMIC ENTRY

27. In general, it is easier to apply mitigation accurately in markets that apply to shorter time periods, such as the energy market. That is because a competitive offer in the energy market should reflect the costs that a supplier would avoid incurring if it were not to provide energy, and the scope of the costs that can be avoided in a short time period is usually narrow. Therefore, the estimate of what constitutes a competitive

[14] *Id.*

[15] *Id.* § 23.4.5.7.

energy offer for a thermal generator is usually relatively straightforward, as the marginal costs that such a generator will incur to produce energy will generally depend primarily upon the price of its fuel and the rate at which it consumes that fuel. There are some situations where this assessment is more complicated (*e.g.*, hydro units with pondage capability), but these are cases where a longer time horizon is relevant (because such a hydro unit may forego future sales if it sells energy today).

28. In contrast, the determination of the Unit Net CONE for a prospective entrant is quite complex. The NYISO must not only develop estimates of the costs of developing a power plant, but must also assess the financing arrangements for that facility and the revenue that resource can reasonably expect to earn in the energy and ancillary services markets to estimate how much ICAP revenue a prospective developer would require in order for it to proceed with development, if it is acting competitively. In addition, to apply the MET, the NYISO must forecast ICAP prices several years in advance.

29. Potomac Economics, Ltd., the MMU, issues reports reviewing the NYISO's MET determinations, which detail the myriad assumptions that the NYISO makes when it conducts the MET. Unfortunately, as the MMU has pointed out in recent reports, there is reason to believe that some of the assumptions that the Services Tariff requires the NYISO to make when it conducts its MET are, in fact, unreasonable, and that as a result, resources that are actually economic may nevertheless be subject to offer floor mitigation. For example, in its recently released review of the MET that was performed for resources in Class Year 2012, the MMU pointed out that the ICAP price forecasts used in the Part A and Part B tests assumed that all mothballed generators, as well as

generators that must transfer their Capacity Resource Interconnection Service rights in order for new capacity to be deliverable, would be in service and sell capacity.[16] These assumptions depressed the forecast of ICAP prices as well as the forecast of net energy and ancillary services revenue, which increased Unit Net CONE. Since exemptions are granted if forecasted ICAP revenue exceeds Unit Net CONE, both of these effects increase the likelihood that exemptions will not be granted to economically justified resources, and the MMU concluded in this case that they may have caused a resource to be mitigated when the use of more realistic forecasts might have led to an exemption from offer floor mitigation.[17] The NYISO made similar assumptions regarding the treatment of these generators when it performed an earlier MET for facilities that were included in Class Year 2011.[18]

30. These are not the only assumptions that may have led the NYISO to conduct an unrealistic assessment of whether entrants were economically justified. As the MMU also pointed out in the Class Year 2012 Report, the MSP used for the members of Class Year 2012 begins in May 2015, as required by the Services Tariff.[19] Consequently, the NYISO's determination of whether to exempt these resources from the offer floor implicitly assumes they would enter service in 2015, but the MMU pointed out

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[16] Potomac Economics, Ltd., *Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2012 Projects* at 13-14, 17, 45-46, 47 (Jan. 13, 2015) ("Class Year 2012 Report"), *available at* http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Class%20Year%202012/MMU%20Report%20on%20CY%202012%20BSM%20Tests.pdf.

[17] *Id.* at 14.

[18] Potomac Economics, Ltd., *Assessment of the Buyer-Side Mitigation Exemption Tests for the Berrians Facility* at 25 (Oct. 15, 2013), *available at* http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/In-City_Mitigation_Documents/In-City_Mitigation/Berrians%20MET%20MMU%20Report__10-15-13.pdf.

[19] Class Year 2012 Report at 16-17, 29.

that those resources are actually expected to enter the market anywhere from 2016 to 2018.[20] Load growth occurring between 2015 and the times when these resources are actually expected to enter service would increase the ICAP price forecasts used in the Part A and Part B tests. It would also increase forecasted net energy and ancillary services revenue, thereby decreasing the Unit Net CONEs used for the Part B tests for these resources. Consequently, if the beginning of the MSP corresponded to these resources' actual anticipated entry dates, the likelihood that they would be found to be economic and would be exempted from mitigation would increase. But because the MSP is set in a manner that does not correspond to the expected entry date, resources that are expected to be economic at the time they are expected to enter service, and which would have been exempted from the offer floor if the MSP had begun at the time they are actually expected to enter service, may instead not be exempted, because the Services Tariff requires that they can only receive an exemption if they would have been economic in 2015.[21]

31. In addition to the impact of these assumptions, the NYISO's calculation of Unit Net CONE is subject to judgment in other areas. While it may not be clear whether the NYISO's judgment or the developer's judgment is superior in those areas, the mere fact that there is a difference does not necessarily demonstrate anticompetitive intent on the part of the developer. For example, the Class Year 2012 Report indicates that, in the course of conducting the MET, the NYISO (among other things):

[20] *Id.* at 29 n.49.

[21] *Id.* at 43-44.

- Developed a methodology for allocating costs of common facilities among multiple units.[22]
- Forecasted emissions allowance prices and their impact on electricity prices.[23]
- Assessed the impact that transmission congestion would have on energy prices.[24]
- Reviewed the circumstances underlying an operating exception which could alleviate that congestion, and assessed whether a similar exception might be forthcoming.[25]
- Estimated the cost of energy that would be purchased in Quebec and transmitted to NYC.[26]
- Assessed how combined cycle units in NYC might be scheduled to operate so as not to jeopardize their eligibility for a property tax exemption.[27]

32. Each of these decisions requires judgment and there is a "range of reasonableness" every time such a judgment is made. Combined with the compounding effect of the multiple times judgment is exercised, one ends up with a very broad range in which perfectly reasonable persons could land. The consequence is that a developer who may have made entirely reasonable assumptions may still be mitigated if those judgments lead it to a conclusion that entry is economically justified that does not match the conclusion the NYISO reaches, based on its own assumptions and judgments.

33. In addition, the Part B test, which is the unit-specific test intended to assess whether a new resource is economically justified, only covers the three-year MSP,

[22] *Id.* at 23-25.

[23] *Id.* at 32-33.

[24] *Id.* at 33-34, 37-38.

[25] *Id.* at 42.

[26] *Id.* at 34-35, 38-41.

[27] *Id.* at 36-37.

which is far shorter than the anticipated lifespan of any new generator. Consequently, it may conclude that a generator is not economically justified over that period when the developer, taking a longer view, may reasonably come to the opposite conclusion.

34. If a resource is economically justified, applying offer floor mitigation may cause harm, for two reasons. First, for the reasons given above, the offer floor may overstate the Unit Net CONE, which is intended to reflect the actual net cost of developing that resource. As a result, by preventing that resource from selling ICAP even when the price of ICAP exceeds its net cost, the offer floor may deter that resource from entering the market even though it is economically justified.

35. Second, the application of offer floor mitigation to an economically justified entrant may deter it from entering, *even if its Unit Net CONE has been correctly calculated.* Suppose, for example, that a developer is considering a new resource whose Unit Net CONE is expected to be $10/kW-mo. At the time it must decide whether to proceed with development, the developer anticipates a 50 percent chance that the future price of ICAP will be $14/kW-mo., and a 50 percent chance it will be $8/kW-mo. Ordinarily, this developer would proceed with the project. While it recognizes the possibility that it will only earn $8/kW-mo. on its project, it would be willing to accept this risk, since the average ICAP revenue it expects to earn is 50% × $14/kW-mo. + 50% × $8/kW-mo. = $11/kW-mo., which is greater than its $10/kW-mo. Unit Net CONE. But suppose that the NYISO forecasts that ICAP prices will average less than $10/kW-mo.; as a result, the resource does not pass the MET. If this resource is assigned an offer floor equal to its $10/kW-mo. Unit Net CONE, then there is a 50 percent chance it will not receive any ICAP revenue at all, so the average ICAP revenue it expects to earn will be

only 50% × \$14/kW-mo. + 50% × \$0/kW-mo. = \$7/kW-mo., far short of its \$10/kW-mo. Unit Net CONE. Therefore, it will not proceed with development, even though the developer expects the resource to be economically justified.

36. Even if ICAP prices are expected to be high enough on average to support its development of a new resource, ICAP prices might not be high enough to support that development *in all scenarios*. If there were no offer floor in place, then the developer would take the risk that it would receive lower-than-expected ICAP prices into account when deciding whether to proceed. But the application of an offer floor may exacerbate these consequences significantly: In such cases, the offer floor may preclude that resource from selling any of its ICAP, even though there was no reason to expect, at the time that the decision to proceed with development of the resource had to be made, that it would turn out to be uneconomic. As a result, the application of an offer floor to new resources that are expected to be economically efficient would and does discourage the development of those resources.

THE PROPOSED SELF-SUPPLY EXEMPTION

37. As the preceding section makes clear, the application of offer floor mitigation will not always yield the intended result. While the mitigation is not intended to deter economically justified entry, it may nevertheless do so if the NYISO incorrectly determines that a resource is not economically justified and should be mitigated. And given the wide scope of decisions that the NYISO must make when assessing whether an entrant is economically justified or not, as well as the assumptions that the Services Tariff requires it to make when conducting the MET, there is a reasonable likelihood that from

time to time, it will, in fact, incorrectly conclude that an economically justified resource should be mitigated.

38. To the extent the NYISO's offer floor mitigation procedures deter economically justified entry, they move the market away from the competitive equilibrium, when the objective of mitigation should be to move the market towards the competitive equilibrium. To avoid such undesirable consequences, offer floor mitigation should be narrowly tailored to guard against the harm that may result from over-mitigation, by limiting offer floor mitigation to circumstances in which there is a reasonable expectation that a market participant will act in an anticompetitive manner to suppress ICAP prices. In another affidavit accompanying the NYPSC/NYPA Complaint, Dr. Thomas Paynter of the New York State Department of Public Service argues that offer floor mitigation should be limited to entrants using the technologies that are most likely to be used in any attempt to suppress market-clearing prices for ICAP below competitive levels.[28] Even among those resources, exemptions from offer floor mitigation should be available in cases where the entity sponsoring the new resource has no financial incentive to support economically unjustified entry.

39. Late last year, Consolidated Edison Company of New York, *et al.* filed a complaint asking the Commission to direct the NYISO to exempt from offer floor mitigation the ICAP provided by new resources that are developed on a merchant, unsubsidized basis, as the owners of these resources would have no incentive to suppress prices below competitive levels.[29] The Commission recently granted that complaint,

[28] NYPSC/NYPA Complaint, Exh. A (Aff. of Thomas S. Paynter) ("Paynter Aff."), at 17:22-18:9.

[29] I submitted an affidavit in that docket, arguing that such an exemption would be appropriate. *Consolidated Edison Company of New York, Inc., et al., v. New York Independent System Operator, Inc.,*

concluding that "NYISO's current buyer-side mitigation rules should not be applied to competitive unsubsidized merchant resources because these resources do not have the incentive to exercise buyer-side market power,"[30] and directed the NYISO to file the tariff changes needed to implement that exemption.

40. Like that complaint, the NYPSC/NYPA Complaint also asks the Commission to direct the NYISO to exempt from offer floor mitigation the ICAP provided by entities that have no incentive to suppress prices below competitive levels. While differences between the structure of the ICAP markets administered by the NYISO and PJM necessitate certain differences between the procedures, the conditions under which the SSE proposed herein for New York would exempt ICAP provided by newly built resources from offer floor mitigation are generally similar to the conditions under which the SSE that PJM proposed and the Commission accepted in 2013 would exempt ICAP provided by newly built resources from offer floor mitigation.[31] Specifically, like PJM's SSE, the SSE proposed for New York would permit LSEs to build or contract for resources, within specific limits, that are sufficient to meet their own reasonably anticipated shares of the ICAP purchase obligations in each Locality, thereby permitting them to hedge their exposure to their future ICAP purchase obligations.

41. Practically speaking, it is unlikely that an LSE will be able to develop a portfolio of resources that provides the amount of ICAP that is needed to offset its ICAP

Motion for Leave to Answer and Answer of Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., New York State Electric and Gas Corp., Rochester Gas and Electric Corp., and Central Hudson Gas and Electric Corp., Docket No. EL15-26-000 (filed Jan. 30, 2015), Exh. F (Aff. of Michael D. Cadwalader).

[30] *Consol. Edison Co. of New York, Inc. v. New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,139 at P 46 (2015).

[31] *PJM Interconnection, LLC,* 143 FERC ¶ 61,090 at PP 63-115 (2013) ("PJM Order").

purchase obligations exactly, for several reasons. First, an LSE's future ICAP purchase obligations depend on numerous factors, including the ICAP requirements for the NYCA and the Localities that are established by the NYISO and the New York State Reliability Council, which may change from year to year; the amount of surplus ICAP (*i.e.,* ICAP above minimum requirements) sold in the SMA, which may change from month to month; and the contributions to forecasted peak load of the consumers that LSE serves, which may change from year to year. None of these are known at the time an LSE must decide whether to proceed with development of a given resource. Second, the amount of unforced capacity ("UCAP")[32] that each resource will provide is also not known in advance, as it depends upon the results of testing to determine the maximum amount of electricity that resource will be able to provide on a sustained basis (its Dependable Maximum Net Capability ("DMNC")), as well as that resource's history of forced outages. Third, the amount of UCAP that various resources can contribute is not infinitely divisible. Even if the LSE knew the amount of UCAP it would require, and the amount of UCAP that each resource would be able to provide, it is unlikely that it would be practicable or make economic sense for it to develop a portfolio in which the two would match exactly due to the lumpiness of resource development. Therefore, it is likely that an LSE that wishes to qualify for the SSE will, to some extent, either have less ICAP than it needs to meet its ICAP purchase obligations in a given MCZ (*i.e.,* it will be "net short") or it will have more ICAP in that MCZ than it needs to meet its ICAP purchase obligations (*i.e.,* it will be "net long").

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[32] UCAP is the metric that the NYISO uses to determine each resource's contribution to ICAP requirements, and each LSE's obligation to procure ICAP.

42. While an appropriately designed SSE should accommodate reasonable variations in LSEs' net short or net long positions, the SSE must also ensure that the LSEs to which it applies do not have an incentive to suppress prices below competitive levels. This necessitates limits on the net short position of LSEs that are eligible for the SSE. Suppose that an LSE has a net short position that is significantly larger than the amount of ICAP that would be provided by the resource it proposes to develop. It would buy much of the ICAP needed to meet its ICAP purchase obligation from the NYISO-administered markets, even after the new resource enters the market and begins to provide ICAP. Such an LSE may have an incentive to subsidize the entry of an new resource that is not economically justified—*i.e.*, a resource whose ICAP costs more than the price the LSE could have paid for that ICAP in the market—because the entry reduces the market-clearing price that such an LSE must pay for the remainder of its ICAP purchase obligation. If the cost of the subsidy (*i.e.*, the difference between the cost of the ICAP purchased from that resource and the cost at which that ICAP could have been purchased from the market) is less than the net impact of that entry on the amount that LSE must pay for its ICAP purchase obligation that remains after accounting for the ICAP provided by the new generator, then the LSE would have an incentive to pay the subsidy. Consequently, establishing a maximum net short threshold for LSEs that are eligible for the SSE can ensure that the SSE is not applied in cases where there is reason to suspect a market participant might act in an anticompetitive manner, as mitigation might be justified in such cases.

43. Another concern is that an LSE, possibly a state-affiliated LSE, could use the SSE as a conduit to force ICAP provided by uneconomic entrants into the market

without regard for the economic impact on its financial outcomes, in order to achieve a broader market-wide reduction in the ICAP prices paid by all affected load. If that LSE's net short position is less than the maximum net short threshold described in the preceding paragraph, then subsidizing uneconomic entry should increase that LSE's ICAP costs, as the cost of the subsidy would be greater than the impact of the uneconomic entry on the cost that the LSE incurs in meeting the remaining portion of its ICAP purchase obligation. But this uneconomic entry would also suppress the price paid for ICAP by other LSEs in the state, so that the impact of the uneconomic entry on the total amount paid for ICAP by *all LSEs* might be greater than the cost of the subsidy. The potential for such actions was illustrated by events in PJM which, as the Commission recognized, necessitated changes to PJM's offer floor mitigation procedures to counteract the possibility that ICAP prices could be suppressed significantly below competitive levels in this manner.[33]

44. Two provisions of the SSE are intended to address this concern. First, only entities with a history of self-supplying their ICAP purchase obligations are eligible for the SSE. Without this limitation, it theoretically might be possible to create a new LSE serving a large amount of load that would self-supply all of the ICAP needed to meet its ICAP purchase obligation, even though it could meet its ICAP purchase obligation less expensively in the ICAP market. The resulting uneconomic entry could suppress ICAP prices significantly below competitive levels. By requiring that eligible LSEs have a history of self-supplying their obligations, the proposed SSE would prevent such a strategy from being employed.

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[33] *PJM Interconnection, LLC*, 135 FERC ¶ 61,022 at P 139 (2011).

45. Second, eligibility for the SSE is limited to LSEs that satisfy a maximum net long threshold. The maximum net short and net long thresholds jointly ensure that eligibility for the SSE is limited to LSEs whose ICAP portfolios are reasonably consistent with anticipated levels of their future ICAP purchase obligations. The maximum net long threshold also limits the amount of ICAP provided by a new resource that can qualify for the SSE, as it cannot exceed the difference between the net long threshold and the LSE's ICAP holdings before adding capacity from the new resource (which should be close to its ICAP purchase obligations, since all qualifying LSEs must have a history of self-supplying those obligations).

CALCULATION OF MAXIMUM NET SHORT THRESHOLDS

46. The general intent of the analyses described in this section is to establish maximum net short threshold thresholds that will ensure that implementation of the SSE would not inadvertently provide an exemption from offer floor mitigation to a new resource that is sponsored by an LSE that has a financial incentive to sponsor entry of an uneconomic new resource, when that LSE would not have otherwise been eligible to receive an exemption from offer floor mitigation. The process that I use to calculate maximum net short thresholds consists of the following five steps:

47. The first step is to establish the market conditions that are assumed to prevail after the entry of a new generator that, in the absence of the SSE, might be subject to offer floor mitigation. Whether an LSE has a financial incentive to sponsor the entry of uneconomic generation can depend significantly on market conditions.

48. In the second step, I calculate the payments to a new generator that would be required to support entry.[34] Whether an LSE has a financial incentive to sponsor the entry of uneconomic generation can also depend significantly on the cost of supporting that entry.

49. In the third step, I calculate the cost that an LSE would incur to procure ICAP if it were to sponsor entry of a new generator that is not economically justified. Part of this consists of the payments the LSE would have to make to support development of that new generator, which were calculated in the second step, but this also includes the amount that LSE would have to pay in the SMA for its remaining ICAP purchase obligations, after taking into account the impact of the ICAP provided by the new generator on (1) the amount of ICAP it is required to purchase in the SMA and (2) the price of that ICAP.

50. In the fourth step, I determine how much the LSE would pay for ICAP purchased in the SMA if it were not to sponsor entry of such a generator. Because the LSE is not sponsoring the new generator, and therefore will not be able to use the ICAP that generator would have provided to reduce its ICAP purchase obligation, it would purchase more ICAP than if it had sponsored entry, and would pay a higher price than the price that would have prevailed if it had sponsored entry. But it would not have to make payments to support the uneconomic entrant.

51. In the fifth and final step, I compare the cost that an LSE would incur to procure ICAP if it were to sponsor entry of a new generator that is not economically

[34] Even if the LSE develops the generator itself, it is still appropriate to calculate these payments, as they reflect the net cost that LSE would incur to develop that generator.

justified to the costs it would incur if it did not sponsor entry of such a generator. If the former exceeds the latter, then it does not have a financial incentive to sponsor that entry, since doing so raises its costs. These incentives will depend upon the proportion of load that the LSE serves, so this step calculates how the maximum net short position that an LSE that serves a given proportion of load can have (after accounting for the impact of the new generator on its net short position), without having a financial incentive to sponsor uneconomic entry, will change as the proportion of load it is assumed to serve changes.

52. This five-step analysis is performed twice, first to calculate the maximum net short threshold that would determine whether an LSE sponsoring a new resource in the LHV would be eligible for an exemption from offer floor mitigation under the SSE, and then to determine whether an LSE sponsoring a new resource in NYC would be eligible for such an exemption. In addition, the calculation of the maximum net short threshold that would be applied in NYC is split into two parts, depending on whether the LSE also serves load in the LHV.

Maximum Net Short Threshold for Entry in the LHV

53. While LSEs serving load in NYC will generally be required to procure some UCAP in the LHV, the amount of LHV UCAP they are required to procure will generally be quite small compared to their UCAP purchase obligations elsewhere,[35] so

[35] In the summer 2014 capability period, the UCAP purchase obligation for G-J averaged 13,610.2 MW, which is 83.5 percent of G-J's forecasted peak load of 16,291.4 MW, while the UCAP purchase obligation for NYC averaged 9,574.8 MW, which was 81.3 percent of NYC's forecasted peak load of 11,782.8 MW. Therefore, the LHV UCAP purchase obligation for NYC loads averaged 2.2 percent of forecasted peak load. In the winter 2014-15 capability period, the UCAP purchase obligation for G-J averaged 14,977.0 MW, or 91.9 percent of G-J's forecasted peak load, while the UCAP purchase obligation for NYC averaged

they have very little incentive to sponsor uneconomic entry in the LHV to suppress the G-J ICAP price.[36] Consequently, the analysis of the maximum net short threshold for an LSE that is developing a new resource in the LHV will focus on the effect that entry of an uneconomic resource would have on the amount paid for ICAP by an LSE that serves load in the LHV (since those LSEs purchase much of their ICAP from resources in the LHV and may therefore have a financial incentive to sponsor uneconomic entry that would suppress the G-J ICAP price below competitive levels), and how that effect changes as the amount of load served in the LHV by that LSE changes.

Step 1: Market Conditions at Which the Impact of New Generation in the LHV Will Be Assessed

54. Because market conditions will significantly affect financial incentives for LSEs to sponsor uneconomic entry, it is necessary to determine the market conditions that are most likely to provide an incentive for LSEs to sponsor entry of uneconomic resources, and to assess whether the SSE would authorize exemptions in such cases for resources that would not have received an exemption otherwise. As the following simple example will show, financial incentives for LSEs to sponsor uneconomic entry generally weaken as the competitive price of ICAP falls.

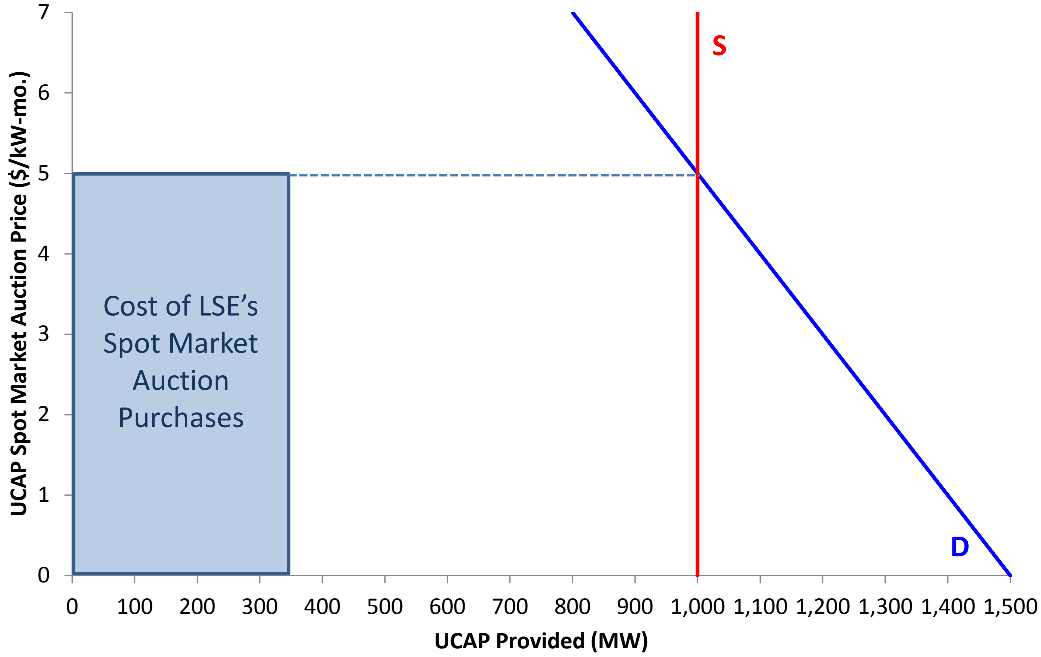
10,488.0 MW, or 89.0 percent of NYC's forecasted peak load, so the LHV UCAP purchase obligation for NYC loads averaged 2.9 percent of forecasted peak load.

[36] As described *supra* note 4, the price of ICAP in NYC may be set equal to the price of G-J ICAP. If that were the case (and were expected to continue to be the case), LSEs serving load in NYC could have a financial incentive to sponsor uneconomic entry in the LHV with the objective of suppressing G-J ICAP prices, and hence NYC ICAP prices. However, the average NYC UCAP price last summer (the first summer that the G-J Locality was in effect), \$18.51/kW-mo., was about 50 percent higher than the average G-J UCAP price of \$12.16/kW-mo., and the average NYC UCAP price this winter, \$8.36/kW-mo., was more than twice the average G-J UCAP price of \$4.04/kW-mo. Consequently, there is no evidence that NYC prices are particularly close to G-J prices. Nor am I aware of any evidence that NYC prices are likely to fall to G-J levels in the near future.

55. Consider an LSE that serves 35 percent of the load in an area, and which purchases all of its UCAP in the spot market auction. In Scenario 1, assume that 1000 MW of UCAP will be provided in that auction if no new generation is built, and that the price of UCAP will be $5/kW-mo. But if the LSE sponsors entry of a new generator that can provide 100 MW of UCAP, the total amount of UCAP provided in the market will increase to 1100 MW and the price will fall to $4/kW-mo. Also assume that the net cost that the LSE will incur to build the generator is $6/kW-mo. × 100 MW = $600,000/mo., in which case that generator is not economically justified, because its $6/kW-mo. cost exceeds the $4/kW-mo. price of UCAP.

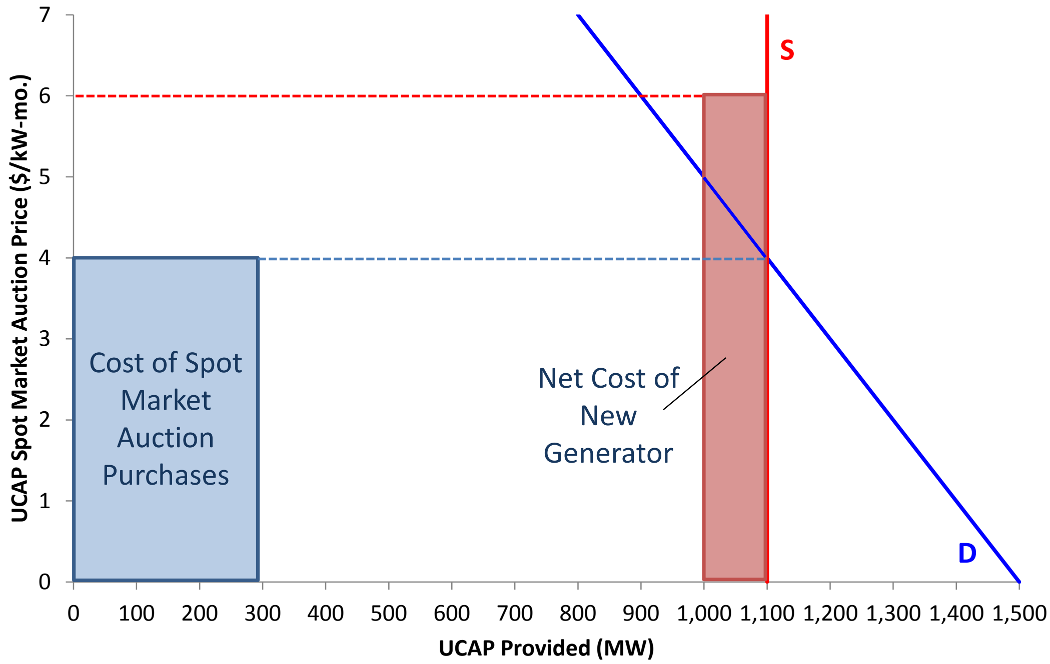
56. Since the LSE serves 35 percent of the load, it is responsible for 35 percent of the UCAP purchase obligation. If it does not sponsor entry of the new generator, it will need to purchase 35% × 1000 MW = 350 MW of UCAP in the SMA at a price of $5/kW-mo., for a total expenditure of $1,750,000, which is the area of the blue rectangle in Fig. 1.

Fig. 1: ICAP Costs in Scenario 1 if the LSE Does Not Sponsor Entry of the New Generator



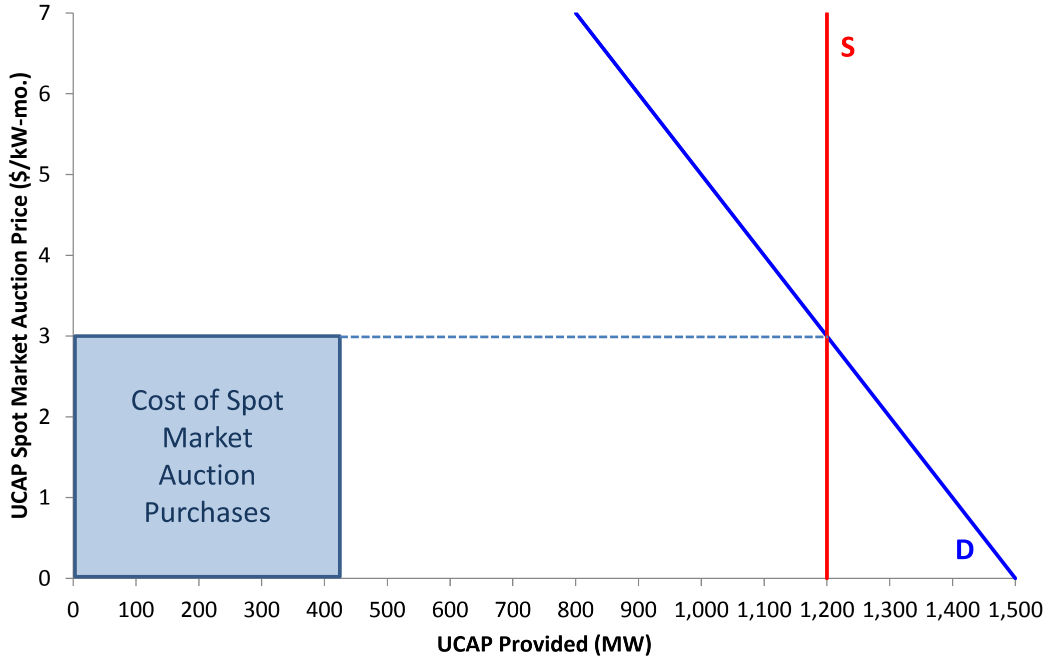
57. Alternatively, if the LSE sponsors entry of the new generator, its share of the UCAP purchase obligation will increase to 35% × 1100 MW = 385 MW, but it will only need to purchase 285 MW of UCAP in the SMA, as the other 100 MW of UCAP will be provided by the new generator. The cost of its SMA purchases therefore falls to 285 MW × $4/kW-mo. = $1,140,000, which is the area of the blue rectangle in Fig. 2. This is $610,000 less than its cost of SMA purchases when it does not sponsor entry. The LSE must pay the $600,000/mo. cost of the new generator, which is the area of the red rectangle in Fig. 2, but even so, it is still $10,000 better off. The uneconomic entry causes its monthly ICAP cost to decrease from $1,750,000 to $1,740,000, so, given these market conditions, it has an incentive to sponsor uneconomic entry.

Fig. 2: ICAP Costs in Scenario 1 if the LSE Sponsors Entry of the New Generator



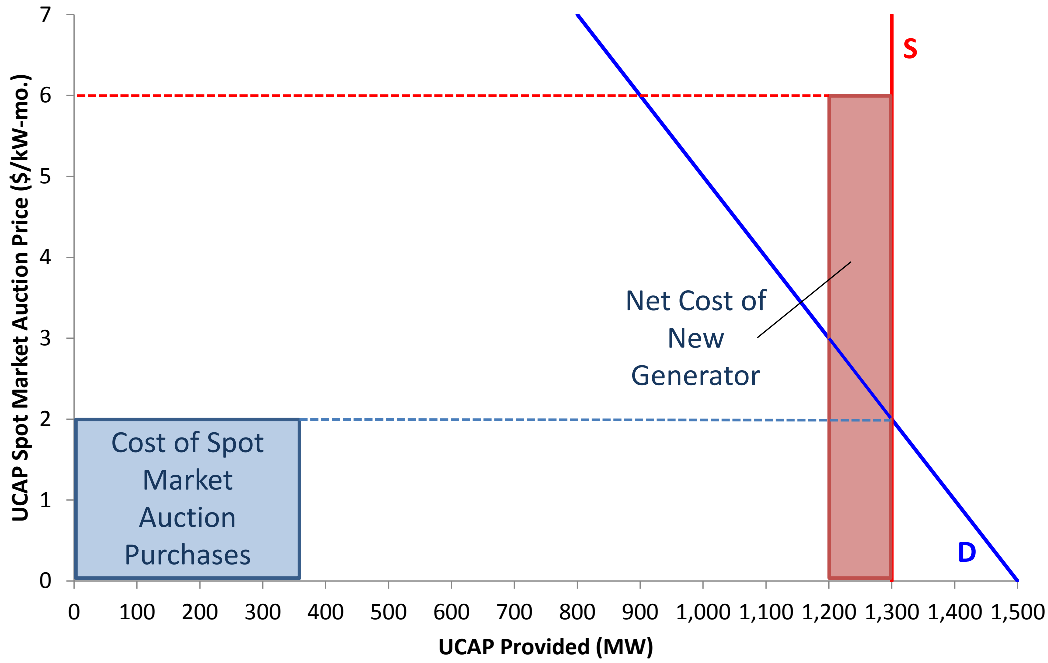
58. In Scenario 2, assume that if the new generator does not enter, 1200 MW of UCAP would be provided in the SMA at a price of $3/kW-mo.; while if the new generator were to enter, the total amount of UCAP provided in the auction would increase to 1300 MW and the price would fall to $2/kW-mo. In that case, the LSE would pay 35% × 1200 MW × $3/kW-mo. = $1,260,000 to purchase UCAP in the SMA, which is the area of the blue rectangle in Fig. 3, if it does not sponsor entry of the new generator.

Fig. 3: ICAP Costs in Scenario 2 if the LSE Does Not Sponsor Entry of the New Generator



59. Alternatively, if it sponsors entry of the new generator, it would pay (35% × 1300 MW – 100 MW) × $2/kW-mo. = $710,000 to purchase UCAP in the SMA, as shown by the area of the blue rectangle in Fig. 4, a $550,000 decrease. But the cost of the new generator is still $600,000. Therefore, the uneconomic entry now leaves it $50,000 worse off, as its total ICAP cost increases from $1,260,000 to $1,310,000. Given these market conditions, it does not have an incentive to sponsor uneconomic entry.

Fig. 4: ICAP Costs in Scenario 2 if the LSE Sponsors Entry of the New Generator



60. As these examples illustrate, since financial incentives for LSEs to sponsor uneconomic entry generally decrease as the competitive ICAP price decreases, the assessment of whether the SSE inadvertently provides offer floor exemptions to resources that would not otherwise receive them should assume that ICAP prices are relatively high.[37]

61. However, this assessment should also be limited to cases where the introduction of the SSE may permit resources to receive exemptions that they would not otherwise have been eligible to receive. As mentioned above, a new resource will pass the Part A test, and will therefore be exempt from offer floor mitigation, if the NYISO's

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[37] The analysis leading to this conclusion implicitly assumes that the LSE serves less than half of the load in a region and that the addition or removal of a certain amount of UCAP will have the same impact on UCAP prices no matter what the market conditions. These assumptions are honored in the analysis to follow, since the proposed maximum net short thresholds are developed under the assumption that an LSE that serves less than half of the load in a region, the relevant parts of the ICAP demand curves are straight lines, and the analysis assumes that supply is fixed.

forecast of the average ICAP price in the first year of the MSP at the location where that resource will provide ICAP is greater than the default net CONE, which is set at 75 percent of the net cost of developing the proxy generator for that location. Consequently, it is only necessary for the maximum net short analysis to consider situations where the ICAP revenue that a new generator would receive is less than or equal to default net CONE.

62. Since the SSE can award an offer floor mitigation exemption to a new resource that it would not otherwise receive occur only when that generator's ICAP revenue is less than or equal to default net CONE, and since the financial incentives for an LSE with a net short position to sponsor uneconomic entry are generally higher when competitive ICAP prices are higher, the maximum net short threshold analysis should assume that the ICAP market is at the point where the new resource would just qualify for an exemption under the Part A test.[38] If ICAP prices in the market were any higher, the SSE could not award a new resource an exemption that it would not have otherwise received because it would be eligible for an exemption under the Part A test; meanwhile, if prices in the market were any lower, incentives for LSE to subsidize uneconomic entry would also be lower, so the analysis would not be considering the case that provides the maximum incentive for LSEs to sponsor uneconomic entry.

63. On its website, the NYISO posts a detailed description of the procedures it uses to determine whether new resources are exempt from offer floor mitigation.[39]

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[38] Since the new resource will receive the ICAP price that would prevail after entry, this means that the maximum net short threshold will be defined in terms of the amount of UCAP the LSE is expected to purchase after entry of a new generator, not before.

[39] This description (the "BSM Narrative and Numerical Example") is available at http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mit

According to that description, if the sum of the forecasted monthly prices of UCAP over the year, after accounting for the impact of entry of the new resource on those prices, is at least equal to the default Net CONE for a region, the entry is exempt from offer floor mitigation under the Part A test.[40] Applying the procedure described therein, the default net CONE for G-J for the 2014-15 capability year is $80.02/kW-year.[41] Many combinations of summer and winter UCAP prices for G-J sum to $80.02/kW-year, but setting those prices at $9.72/kW-mo. in summer months and $3.61/kW-mo. in winter months also ensures that they are consistent with the assumption made in the ICAP demand curve study of the amount of ICAP that would be provided in G-J during the winter relative to the amount that would be provided during the summer.[42] Consequently, the analysis to follow will assume that following entry of the proxy generator, the G-J ICAP market clears at $9.72 per kW-mo. of UCAP in the summer and

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igation/Buyer_Side_Mitigation/Numerical_Example/BSM_Narrative_and_Numerical_Example%20March%207%202014.pdf.

[40] *Id.* at 7-9.

[41] Default net CONE is 75 percent of Mitigation Net CONE, and Mitigation Net CONE is equal to the annual revenue requirement for the proxy generator multiplied by one minus the ratio of (1) the assumed surplus ICAP level to (2) the amount of surplus ICAP at the "zero-crossing point," where the price of ICAP first reaches zero. In the NYISO's ICAP demand curve filing, it identified the annual revenue requirement for the proxy generator used for G-J as $117.67/kW-yr., while the zero-crossing point was 115% of the G-J ICAP requirement. (*New York Independent System Operator, Inc.*, Proposed Tariff Revisions to Implement Revised ICAP Demand Curves and a New ICAP Demand Curve for Capability Years 2014/2015, 2015/2016 and 2016/2017, and Request for Partial Phase-In and for Any Necessary Tariff Waivers, Docket No. ER14-500-000, and Unrelated Ministerial Tariff Correction at 31, Docket No. ER12-360-000 (filed Nov. 29, 2013) ("Demand Curve Filing").) Therefore, the default net CONE for G-J is 75% × $117.67 × (1 – 1.4% / 15%) = $80.02/kW-yr.

[42] Since the summer G-J UCAP price would have been $12.90/kW-mo. if the supply had been equal to the G-J UCAP requirement, declining to zero when supply is equal to 115 percent of the G-J UCAP requirement, it would have been $9.72/kW-mo. if the amount of surplus UCAP in G-J had been 15% × (1 – $9.72 / $12.90) = 3.69 percent of the G-J UCAP requirement. Then, since the ICAP demand curve for G-J was developed under the assumption that the amount of ICAP provided in G-J in the winter would be 1.0682 times the amount of ICAP provided in G-J in the summer, the corresponding winter surplus in G-J would have been 1.0369 × 1.0682 – 1 = 10.77% of the G-J UCAP requirement. At that level of surplus, the winter G-J UCAP price would have been $12.81 × (1 – 10.77% / 15%) = $3.61/kW-mo. (Appendix A contains the parameters used in this analysis that were taken from the NYISO's website.)

$3.61 per kW-mo. of UCAP in the winter, in which case the new generator would just be fully eligible for an exemption from offer floor mitigation.

Step 2: Cost of Sponsoring Entry in the LHV

64. Whether an LSE has an incentive to sponsor this entry will also depend on the cost of sponsoring entry by a new generator. As that cost increases, the overall cost that LSE will incur if it sponsors entry also increases, making it less likely that it will find sponsoring uneconomic entry to be in its financial interest. In the example presented in Paragraph 55 above, while the LSE had a financial incentive to sponsor entry of a generator whose net cost was $6/kW-mo., it would not have had a financial incentive to sponsor entry of a generator whose net cost was $7/kW-mo., as the $700,000 cost of the generator would have exceeded the $610,000 reduction in the cost of that LSE's UCAP purchases in the SMA. Simply put, while an LSE may have a financial interest in sponsoring an uneconomic resource, the lower the cost of that resource, the more likely it is to have such an interest.

65. The proxy generator for each region is the peaking generator that could be built at the lowest net cost in each of the three Localities and in the NYCA as a whole. Consequently, this analysis assesses whether an LSE would have a financial interest in sponsoring entry of the proxy generator for the relevant MCZ, since the cost of developing the proxy generator is less than the cost this LSE would incur to sponsor other peaking generators. While the proxy generator would be economic given the average market conditions assumed in the demand curve reset study, it would not be economic given the market conditions assumed for this maximum net short threshold analysis—*i.e.*,

that the amount of ICAP revenue provided by the market is 75 percent of default net CONE.

66. Table 1 illustrates the calculation of the average amount of ICAP revenue that the proxy generator used for G-J would have received during the 2014-15 capability year, if the amount of ICAP provided in G-J had been equal to 101.4 percent of the G-J ICAP requirement during the summer (*i.e.*, there was a 1.4 percent surplus), and the ratio of the amount of ICAP provided in G-J during the winter to the amount provided in G-J during the summer was 1.0682, in which case the amount of ICAP provided in G-J during the winter would have been 1.0682 × 101.4% = 108.3% of the G-J ICAP requirement (*i.e.*, there was an 8.3 percent surplus). These are the same assumptions that the NYISO made regarding the average amount of ICAP that would be provided in G-J when it performed the calculations underlying the currently effective ICAP demand curve for G-J. Since the reference price for the G-J ICAP demand curve in the 2014-15 capability year was $12.14/kW-mo.,[43] the price of ICAP in the summer and winter at the average levels of surplus ICAP assumed for the summer and winter would have been $11.01/kW-mo. and $5.41/kW-mo., respectively.[44] Consequently, given the amount of ICAP it could sell in each season (which is equal to its estimated DMNC for that season),[45] the proxy generator for G-J would have received ICAP payments of about $21,134,000 per year, implying that in combination with the net revenue this generator

[43] The calculations in this paragraph are done in terms of ICAP, rather than UCAP, because the demand curve reset study was performed in terms of ICAP.

[44] Given the G-J zero-crossing point of 115 percent of the G-J ICAP requirement, the price with a 1.4 percent surplus would be $12.14/kW-mo. × (1 – 1.4% / 15%) = $11.01/kW-mo., and the price with an 8.3 percent surplus would be $12.14/kW-mo. × (1 – 8.3% / 15%) = $5.41/kW-mo.

[45] Use of DMNCs is appropriate because the calculation is performed in terms of ICAP.

would receive from the sale of energy and ancillary services, an ICAP revenue stream averaging $21,134,000 per year would be sufficient to support entry under the market conditions assumed by the NYISO when it established the ICAP demand curve for G-J. This is the cost of entry that will be assumed in the analysis to follow.

Table 1: Average ICAP Payments Made to the G-J Proxy Generator

	Summer Months	Winter Months	Annual Total
ICAP Monthly Reference Pt. ($/kW-mo.)	12.14	12.14	
Assumed Surplus ICAP Level	101.4%	108.3%	
Zero-Crossing Point	115.0%	115.0%	
ICAP Rev. @ Assumed Surplus ($/kW-mo.)	11.01	5.41	
Seasonal DMNC (MW)	209.4	225.2	
ICAP Rev. @ Assumed Surplus ($000)	2,304	1,218	21,134

Step 3: Cost of Covering an LSE's Net Short Position If It Sponsors Uneconomic Entry in the LHV

67. Next, I will calculate the costs that an LSE serving 15 percent of the load in G-J (but no load in NYC) would incur to procure sufficient ICAP in the SMA if it sponsors entry of the G-J proxy generator and, after taking the ICAP provided by that generator into account, has a net short position equal to 7 percent of its UCAP purchase obligation for G-J (in both the summer and the winter). These calculations are summarized in Table 2.

Table 2: ICAP Costs for an LSE Serving 15 Percent of G-J Load that Sponsors Entry of the Proxy Generator and Has a 7 Percent Net Short Position

	Summer Months			Winter Months			Annual
	G-J	NYCA	Total	G-J	NYCA	Total	Total
LSE % of Forecasted Peak Load (MW)	15.00%	7.26%		15.00%	7.26%		
Total UCAP Obligation (MW)	13,993.4	37,473.0		15,045.0	39,956.6		
LSE UCAP Obligation (MW)	2,099.0	2,720.1		2,256.7	2,900.4		
UCAP Holdings Before SMA (MW)	1,952.1	2,573.1		2,098.8	2,742.4		
Net Short Pos'n Before SMA (MW)	146.9	146.9		158.0	158.0		
SMA UCAP Price ($/kW-mo.)	9.72	5.96		3.61	2.03		
Cost of SMA Purchases ($000/mo.)	1,429	0	1,429	571	(0)	571	11,997
Cost of Capacity from Proxy Gen. ($000/yr.)							21,134
Total Cost of Capacity ($000)							33,131

68. The preceding discussion of the market conditions to be assumed for this analysis concluded that following entry, the G-J UCAP price should be \$9.72/kW-mo. in the summer and \$3.61/kW-mo. in the winter. The overall G-J UCAP purchase obligations during the 2014-15 capability year that correspond to those prices are 13,993.4 MW in summer months and 15,045.0 MW in winter months,[46] so the LSE's share of the overall G-J UCAP purchase obligation is 15% × 13,993.4 MW = 2,099.0 MW in summer months and 15% × 15,045.0 MW = 2,256.7 MW in winter months, and its net short position with regard to that UCAP purchase obligation is 7% × 2,099.0 MW = 146.9 MW in summer months and 7% × 2,256.7 MW = 158.0 MW in winter months. Therefore, the total amount the LSE pays for G-J UCAP purchased in the SMA is 146.9 MW × \$9.72/kW-mo. = \$1,429,000 in each summer month, and 158.0 MW × \$3.61/kW-mo. = \$571,000 in each winter month, which sum to \$11,997,000 annually.

69. In addition, given the nested structure of the NYISO's ICAP market, this LSE will have an obligation to purchase additional capacity, equal to the difference between its shares of the NYCA and G-J UCAP purchase obligations, which can be met using ROS capacity. If this LSE serves 15 percent of load in G-J, then it serves about 7.26 percent of load in the NYCA as a whole.[47] During the 2014-15 capability year, the overall NYCA UCAP purchase obligation averaged 37,473.0 MW in the summer and

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[46] In the summer, the UCAP reference price for G-J was \$12.90/kW-mo., while the UCAP requirement was 13,494.9 MW. Therefore, given that the zero-crossing point for G-J was 115 percent of the minimum UCAP requirement, the quantity of UCAP that corresponds to a price of \$9.72/kW-mo. is (1 + 15% × (1 – \$9.72 / \$12.90)) × 13,494.9 MW = 13,993.4 MW. In the winter, the UCAP reference price for G-J was \$12.81/kW-mo., while the UCAP requirement was 13,582.3 MW. Therefore, the quantity of UCAP that corresponds to a price of \$3.61/kW-mo. is (1 + 15% × (1 – \$3.61 / \$12.81)) × 13,582.3 MW = 15,045.0 MW.

[47] An LSE that serves 15 percent of G-J load serves about 15% × (16,291.4 MW / 33,665.7 MW) = 7.26% of NYCA load, because the forecasted peak loads for G-J and the NYCA for summer 2014 were 16,291.4 MW and 33,665.7 MW, respectively.

39,956.6 MW in the winter, so this LSE's share of that overall NYCA UCAP purchase obligation was 7.26% × 37,473.0 MW = 2,720.1 MW in the summer, which is 621.1 MW more than its share of the G-J UCAP purchase obligation in the summer, and its share of the overall NYCA UCAP purchase obligation is 7.26% × 39,956.6 MW = 2,900.4 MW in the winter, which is 643.6 MW more than its share of the overall G-J UCAP purchase obligation in the winter. For the purposes of this calculation, I assume that this LSE already holds just enough ROS UCAP to meet the difference between its share of the NYCA and G-J UCAP purchase obligations, after entry of the new generator.[48] Therefore, it does not incur any additional cost to purchase ROS UCAP in the SMA.

70. Taking into account the annual cost of sponsoring the entry of new capacity, which was calculated as $21,134,000 in Table 1, the total cost incurred by this LSE to procure ICAP to cover its net short position is $33,131,000 per year.

Step 4: Cost of Covering an LSE's Net Short Position If It Does Not Sponsor Uneconomic Entry in the LHV

71. Table 3 illustrates the costs that this LSE would incur to purchase ICAP in the SMA if it does not sponsor entry of the proxy generator.

72. Not building the new generator affects the LSE's net short position in two ways. First, the LSE's overall UCAP holdings fall by the amount of UCAP the proxy generator would have provided, which would have been about 204.8 MW of UCAP in the summer and 220.4 MW of UCAP in the winter.[49]

[48] This assumption (and similar assumptions made in subsequent calculations of maximum net short thresholds) will not affect the results of the comparison of the amount this LSE pays for ICAP if it sponsors entry of new generation to the costs it incurs if it does not sponsor entry.

[49] Its DMNC is 209.4 MW in the summer and 225.2 MW in the winter, while its expected EFORd is 2.17 percent. Therefore, it provides 209.4 × (1 – 0.0217) = 204.8 MW of UCAP in the summer and 225.2 × (1 – 0.0217) = 220.4 MW of UCAP in the winter.

73. However, there is another, partially offsetting effect. LSEs are responsible for their respective shares of UCAP purchase obligations, so, as the illustrative example above showed, if the entry of a generator increases the total amount of UCAP purchased, it will also increase the amount of UCAP that each LSE is required to procure. Similarly, not building the new generator will reduce the overall G-J UCAP purchase obligation, relative to the scenario presented above which assumed that the generator was built, and will therefore reduce the LSE's share of the G-J UCAP purchase obligation.

74. For the purposes of this analysis, I assume that the overall UCAP purchase obligation for G-J falls by the amount of UCAP that new generator would have provided. In that case, the G-J UCAP purchase obligation in this scenario will be 13,993.4 MW – 204.8 MW = 13,788.6 MW in summer months and 15,045.0 MW – 220.4 MW = 14,824.6 MW in winter months; and the LSE's share of that purchase obligation will fall correspondingly, to 15% × 13,788.6 MW = 2,068.3 MW in summer months and 15% × 14,824.6 MW = 2,223.7 MW in winter months. As Table 2 reported, in the scenario in which the new generator entered, this LSE's share of the G-J UCAP purchase obligation was 2,099.0 MW in summer months and 2,256.7 MW in winter months, so its share of the G-J UCAP purchase obligation during the summer has fallen by 30.7 MW, and its share of the G-J UCAP purchase obligation during the winter has fallen by 33.1 MW, relative to the scenario with entry.

Table 3: ICAP Costs for the Same LSE as Table 2
If It Does Not Sponsor Entry of the Proxy Generator

	Summer Months			Winter Months			Annual
	G-J	NYCA	Total	G-J	NYCA	Total	Total
LSE % of Forecasted Peak Load (MW)	15.00%	7.26%		15.00%	7.26%		
UCAP from Proxy Generator (MW)	204.8	204.8		220.4	220.4		
Total UCAP Obligation (MW)	13,788.6	37,473.0		14,824.6	39,956.6		
LSE UCAP Obligation (MW)	2,068.3	2,720.1		2,223.7	2,900.4		
UCAP Holdings Before SMA (MW)	1,747.2	2,368.3		1,878.4	2,522.0		
Net Short Pos'n Before SMA (MW)	321.0	351.8		345.3	378.3		
SMA UCAP Price ($/kW-mo.)	11.03	5.96		5.00	2.03		
Cost of SMA Purchases ($000/mo.)	3,541	183	3,724	1,726	67	1,793	33,101

75. Taking this impact on the LSE's share of UCAP purchase obligations into account, the LSE's net short position with regard to its G-J UCAP purchase obligation, which was 146.9 MW in the summer and 158.0 MW in the winter in the scenario with entry, increases to 146.9 MW + 204.8 MW – 30.7 MW = 321.0 MW in summer months and 158.0 MW + 220.4 MW – 33.1 MW = 345.3 MW in winter months. The reduction in the total amount of UCAP sold in G-J also causes the G-J UCAP price to be higher than in the scenario with entry. It rises to $11.03/kW-mo. in the summer and $5.00/kW-mo. in the winter.[50] Therefore, the total amount the LSE pays for G-J UCAP purchased in the SMA is 321.0 MW × $11.03/kW-mo. = $3,541,000 in each summer month, and 345.3 MW × $5.00/kW-mo. = $1,726,000 in each winter month.

76. In addition, the LSE will now have a net short position in the ROS market. In the scenario in which the new generator entered, I assumed that the LSE had just enough ROS UCAP to offset the difference between its NYCA and G-J UCAP purchase

[50] In the scenario with entry, the G-J UCAP price was $9.72/kW-mo. in the summer and $3.61/kW-mo. in the winter. Given the summer 2014 monthly reference point of $12.90/kW-mo. and the UCAP requirement for summer 2014 of 13,494.9 MW, a reduction of 204.8 MW in the amount of UCAP supplied during the summer would have caused the price of UCAP to increase by $12.90/kW-mo. × (204.8 MW / (15% × 13,494.9 MW)) = $1.31/kW-mo., to $11.03/kW-mo. Given the winter 2014-15 monthly reference point of $12.81/kW-mo. and the UCAP requirement for winter 2014-15 of 13,582.3 MW, a reduction of 220.4 MW in the amount of UCAP supplied during the winter would have caused the price of UCAP to increase by $12.81/kW-mo. × (220.4 MW / (15% × 13,582.3 MW)) = $1.39/kW-mo., to $5.00/kW-mo.

obligations. However, while its share of the G-J UCAP purchase obligation is 30.7 MW lower during the summer and 33.1 MW lower during the winter than in the scenario in which the new generator enters, its share of the overall NYCA purchase obligation remains the same. That means that it must purchase 30.7 MW of ROS UCAP in the summer and 33.1 MW of ROS UCAP in the winter. The price of ROS UCAP averaged $5.96/kW-mo. in the summer 2014 capability period and $2.03/kW-mo. in the winter 2014-15 capability period. Therefore, its cost of purchasing ROS UCAP is 30.7 MW × $5.96/kW-mo. = $183,000 in each summer month, and 33.1 MW × $2.03/kW-mo. = $67,000 in each winter month. Added to the costs of purchasing G-J UCAP in the SMA, this LSE's total annual cost of purchasing UCAP in the SMA is $33,101,000, which is slightly less than the $33,131,000 cost this LSE would have incurred if it had sponsored entry of the new generator, as calculated in Table 2.

Step 5: Maximum Net Short Thresholds for LSEs Serving Different Shares of G-J Load

77. Consequently, it is not in this LSE's interest to sponsor entry of an uneconomic new generator. While doing so would cause the price of G-J UCAP in the SMA to fall from $11.03/kW-mo. in the summer and $5.00/kW-mo. in the winter to $9.72/kW-mo. in the summer and $3.61/kW-mo. in the winter, the cost of subsidizing uneconomic entry more than offsets the impact of these price reductions on the LSE's cost of purchasing ICAP in the SMA.

78. However, if this LSE's net short position had increased slightly, from 7 percent of its UCAP purchase obligation for G-J to 7.5 percent, it would have been in its financial interest to sponsor entry of that generator, as the amount it pays for ICAP would have been lower if it had sponsored entry than if it had not. Due to this increase in its net

short position, it would have purchased a larger amount of UCAP in the SMA, and therefore would have reaped a greater benefit from the price suppression caused by uneconomic entry. Therefore, the maximum net short position (rounded to the nearest half percent) for an LSE that serves 15 percent of load in G-J that does not give it an incentive to subsidize uneconomic entry is 7 percent of its UCAP purchase obligation for G-J.

79. The left side of Table 4 summarizes the largest net short positions (after entry), in increments of 0.5 percent of an LSE's share of the G-J UCAP purchase obligations, that LSEs serving load in G-J (but not in NYC) can have without having an incentive to sponsor uneconomic entry. For example, it shows that an LSE with a 5 percent load share in G-J can have a net short position equal to 12.5 percent of its G-J UCAP purchase obligation without having an incentive to sponsor uneconomic entry, because its annual ICAP costs will be $28,275,000 if it sponsors uneconomic entry and $28,263,000 if it does not. Meanwhile, the right side of Table 4 shows that if the net short positions had been slightly higher, the LSE could have reduced its ICAP costs by sponsoring entry of that generator. If an LSE with a 5 percent load share in G-J had a net short position of 13 percent of its UCAP obligation after taking the impact of the new generator into account, its ICAP cost would have been slightly lower if it had sponsored entry.

80. Therefore, if an LSE serves 5 percent of G-J load or less, its maximum net short threshold is set at 12.5 percent of its anticipated share of the G-J UCAP purchase obligation, because if its net short position is not more than 12.5 percent of its share of the G-J UCAP purchase obligation (after entry), it would not have an incentive to sponsor

uneconomic entry. Consequently, if an LSE sponsors a resource in the LHV, and following entry, its net short position is less than 12.5 percent of its anticipated share of the G-J UCAP purchase obligation, that resource would be fully eligible for the SSE.

Table 4: Maximum Net Short Thresholds for Entry in the LHV

LSE's Share of G-J Load	Max. Net Short Threshold as % of LSE's G-J UCAP Obligation	ICAP Procurement Costs ($000/yr.)		Slightly Larger Net Short Position	ICAP Procurement Costs ($000/yr.)	
		With Entry	Without Entry		With Entry	Without Entry
5%	12.5%	28,275	28,263	13.0%	28,561	28,607
10%	8.0%	30,275	30,166	8.5%	30,846	30,854
15%	7.0%	33,131	33,101	7.5%	33,988	34,134
20%	6.0%	34,845	34,659	6.5%	35,987	36,036
30%	5.5%	39,986	39,841	6.0%	41,700	41,907

81. The maximum net short threshold decreases as the share of load served by the LSE increases. A resource in the LHV that is sponsored by an LSE that serves more than 5 percent but no more than 10 percent of G-J load would only be fully eligible for the SSE if that LSE's net short position is no more than 8 percent of its anticipated G-J UCAP purchase obligation; a resource in the LHV that is sponsored by an LSE that serves more than 10 percent but no more than 15 percent of G-J load would only be fully eligible for the SSE if that LSE's net short position is no more than 7 percent of its anticipated G-J UCAP purchase obligation; a resource in the LHV that is sponsored by an LSE that serves more than 15 percent but no more than 20 percent of G-J load would only be fully eligible for the SSE if that LSE's net short position is no more than 6 percent of its anticipated G-J UCAP purchase obligation; and a resource in the LHV that is sponsored by an LSE that serves more than 20 percent but no more than 30 percent of G-J load would only be fully eligible for the SSE if that LSE's net short position is no more than 5.5 percent of its anticipated G-J UCAP purchase obligation. LSEs that serve more than 30 percent of load in the LHV would have a maximum net short threshold set

to the threshold that would be calculated for an LSE that serves 30 percent of load in the LHV.[51]

Maximum Net Short Threshold for Entry in NYC

82. The analysis of the maximum net short threshold for an LSE that is developing a new resource in NYC will focus on the effect that entry of an uneconomic resource would have on the amount paid for ICAP by an LSE that serves load in NYC, since those LSEs purchase much of their ICAP from resources in NYC and may therefore have a financial incentive to sponsor uneconomic entry that would suppress the NYC ICAP price below competitive levels. However, the degree to which such an LSE has a financial incentive to suppress NYC ICAP prices will depend upon whether that LSE also serves load in the LHV, since entry in NYC can affect not only the NYC price, but also the G-J price. Consequently, the analysis to follow calculates two different sets of values for the maximum net short thresholds to be applied to LSEs seeking to develop a resource in NYC. One set applies to LSEs serving load in NYC only, while the other applies to LSEs serving load in NYC and in the LHV. In each case, the analysis calculates how the entry of an uneconomic generator would affect the amount paid for ICAP by an LSE, both in NYC and elsewhere in G-J, and how that effect changes as the amount of load served by that LSE changes.

[51] For example, if the overall UCAP obligation for G-J is expected to average 14,500 MW over the course of the year, the maximum net short threshold for an LSE serving 30 percent of the load in G-J would be 5.5% × 30% × 14,500 MW = 239 MW. Consequently, the maximum net short threshold for LSEs serving more than 30 percent of the load in G-J also would be 239 MW.

Step 1: Market Conditions at Which the Impact of New Generation in NYC Will Be Assessed

83. For the same reasons as given above, the maximum net short threshold analysis for NYC should assume that ICAP markets in NYC and G-J are at the point where the new resource would just qualify for exemption under the Part A test. The preceding section established that G-J UCAP prices of \$9.72/kW-mo. of UCAP in the summer and \$3.61/kW-mo. of UCAP in the winter would produce revenue equal to the default net CONE for G-J.

84. Using the procedure described in the BSM Narrative and Numerical Example, the default net CONE for NYC for the 2014-15 capability year is \$117.10/kW-year.[52] Once more, many combinations of summer and winter UCAP prices for NYC sum to \$117.10/kW-year, but setting those prices at \$14.73/kW-mo. in summer months and \$4.78/kW-mo. in winter months also ensures that they are consistent with the assumption made in the ICAP demand curve study of the amount of ICAP that would be provided in NYC during the winter relative to the amount that would be provided during the summer.[53] Consequently, the analysis to follow will assume that following entry of the proxy generator, the NYC market clears at \$14.73 per kW-mo. of UCAP in the summer and \$4.78 per kW-mo. of UCAP in the winter.

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[52] In the Demand Curve Filing, the NYISO identified the annual revenue requirements for the proxy generator used for NYC as \$175.65/kW-yr., while the zero-crossing point was 118% of the NYC ICAP requirement. (Demand Curve Filing at 31.) Therefore, the default net CONE for NYC is 75% × \$175.65 × (1 – 2% / 18%) = \$117.10/kW-yr.

[53] Since the summer NYC UCAP price is \$19.62/kW-mo. at the NYC UCAP requirement, declining to zero at 118 percent of the NYC UCAP requirement, it would be \$14.73/kW-mo. if the amount of surplus UCAP in NYC was 18% × (1 – \$14.73 / \$19.62) = 4.48 percent of the NYC UCAP requirement. Then, since the ICAP demand curve for NYC was developed under the assumption that the amount of ICAP provided in NYC in the winter would be 1.0872 times the amount of ICAP provided in NYC in the summer, the corresponding winter surplus in NYC would be 1.0448 × 1.0872 – 1 = 13.60% of the NYC UCAP requirement. At that level of surplus, the winter NYC UCAP price would be \$19.54 × (1 – 13.60% / 18%) = \$4.78/kW-mo.

Step 2: Cost of Sponsoring Entry in NYC

85. Table 5 illustrates the calculation of the average amount of ICAP revenue that the proxy generator used for NYC would have received during the 2014-15 capability year, if the amount of ICAP provided in NYC had been equal to 102 percent of the NYC ICAP requirement during the summer (*i.e.*, there was a 2 percent surplus), and the ratio of the amount of ICAP provided in NYC during the winter to the amount provided in NYC during the summer was 1.0872, in which case the amount of ICAP provided in NYC during the winter would have been 1.0872 × 101.4% = 110.9% of the NYC ICAP requirement (*i.e.*, there was a 10.9 percent surplus). These are the same assumptions that the NYISO made when the NYISO when it performed the calculations underlying the currently effective ICAP demand curve for NYC. Since the reference price for the NYC ICAP demand curve in the 2014-15 capability year was $18.55/kW-mo.,[54] the price of ICAP in the summer and winter at the average levels of surplus ICAP assumed for the summer and winter would have been $16.49/kW-mo. and $7.32/kW-mo., respectively.[55] Consequently, given the amount of ICAP it could sell in each season (which is equal to its estimated DMNC for that season), the proxy generator for NYC would have received ICAP payments of about $30,474,000 per year, implying that in combination with the net revenue this generator would receive from the sale of energy and ancillary services, an ICAP revenue stream averaging $30,474,000 per year would be sufficient to support entry under the market conditions assumed by the NYISO when it

[54] As was the case when calculating the net cost of the proxy generator for G-J, the calculations in this paragraph are done in terms of ICAP, rather than UCAP, since the demand curve reset study was performed in terms of ICAP.

[55] Given the NYC zero-crossing point of 118 percent of the NYC ICAP requirement, the price with a 2 percent surplus would be $18.55/kW-mo. × (1 – 2% / 18%) = $16.49/kW-mo., and the price with a 10.9 percent surplus would be $18.55/kW-mo. × (1 – 10.9% / 18%) = $7.32/kW-mo.

established the ICAP demand curve for NYC. This is the cost of entry that will be assumed in the analysis to follow.

Table 5: Average ICAP Payments Made to the NYC Proxy Generator

	Summer Months	Winter Months	Annual Total
ICAP Monthly Reference Pt. ($/kW-mo.)	18.55	18.55	
Assumed Surplus ICAP Level	102.0%	110.9%	
Zero-Crossing Point	118.0%	118.0%	
ICAP Rev. @ Assumed Surplus ($/kW-mo.)	16.49	7.32	
Seasonal DMNC (MW)	208.8	223.6	
ICAP Rev. @ Assumed Surplus ($000)	3,442	1,637	30,474

86. Next, I will calculate the costs that an LSE would incur to procure sufficient ICAP in the SMA to cover its net short position. Since these costs depend on whether the LSE serves load in the LHV, I will first go through Steps 3 through 5 under the assumption that the LSE serves load in NYC but not in the LHV. This analysis will culminate in a set of maximum net short thresholds that would apply to such an LSE if it were to seek an SSE for a new generator it was sponsoring in NYC. Then I will proceed to consideration of an LSE that serves load in both NYC and the LHV, ultimately concluding with a set of maximum net short thresholds that would apply to it if it were to seek an SSE for such a generator.

<u>Thresholds for LSEs That Do Not Serve Load in the LHV</u>

Step 3: Cost of Covering an LSE's Net Short Position If It Sponsors Uneconomic Entry in NYC (if that LSE Does Not Serve Load in the LHV)

87. Initially, I will assume this LSE serves 15 percent of the load in NYC but no load in the LHV. Even so, since NYC is part of G-J, it serves about 10.85 percent of

load in G-J,[56] so it is responsible for meeting 10.85 percent of the G-J UCAP purchase obligation (although NYC UCAP counts towards its G-J obligation). These calculations, which are summarized in Table 6, assume that this LSE sponsors entry of the proxy generator in NYC and, after taking the ICAP provided by that generator into account, has a net short position equal to 5 percent of its UCAP purchase obligation for NYC (in both the summer and the winter).

Table 6: ICAP Costs for an LSE Serving 15 Percent of NYC Load that Sponsors Entry of the Proxy Generator and Has a 5 Percent Net Short Position

	Summer Months				Winter Months				Annual
	NYC	G-J	NYCA	Total	NYC	G-J	NYCA	Total	Total
LSE % of Forecasted Peak Load (MW)	15.00%	10.85%	5.25%		15.00%	10.85%	5.25%		
Total UCAP Obligation (MW)	9,895.1	13,993.4	37,473.0		10,801.1	15,045.0	39,956.6		
LSE UCAP Obligation (MW)	1,484.3	1,518.1	1,967.3		1,620.2	1,632.2	2,097.7		
UCAP Holdings Before SMA (MW)	1,410.1	1,410.1	1,859.2		1,539.2	1,539.2	2,004.7		
Net Short Pos'n Before SMA (MW)	74.2	108.1	108.1		81.0	93.0	93.0		
SMA UCAP Price ($/kW-mo.)	14.73	9.72	5.96		4.78	3.61	2.03		
Cost of SMA Purchases ($000/mo.)	1,093	329	-	1,422	388	43	-	431	11,121
Cost of Capacity from Proxy Gen. ($000/yr.)									30,474
Total Cost of Capacity ($000)									41,595

88. The discussion of the market conditions to be assumed for this analysis concluded that following entry, the NYC UCAP price should be \$14.73/kW-mo. in the summer and \$4.78/kW-mo. in the winter. The overall NYC UCAP purchase obligations during the 2014-15 capability year that correspond to those prices are 9,895.1 MW in summer months and 10,801.1 MW in winter months,[57] so the LSE's share of the overall NYC UCAP purchase obligation is 15% × 9,895.1 MW = 1,484.3 MW in summer

[56] An LSE that serves 15 percent of NYC load serves about 15% × (11,782.8 MW / 16,291.4 MW) = 10.85% of G-J load, because the forecasted peak loads for NYC and G-J for summer 2014 were 11,782.8 MW and 16,291.4 MW, respectively.

[57] In the summer, the UCAP reference price for NYC was \$19.62/kW-mo., while the UCAP requirement was 9,470.5 MW. Therefore, given that the zero-crossing point for NYC was 118 percent of the minimum UCAP requirement, the quantity of UCAP that corresponds to a price of \$14.73/kW-mo. is (1 + 18% × (1 – \$14.73 / \$19.62)) × 9,470.5 MW = 9,895.1 MW. In the winter, the UCAP reference price for NYC was \$19.54/kW-mo., while the UCAP requirement was 9,508.6 MW. Therefore, the quantity of UCAP that corresponds to a price of \$4.78/kW-mo. is (1 + 18% × (1 – \$4.78 / \$19.54)) × 9,508.6 MW = 10,801.1 MW.

months and 15% × 10,801.1 MW = 1,620.2 MW in winter months, and its net short position with regard to that UCAP purchase obligation is 5% × 1,484.3 MW = 74.2 MW in summer months and 5% × 1,620.2 MW = 81.0 MW in winter months. Therefore, the total amount the LSE pays for NYC UCAP purchased in the SMA is 74.2 MW × $14.73/kW-mo. = $1,093,000 in each summer month, and 81.0 MW × $4.78/kW-mo. = $388,000 in each winter month.

89. This LSE will also have an obligation to purchase a certain amount of UCAP in G-J. The difference between its shares of the G-J and NYC UCAP purchase obligations can be met using G-J UCAP. The discussion of market conditions concluded that following entry, the G-J UCAP price should be $9.72/kW-mo. in the summer and $3.61/kW-mo. in the winter. At those prices, overall G-J UCAP purchase obligations during the 2014-15 capability year would have been 13,993.4 MW in summer months and 15,045.0 MW in winter months,[58] so this LSE's share of the overall G-J UCAP purchase obligation in summer months would have been 10.85% × 13,993.4 MW = 1,518.1 MW, which is 33.8 MW larger than its 1,484.3 MW share of the overall NYC UCAP purchase obligation in the summer, and its share of the overall G-J purchase obligation in winter months would have been 10.85% × 15,045.0 MW = 1,632.2 MW, which is 12.0 MW larger than its 1,620.2 MW share of the overall NYC UCAP purchase obligation in the winter. It must purchase the difference between its share of the G-J and NYC UCAP purchase obligations at G-J prices, so the total amount the LSE pays for G-J UCAP purchased in the SMA is 33.8 MW × $9.72/kW-mo. = $329,000 in each summer month, and 12.0 MW × $3.61/kW-mo. = $43,000 in each winter month.

[58] *See* note 46 *supra*.

90. Finally, this LSE will also have an additional obligation to purchase capacity equal to the difference between its shares of the NYCA and G-J UCAP purchase obligations, which can be met using ROS UCAP. If this LSE serves 15 percent of load in NYC, then it serves about 5.25 percent of load in the NYCA as a whole.[59] During the 2014-15 capability year, the overall NYCA UCAP purchase obligation averaged 37,473.0 MW in the summer and 39,956.6 MW in the winter, so this LSE's share of that overall NYCA purchase obligation was 5.25% × 37,473.0 MW = 1,967.3 MW in the summer, which is 449.2 MW more than its 1,518.1 MW share of the overall G-J UCAP purchase obligation in the summer, and its share of the overall NYCA purchase obligation is 5.25% × 39,956.6 MW = 2,097.7 MW in the winter, which is 465.5 MW more than its 1,632.2 MW share of the overall G-J UCAP purchase obligation in the winter. For the purposes of this calculation, I assume that this LSE already holds sufficient ROS UCAP to meet this difference between its share of the NYCA and G-J UCAP purchase obligations. Therefore, it does not incur any additional cost to purchase ROS UCAP in the SMA.

91. Taking into account the annual cost of sponsoring the entry of new capacity, which was calculated as $30,474,000 in Table 5, the total cost incurred by this LSE to procure ICAP to cover its net short position is $41,595,000 per year.

[59] An LSE that serves 15 percent of NYC load serves about 15% × (11,782.8 MW / 33,665.7 MW) = 5.25% of NYCA load, because the forecasted peak loads for NYC and the NYCA for summer 2014 were 11,782.8 MW and 33,665.7 MW, respectively.

Step 4: Cost of Covering an LSE's Net Short Position If It Does Not Sponsor Uneconomic Entry in NYC (if that LSE Does Not Serve Load in the LHV)

92. Table 7 illustrates the costs that this LSE would incur to purchase ICAP in the SMA if it does not sponsor entry of the proxy generator in NYC.

93. Once more, not building the new generator affects the LSE's net short position in two ways. The LSE's overall UCAP holdings fall by the amount of UCAP the proxy generator would have provided, which would have been about 204.2 MW of UCAP in the summer and 218.7 MW of UCAP in the winter.[60] But not building the new generator will reduce the overall NYC and G-J UCAP purchase obligations, relative to the scenario presented above which assumed that the generator was built, which will therefore reduce the LSE's share of those UCAP purchase obligations.

94. Assuming that the overall UCAP purchase obligation for NYC falls by the amount of UCAP that new generator would have provided, the NYC UCAP purchase obligation in this scenario would be 9,895.1 MW – 204.2 MW = 9,690.9 MW in summer months and 10,801.1 MW – 218.7 MW = 10,582.4 MW in winter months. The LSE's share of that purchase obligation would fall correspondingly, to 15% × 9,690.9 MW = 1,453.6 MW in summer months and 15% × 10,582.4 MW = 1,587.4 MW in winter months. As Table 6 reported, in the scenario in which the new generator entered, this LSE's share of the NYC UCAP purchase obligation was 1,484.3 MW in summer months and 1,620.2 MW in winter months, so its share of the NYC UCAP purchase obligation

[60] These are slightly lower than the corresponding figures presented for the proxy generator in the LHV, because the DMNCs are slightly lower in NYC. The NYC proxy generator's DMNC is 208.8 MW in the summer and 223.6 MW in the winter. Its expected EFORd remains 2.17 percent. Therefore, it provides 208.8 × (1 – 0.0217) = 204.2 MW of UCAP in the summer and 223.6 × (1 – 0.0217) = 218.7 MW of UCAP in the winter.

during the summer has fallen by 30.6 MW, and its share of the NYC UCAP purchase obligation during the winter has fallen by 32.8 MW, relative to the scenario with entry.

95. Similarly, assuming that the overall UCAP purchase obligation for G-J falls by the amount of UCAP that new generator would have provided, the G-J UCAP purchase obligation in this scenario would be 13,993.4 MW – 204.2 MW = 13,789.2 MW in summer months and 15,045.0 MW – 218.7 MW = 14,826.2 MW in winter months. The LSE's share of that purchase obligation would fall correspondingly, to 10.85% × 13,789.2 MW = 1,496.0 MW in summer months and 10.85% × 14,826.2 MW = 1,608.5 MW in winter months. As Table 6 reported, in the scenario in which the new generator entered, this LSE's share of the G-J UCAP purchase obligation was 1,518.1 MW in summer months and 1,632.2 MW in winter months, so its share of the G-J UCAP purchase obligation during the summer has fallen by 22.2 MW, and its share of the G-J UCAP purchase obligation during the winter has fallen by 23.7 MW, relative to the scenario with entry.

Table 7: ICAP Costs for the Same LSE as Table 6
If It Does Not Sponsor Entry of the Proxy Generator

	Summer Months				Winter Months				Annual
	NYC	G-J	NYCA	Total	NYC	G-J	NYCA	Total	Total
LSE % of Forecasted Peak Load (MW)	15.00%	10.85%	5.25%		15.00%	10.85%	5.25%		
UCAP from Proxy Generator (MW)	204.2	204.2	204.2		218.7	218.7	218.7		
Total UCAP Obligation (MW)	9,690.9	13,789.2	37,473.0		10,582.4	14,826.2	39,956.6		
LSE UCAP Obligation (MW)	1,453.6	1,496.0	1,967.3		1,587.4	1,608.5	2,097.7		
UCAP Holdings Before SMA (MW)	1,205.8	1,205.8	1,655.0		1,320.4	1,320.4	1,785.9		
Net Short Pos'n Before SMA (MW)	247.8	290.1	312.3		266.9	288.0	311.8		
SMA UCAP Price ($/kW-mo.)	17.08	11.02	5.96		7.28	4.99	2.03		
Cost of SMA Purchases ($000/mo.)	4,233	467	132	4,832	1,944	105	48	2,097	41,575

96. Taking this impact on the LSE's share of UCAP purchase obligations into account, the LSE's net short position with regard to its NYC UCAP purchase obligation, which was 74.2 MW in the summer and 81.0 MW in the winter in the scenario with entry, increases to 74.2 MW + 204.2 MW – 30.6 MW = 247.8 MW in summer months

and 81.0 MW + 218.7 MW – 32.8 MW = 266.9 MW in winter months. The reduction in the total amount of UCAP sold in NYC also causes the NYC UCAP price to be higher than in the scenario with entry. It rises to \$17.08/kW-mo. in the summer and \$7.28/kW-mo. in the winter.[61] Therefore, the total amount the LSE pays for NYC UCAP purchased in the SMA is 247.8 MW × \$17.08/kW-mo. = \$4,233,000 in each summer month, and 266.9 MW × \$7.28/kW-mo. = \$1,944,000 in each winter month.

97. The LSE's net short position with regard to its G-J UCAP purchase obligation, which was 108.1 MW in the summer and 93.0 MW in the winter in the scenario with entry, also increases, to 108.1 MW + 204.2 MW – 22.2 MW = 290.1 MW in summer months and 93.0 MW + 218.7 MW – 23.7 MW = 288.0 MW in winter months. The reduction in the total amount of UCAP sold in G-J causes the G-J UCAP price to be higher than in the scenario with entry; it rises to \$11.02/kW-mo. in the summer and \$4.99/kW-mo. in the winter.[62] But the LSE only pays the G-J price for the amount by which its net short position in G-J exceeds its net short position in NYC, which is 290.1 MW – 247.8 MW = 42.3 MW in the summer and 288.0 MW – 266.9 MW

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[61] In the scenario with entry, the NYC UCAP price was \$14.73/kW-mo. in the summer and \$4.78/kW-mo. in the winter. Given the summer 2014 monthly reference point for NYC of \$19.62/kW-mo. and the NYC UCAP requirement for summer 2014 of 9,470.5 MW, a reduction of 204.2 MW in the amount of UCAP supplied during the summer would have caused the price of NYC UCAP to increase by \$19.62/kW-mo. × (204.2 MW / (18% × 9,470.5 MW)) = \$2.35/kW-mo., to \$17.08/kW-mo. Given the winter 2014-15 monthly reference point for NYC of \$19.54/kW-mo and the NYC UCAP requirement for winter 2014-15 of 9,508.6 MW, a reduction of 218.7 MW in the amount of UCAP supplied during the winter would have caused the price of UCAP to increase by \$19.54/kW-mo. × (218.7 MW / (18% × 9,508.6 MW)) = \$2.50/kW-mo., to \$7.28/kW-mo.

[62] In the scenario with entry, the G-J UCAP price was \$9.72/kW-mo. in the summer and \$3.61/kW-mo. in the winter. Given the summer 2014 monthly reference point for G-J of \$12.90/kW-mo. and the G-J UCAP requirement for summer 2014 of 13,494.9 MW, a reduction of 204.2 MW in the amount of UCAP supplied during the summer would have caused the price of G-J UCAP to increase by \$12.90/kW-mo. × (204.2 MW / (15% × 13,494.9 MW)) = \$1.31/kW-mo., to \$11.02/kW-mo. Given the winter 2014-15 monthly reference point for G-J of \$12.81/kW-mo and the UCAP requirement for winter 2014-15 of 13,582.3 MW, a reduction of 218.7 MW in the amount of UCAP supplied during the winter would have caused the price of G-J UCAP to increase by \$12.81/kW-mo. × (218.7 MW / (15% × 13,582.3 MW)) = \$1.39/kW-mo., to \$4.99/kW-mo.

= 21.1 MW in the winter. Therefore, the total amount the LSE pays for G-J UCAP purchased in the SMA is 42.3 MW × \$11.02/kW-mo. = \$467,000 in each summer month, and 21.1 MW × \$4.99/kW-mo. = \$105,000 in each winter month.

98. Also, the LSE will now have a net short position in the ROS market. In the scenario in which the new generator entered, I assumed that the LSE had just enough ROS UCAP to offset the difference between its NYCA and G-J UCAP purchase obligations. However, while its share of the G-J UCAP purchase obligation is 22.2 MW lower during the summer and 23.7 MW lower during the winter than in the scenario in which the new generator enters, its share of the overall NYCA purchase obligation remains the same. That means that it must purchase 22.2 MW of ROS UCAP in the summer and 23.7 MW of ROS UCAP in the winter. Since the price of ROS UCAP averaged \$5.96/kW-mo. in the summer 2014 capability period and \$2.03/kW-mo. in the winter 2014-15 capability period, its cost of purchasing ROS UCAP is 22.2 MW × \$5.96/kW-mo. = \$132,000 in each summer month, and 23.7 MW × \$2.03/kW-mo. = \$48,000 in each winter month. Added to the costs of purchasing NYC and G-J UCAP in the SMA, this LSE's total annual cost of purchasing UCAP in the SMA is \$41,575,000, which is slightly less than the \$41,595,000 cost this LSE would have incurred if it had sponsored entry of the new generator, as calculated in Table 6.

Step 5: Maximum Net Short Thresholds for LSEs Serving Different Shares of NYC Load (if those LSEs Do Not Serve Load in the LHV)

99. Consequently, it is not in this LSE's interest to sponsor entry of an uneconomic new generator. While doing so would cause the price of NYC UCAP in the SMA to fall from \$17.08/kW-mo. in the summer and \$7.28/kW-mo. in the winter to \$14.73/kW-mo. in the summer and \$4.78/kW-mo. in the winter, and would also cause the

price of G-J UCAP in the SMA to fall from $11.02/kW-mo. in the summer and $4.99/kW-mo. in the winter to $9.72/kW-mo. in the summer and $3.61/kW-mo. in the winter, the cost of subsidizing uneconomic entry more than offsets the impact of these price reductions on the LSE's cost of purchasing ICAP in the SMA.

100. However, if this LSE's net short position had increased slightly, from 5 percent of its UCAP purchase obligation for NYC to 5.5 percent, it would have been in its financial interest to sponsor entry of that generator, as the amount it pays for ICAP would have been lower if it had sponsored entry than if it had not. Therefore, the maximum net short position (rounded down to the nearest half percent) for an LSE that serves 15 percent of load in NYC that does not give it an incentive to sponsor uneconomic entry is 5 percent of its UCAP purchase obligation for NYC.

101. The left side of Table 8 summarizes the largest net short positions (after entry), in increments of 0.5 percent of an LSE's NYC UCAP purchase obligations, that LSEs serving load in NYC but not the LHV can have without having an incentive to sponsor uneconomic entry. As it shows, this net short position is almost constant.[63] An

[63] In contrast, the LHV maximum net short threshold analysis concluded that the maximum net short threshold for entry in the LHV should decrease as the share of load served by an LSE increases. Depending on the specifics of the example, the maximum net short position that would give an LSE an incentive to sponsor uneconomic entry may increase, decrease or stay roughly the same as the LSE's load share increases. This is a consequence of the impact that adding the generator has on an LSE's UCAP purchase obligation. If adding a generator did not affect an LSE's UCAP purchase obligation, then larger LSEs would always benefit more from the impact that uneconomic entry would have on UCAP prices, so it would always be necessary to apply more stringent thresholds as LSEs' load shares increased. But LSEs with larger load shares will also bear a larger share of the increase in UCAP requirements that results from adding a generator, which has an offsetting impact on their ICAP costs.

To illustrate how the maximum net short threshold may be the same for LSEs with different shares of load, suppose that an LSE that serves 10 percent of load in a region is considering whether to sponsor a new generator that can provide 200 MW of UCAP in that region at a net cost of $11.50/kW-mo. If the generator is built, the overall UCAP obligation for that region will be 10,000 MW and the price of UCAP will be $11.50/kW-mo.; if not, the overall UCAP obligation for that region will be 9,800 MW and the price of UCAP will be $9.50/kW-mo. (To simplify the example, I will only consider the cost of meeting the UCAP requirement for this single region.) Also assume that in addition to the new generator, the LSE

LSE with a 30 percent load share in NYC can have a net short position equal to 5 percent of its share of the NYC UCAP purchase obligation (after entry) without having an incentive to sponsor uneconomic entry, because its annual ICAP costs will be $52,716,000 if it sponsors uneconomic entry and $52,660,000 if it does not. Similarly, an LSE with a 5 percent load share in NYC can have a net short position equal to 4.5 percent of its share of the NYC UCAP purchase obligation (after entry) without having an incentive to sponsor uneconomic entry, because its annual ICAP costs will be $33,885,000 if it sponsors uneconomic entry and $33,813,000 if it does not. But if after entry, either LSE's net short position had been increased by 0.5 percent of its NYC UCAP purchase obligation, its ICAP costs would be lower if it had sponsored the uneconomic entry, as the right side of Table 8 shows.

102. Therefore, the maximum net short threshold for a new resource in NYC that is sponsored by an LSE that serves load in NYC, but not in the LHV, is 4.5 percent of that LSE's anticipated NYC UCAP purchase obligation if the LSE serves less than 10

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already holds 685 MW of UCAP in that region. Then, if it sponsors entry, it would hold 885 MW of UCAP, its UCAP purchase obligation would be 10% × 10,000 MW = 1,000 MW, its net short position would be (1000 MW – 885 MW) / 1000 MW = 11.5 percent of its UCAP purchase obligation, and its ICAP procurement cost would be (1,000 MW – 885 MW) × $9.50/kW-mo. + 200 MW × $11.50/kW-mo. = $3,392,500. If it does not sponsor entry, its ICAP procurement cost would be (10% × 9,800 MW – 685 MW) × $11.50/kW-mo. = $3,392,500. Consequently, this LSE's maximum net short threshold would be 11.5 percent, as this is the point where it incurs the same ICAP cost whether it sponsors uneconomic entry or not.

If this LSE were to serve 20 percent of the load and, following entry, its net short position was equal to 11.5 percent of its UCAP purchase obligation, then if it sponsors entry, its UCAP purchase obligation would be 20% × 10,000 MW = 2,000 MW, its net short position would be 11.5% × 2,000 MW = 230 MW (so it would hold 1,770 MW of UCAP), and its ICAP procurement cost would be 230 MW × $9.50/kW-mo. + 200 MW × $11.50/kW-mo. = $4,485,000. Meanwhile if it were not to sponsor entry, it would only hold 1,770 MW – 200 MW = 1,570 MW of UCAP, but its UCAP purchase obligation would fall to 20% × 9,800 MW = 1,960 MW, so its net short position would be 1,960 MW – 1,570 MW = 390 MW of UCAP, and its ICAP procurement cost would be 390 MW × $11.50/kW-mo. = $4,485,000. Therefore, despite the fact that it serves twice as much load as the in the preceding paragraph, this LSE's maximum net short threshold would also be 11.5 percent, as this is the point where it incurs the same ICAP cost whether it sponsors uneconomic entry or not.

percent of NYC load, and 5 percent of that LSE's anticipated NYC UCAP purchase obligation otherwise.

Table 8: Maximum Net Short Thresholds for Entry in NYC (For LSEs That Serve Load in NYC But Not in the LHV)

LSE's Share of NYC Load	Max. Net Short Threshold as % of LSE's NYC UCAP Obligation	ICAP Procurement Costs ($000/yr.)		Slightly Larger Net Short Position	ICAP Procurement Costs ($000/yr.)	
		With Entry	Without Entry		With Entry	Without Entry
5%	4.5%	33,885	33,813	5.0%	34,181	34,184
10%	5.0%	37,888	37,880	5.5%	38,480	38,623
15%	5.0%	41,595	41,575	5.5%	42,483	42,689
20%	5.0%	45,302	45,270	5.5%	46,486	46,756
30%	5.0%	52,716	52,660	5.5%	54,493	54,890

Thresholds for LSEs That Serve Load in the LHV

Step 3: Cost of Covering an LSE's Net Short Position If It Sponsors Uneconomic Entry in NYC (if that LSE Serves Load in the LHV)

103. This set of calculations, which is summarized in Table 9, assumes that an LSE serves load in the LHV, and as a result, it serves both 15 percent of the load in NYC and 15 percent of load in G-J. They also assume that this LSE sponsors entry of the proxy generator in NYC and, after taking the ICAP provided by that generator into account, has a net short position equal to 5.5 percent of its UCAP purchase obligations for both NYC and G-J (in both the summer and the winter).

Table 9: ICAP Costs for an LSE Serving 15 Percent of G-J and NYC Load that Sponsors Entry of the Proxy Generator and Has 5.5 Percent Net Short Positions in Both Localities

	Summer Months				Winter Months				Annual
	NYC	G-J	NYCA	Total	NYC	G-J	NYCA	Total	Total
LSE % of Forecasted Peak Load (MW)	15.00%	15.00%	7.26%		15.00%	15.00%	7.26%		
Total UCAP Obligation (MW)	9,895.1	13,993.4	37,473.0		10,801.1	15,045.0	39,956.6		
LSE UCAP Obligation (MW)	1,484.3	2,099.0	2,720.1		1,620.2	2,256.7	2,900.4		
UCAP Holdings Before SMA (MW)	1,402.6	1,983.6	2,604.6		1,531.1	2,132.6	2,776.2		
Net Short Pos'n Before SMA (MW)	81.6	115.4	115.4		89.1	124.1	124.1		
SMA UCAP Price ($/kW-mo.)	14.73	9.72	5.96		4.78	3.61	2.03		
Cost of SMA Purchases ($000/mo.)	1,203	329	0	1,531	426	127	(0)	553	12,506
Cost of Capacity from Proxy Gen. ($000/yr.)									30,474
Total Cost of Capacity ($000)									42,979

104. Under the market conditions assumed for this analysis, the NYC UCAP price following entry will be $14.73/kW-mo. in the summer and $4.78/kW-mo. in the

winter. Above, I calculated the overall NYC UCAP purchase obligation that corresponds to those prices and the portion of that UCAP purchase obligation that would be allocated to an LSE serving 15 percent of NYC load; it was 1,484.3 MW in summer months and 1,620.2 MW in winter months.[64] Therefore, this LSE's net short position with regard to that UCAP purchase obligation is 5.5% × 1,484.3 MW = 81.6 MW in summer months and 5.5% × 1,620.2 MW = 89.1 MW in winter months, and the total amount it pays for NYC UCAP purchased in the SMA at the post-entry prices is 81.6 MW × $14.73/kW-mo. = $1,203,000 in each summer month, and 89.1 MW × $4.78/kW-mo. = $426,000 in each winter month.

105. Similarly, under the market conditions assumed for this analysis, the G-J UCAP price following entry will be $9.72/kW-mo. in the summer and $3.61/kW-mo. in the winter. Above, I calculated the overall G-J UCAP purchase obligation that corresponds to those prices and the portion of that UCAP purchase obligation that would be allocated to an LSE serving 15 percent of G-J load; it was 2,099.0 MW in summer months and 2,256.7 MW in winter months.[65] Its net short position with regard to that UCAP purchase obligation is 5.5% × 2,099.0 MW = 115.4 MW in summer months and 5.5% × 2,256.7 MW = 124.1 MW in winter months. However, it only pays the G-J price for the amount by which its net short position in G-J exceeds its net short position in NYC, which is 115.4 MW – 81.6 MW = 33.8 MW in the summer and 124.1 MW – 89.1 MW = 35.0 MW in the winter. Therefore, the total amount the LSE pays for G-J UCAP

[64] *See* ¶ 88 *supra*.

[65] *See* ¶ 68 *supra*.

purchased in the SMA is 33.8 MW × \$9.72/kW-mo. = \$329,000 in each summer month, and 35.0 MW × \$3.61/kW-mo. = \$127,000 in each winter month.

106. This LSE will also have an obligation to purchase a certain amount of UCAP to cover the difference between its NYCA and G-J purchase obligations, which can be met using UCAP from the ROS region. Above, I calculated that for an LSE that serves 15 percent of load in G-J, the difference between its share of the UCAP purchase obligation for the NYCA as a whole and its share of the UCAP purchase obligation for G-J was 621.1 MW in the summer and 643.6 MW in the winter.[66] As in the previous two cases, I assume that this LSE already holds sufficient ROS UCAP to meet the difference between its share of the NYCA and G-J UCAP purchase obligations. Therefore, it does not incur any additional cost to purchase ROS UCAP in the SMA.

107. Taking into account the annual cost of sponsoring the entry of new capacity, which was calculated as \$30,474,000 in Table 5, the total cost incurred by this LSE to procure ICAP to cover its net short position is \$42,979,000 per year.

Step 4: Cost of Covering an LSE's Net Short Position If It Does Not Sponsor Uneconomic Entry in NYC (if that LSE Serves Load in the LHV)

108. Table 10 illustrates the costs that this LSE would incur to purchase ICAP in the SMA if it does not sponsor entry of the proxy generator in NYC.

109. Once more, not building the new generator affects the LSE's net short position in two ways. The LSE's overall UCAP holdings fall by the amount of UCAP the proxy generator would have provided. But not building the new generator will reduce the overall NYC and G-J UCAP purchase obligations, relative to the scenario presented

[66] *See* ¶ 69 *supra*.

above which assumed that the generator was built, which will therefore reduce the LSE's share of those UCAP purchase obligations.

110. Above, I calculated the impact that not building the new generator would have had on the overall UCAP purchase obligations for NYC and G-J, under the assumption that those obligations would have fallen by the amount of UCAP that new generator would have provided. I also calculated the impact this would have had on the share of NYC UCAP purchase obligations allocated to an LSE serving 15 percent of NYC load. It would have reduced this LSE's share of the NYC UCAP purchase obligation by 30.6 MW during the summer and 32.8 MW during the winter.[67] Similar calculations demonstrate that this LSE's share of the UCAP purchase obligation for G-J are also 30.6 MW lower in the summer and 32.8 MW lower in the winter than they would have been if the new generator had entered the market.

Table 10: ICAP Costs for the Same LSE as Table 9
If It Does Not Sponsor Entry of the Proxy Generator

	Summer Months				Winter Months				Annual
	NYC	G-J	NYCA	Total	NYC	G-J	NYCA	Total	Total
LSE % of Forecasted Peak Load (MW)	15.00%	15.00%	7.26%		15.00%	15.00%	7.26%		
UCAP from Proxy Generator (MW)	204.2	204.2	204.2		218.7	218.7	218.7		
Total UCAP Obligation (MW)	9,690.9	13,789.2	37,473.0		10,582.4	14,826.2	39,956.6		
LSE UCAP Obligation (MW)	1,453.6	2,068.4	2,720.1		1,587.4	2,223.9	2,900.4		
UCAP Holdings Before SMA (MW)	1,198.4	1,779.3	2,400.4		1,312.3	1,913.9	2,557.5		
Net Short Pos'n Before SMA (MW)	255.2	289.0	319.7		275.0	310.0	342.9		
SMA UCAP Price ($/kW-mo.)	17.08	11.02	5.96		7.28	4.99	2.03		
Cost of SMA Purchases ($000/mo.)	4,360	373	183	4,916	2,002	175	67	2,244	42,956

111. Taking this impact on the LSE's share of UCAP purchase obligations into account, the LSE's net short position with regard to its NYC UCAP purchase obligation, which was 81.6 MW in the summer and 89.1 MW in the winter in the scenario with entry, increases to 81.6 MW + 204.2 MW – 30.6 MW = 255.2 MW in summer months and 89.1 MW + 218.7 MW – 32.8 MW = 275.0 MW in winter months. The reduction in

[67] *See* ¶ 94 *supra*.

the total amount of UCAP sold in NYC also causes the NYC UCAP price to be higher than in the scenario with entry. It rises to \$17.08/kW-mo. in the summer and \$7.28/kW-mo. in the winter.[68] Therefore, the total amount the LSE pays for NYC UCAP purchased in the SMA is 255.2 MW × \$17.08/kW-mo. = \$4,360,000 in each summer month, and 275.0 MW × \$7.28/kW-mo. = \$2,002,000 in each winter month.

112. The LSE's net short position with regard to its G-J UCAP purchase obligation, which was 115.4 MW in the summer and 124.1 MW in the winter in the scenario with entry, also increases, to 115.4 MW + 204.2 MW – 30.6 MW = 289.0 MW in summer months and 124.1 MW + 218.7 MW – 32.8 MW = 310.0 MW in winter months. The reduction in the total amount of UCAP sold in G-J causes the G-J UCAP price to be higher than in the scenario with entry; it rises to \$11.02/kW-mo. in the summer and \$4.99/kW-mo. in the winter.[69] But it only pays the G-J price for the amount by which its net short position in G-J exceeds its net short position in NYC, which is 289.0 MW – 255.2 MW = 33.8 MW in the summer and 310.0 MW – 275.0 MW = 35.0 MW in the winter. Therefore, the total amount the LSE pays for G-J UCAP purchased in the SMA is 33.8 MW × \$11.02/kW-mo. = \$373,000 in each summer month, and 35.0 MW × \$4.99/kW-mo. = \$175,000 in each winter month.

113. Also, the LSE will now have a net short position in the ROS market. In the scenario in which the new generator entered, I assumed that the LSE had just enough ROS UCAP to offset the difference between its NYCA and G-J UCAP purchase obligations. However, while its share of the G-J UCAP purchase obligation is 30.6 MW

[68] *See* note 61 *supra*.

[69] *See* note 62 *supra*.

lower during the summer and 32.8 MW lower during the winter than in the scenario in which the new generator enters, its share of the overall NYCA purchase obligation remains the same. That means that it must purchase 30.6 MW of ROS UCAP in the summer and 32.8 MW of ROS UCAP in the winter. Since the price of ROS UCAP averaged $5.96/kW-mo. in the summer 2014 capability period and $2.03/kW-mo. in the winter 2014-15 capability period, its cost of purchasing ROS UCAP is 30.6 MW × $5.96/kW-mo. = $183,000 in each summer month, and 32.8 MW × $2.03/kW-mo. = $67,000 in each winter month. Added to the costs of purchasing NYC and G-J UCAP in the SMA, this LSE's total annual cost of purchasing UCAP in the SMA is $42,956,000, which is slightly less than the $42,979,000 cost this LSE would have incurred if it had sponsored entry of the new generator, as calculated in Table 9.

Step 5: Maximum Net Short Thresholds for LSEs Serving Different Shares of G-J and NYC Load (if those LSEs Serve Load in the LHV)

114. Consequently, it is not in this LSE's interest to sponsor entry of an uneconomic new generator. While doing so would cause the price of NYC UCAP in the SMA to fall from $17.08/kW-mo. in the summer and $7.28/kW-mo. in the winter to $14.73/kW-mo. in the summer and $4.78/kW-mo. in the winter, and would also cause the price of G-J UCAP in the SMA to fall from $11.02/kW-mo. in the summer and $4.99/kW-mo. in the winter to $9.72/kW-mo. in the summer and $3.61/kW-mo. in the winter, the cost of subsidizing uneconomic entry more than offsets the impact of these price reductions on the LSE's cost of purchasing ICAP in the SMA.

115. However, if this LSE's net short positions had increased slightly, from 5.5 percent of its UCAP purchase obligations for NYC and G-J to 6 percent, it would have been in its financial interest to sponsor entry of that generator, as the amount it pays for

ICAP would have been lower if it had sponsored entry than if it had not. Therefore, the maximum net short position (rounded down to the nearest half percent) for an LSE that serves 15 percent of load in NYC and G-J that does not give it an incentive to sponsor uneconomic entry is 5.5 percent of its UCAP purchase obligations for NYC and G-J.

116. The left side of Table 11 summarizes the largest net short positions (after entry), in increments of 0.5 percent of an LSE's NYC and G-J UCAP purchase obligations, that LSEs serving load in NYC and the LHV can have without having an incentive to sponsor uneconomic entry. As it shows, this net short position is, once more, almost constant. An LSE with a 30 percent load share in both NYC and G-J can have net short positions equal to 5.5 percent of its NYC and G-J UCAP purchase obligations (after entry) without having an incentive to sponsor uneconomic entry, because its annual ICAP costs will be $55,485,000 if it sponsors entry and $55,423,000 if it does not. Similarly, an LSE with a 5 percent load share in both NYC and G-J can have net short positions equal to 5 percent of its NYC and G-J UCAP purchase obligations (after entry) without having an incentive to sponsor uneconomic entry, because its annual ICAP costs will be $34,263,000 if it sponsors uneconomic entry and $34,191,000 if it does not. But if, after entry, either LSE's net short positions had been increased by 0.5 percent of its NYC and G-J UCAP purchase obligations, its ICAP costs would have been lower if it had sponsored the uneconomic entry, as the right side of Table 11 shows.

117. Therefore, the maximum net short thresholds for a new resource in NYC that is sponsored by an LSE that serves load in both NYC and the LHV are: 5 percent of that LSE's anticipated NYC and G-J UCAP purchase obligations if the LSE serves less

than 10 percent of NYC load or less than 10 percent of G-J load, and 5.5 percent of that LSE's anticipated NYC and G-J UCAP purchase obligations otherwise.

Table 11: Maximum Net Short Thresholds for Entry in NYC (For LSEs That Serve Load in NYC and in the LHV)

LSE's Share of NYC and G-J Loads	Max. Net Short Threshold as % of LSE's NYC and G-J UCAP Obligations	ICAP Procurement Costs ($000/yr.)		Slightly Larger Net Short Position	ICAP Procurement Costs ($000/yr.)	
		With Entry	Without Entry		With Entry	Without Entry
5%	5.0%	34,263	34,191	5.5%	34,642	34,645
10%	5.5%	38,811	38,801	6.0%	39,569	39,743
15%	5.5%	42,979	42,956	6.0%	44,116	44,369
20%	5.5%	47,148	47,112	6.0%	48,664	48,996
30%	5.5%	55,485	55,423	6.0%	57,759	58,250

Sensitivity to Changes in Assumptions

118. In approving PJM's SSE, the Commission noted that the thresholds that PJM proposed to use were based on a number of assumptions that may change over time, so it directed PJM "to submit tariff language memorializing its obligation … to review and, if necessary, revise these thresholds on an appropriate, periodic basis…."[70] PJM's analysis supporting its proposed thresholds assessed whether LSEs that would qualify for the SSE would have had an incentive to sponsor uneconomic new generation entry in the May 2013 Base Residual Auction,[71] whereas my analysis focuses less on current market conditions, so changes in current market conditions would have less of an impact on my results. Consequently, there should be less of a need to review these assumptions to account for changes in market conditions (although such a review might be warranted if, for example, the difference between NYC and G-J UCAP prices were eliminated). My analysis is based on certain other assumptions—in particular, the results of the NYISO's triennial ICAP demand curve study—so whenever the ICAP demand curves are reset it

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[70] PJM Order at P 113.

[71] *PJM Interconnection, LLC,* Response of PJM to the Commission's February 5, 2013 Information Request, Docket No. ER13-535-000 (filed Mar. 4, 2013), Aff. of Andrew L. Ott at 2-11 ("Ott Aff.").

would be reasonable to review whether the maximum net short thresholds proposed herein continue to be appropriate.

119. It is important to point out two areas in which my analysis tends to overestimate incentives to sponsor uneconomic entry, and therefore may set the maximum net short threshold conservatively. First, my analysis assumes that when the new generator enters the market in an MCZ, the UCAP obligation in that MCZ increases by the amount of UCAP the new generator provides. In other words, the entry of the new generator does not reduce the amount of ICAP provided by any other resources, so the ICAP supply curve in the MCZs is vertical. That assumption maximizes the impact that entry of a generator may have on prices. In contrast, if the supply curve is not vertical, then the entry of a generator may induce a reduction in sales by other resources, which may partly or wholly offset the impact of the entry on prices.[72,73] In that case, the impact of entry on ICAP prices, and the incentive for an LSE to sponsor uneconomic entry, would be less than I calculated in my analysis.

120. This impact may be very significant. As PJM's Andrew Ott stated in an affidavit describing the analysis performed by PJM to support its proposed SSE, "[I]nteractions of the [demand] curve with the supply curve, and the shape of the supply

[72] In his affidavit, Dr. Paynter describes one case in which entry in NYC appears to have induced exit that mitigated much of the impact of the entry on NYC ICAP prices. Paynter Aff. at 17:12-21.

[73] On the other hand, I assumed that the supply curve for the NYCA as a whole is horizontal, so that the entry of a new generator had no impact on the overall UCAP purchase obligation for the NYCA. I believe this is a reasonable simplification, particularly in light of the conservative assumptions regarding the impact of entry on NYC and G-J ICAP prices. First, the impact of entry on ICAP prices in ROS as a whole is much smaller than the impact of entry on ICAP prices in the MCZs, both because there is much more ICAP in the NYCA-wide market and because the monthly reference point is set at a considerably lower level. Additionally, ICAP provided by resources outside New York can be sold as ROS capacity, which tends to make the NYCA-wide supply curve much flatter than the supply curve in the MCZs, where imported ICAP can only be sold by resources with UCAP deliverability rights.

curve, can have a dramatic effect on any analysis of the clearing-price reduction effects of new entry….”[74] Mr. Ott compared the results of two analyses performed by Dr. Richard Tabors, one of which did not permit supply to respond to reductions in price, and one of which did. He pointed out that while the "analysis that takes into account the … supply offers still shows very significant price reductions, [those reductions] are markedly smaller than the price reductions from [the] analysis that does not consider supply offers at all."[75] The actual supply curves used that Mr. Ott used in his analysis were more elastic than the ones used in Dr. Tabors' analysis, so the impact on ICAP prices of entry of a new generator was smaller yet.[76]

121. It is unlikely that an LSE that was considering sponsoring an uneconomic new generator because entry of this generator would suppress the price it pays for its remaining UCAP purchase obligations would disregard the likelihood that the reduction in price would lead, sooner or later, to some reduction in supply that would partially or completely offset the impact of the entry. However, because the SMA is operated on monthly basis for ICAP to be provided during the forthcoming month, offers made into the SMA generally cannot be used to indicate the degree to which suppliers will respond to low prices by exiting the market, since generators of 80 MW or larger generally must provide at least 180 days' notice of their intent to retire or mothball their facilities.[77] Consequently, my calculations do not take this into account, but that does not mean that suppliers will not respond to actions that are intended to suppress prices, or that LSEs

[74] Ott Aff. at 12:10-12.

[75] *Id.* at 11:38-39.

[76] *Id.* at 12:23-24, 13:16-18.

[77] New York Public Service Commission Case 05-E-0089, Order Adopting Notice Requirements for Generation Unit Retirements (2005).

would not take suppliers' reactions into account. Instead, it simply means that the maximum net short thresholds calculated here are set quite conservatively.

122. Second, my analysis also assumed that the cost of supporting entry of the proxy generator was equal to the ICAP payment that it would expect to earn from selling its ICAP into the NYISO's ICAP market, assuming that market conditions were equal to the average conditions assumed when the NYISO set its ICAP demand curves. But the entry was assumed to occur when the ICAP surplus exceeded than the average ICAP surplus level that the NYISO assumed when it developed the ICAP demand curves. The presence of this additional capacity will decrease the net revenue (i.e., revenue net of variable costs) that the proxy generator would expect to realize from the sale of energy and ancillary services ("E&AS net revenue"). Consequently, the payment that would be needed to support entry of such a generator would need to increase to offset the difference between the E&AS net revenue that generator would expect to realize at the average market conditions assumed when developing the ICAP demand curves, when entry is economic, and the E&AS net revenue that generator would expect to realize at the conditions assumed in this analysis, when entry is uneconomic. Since my analysis did not consider this factor, it underestimates the cost that would be required to support the entry of the proxy resource when it is uneconomic, and may therefore conclude that it would be in an LSE's financial interest to support uneconomic entry when in fact it would not be in that LSE's interest to do so. This also causes the maximum net short thresholds that I calculated above to be conservative.

CALCULATION OF MAXIMUM NET LONG THRESHOLDS

123. PJM's maximum net long threshold is set at 70 MW for customers whose estimated capacity obligations are less than 500 MW, and the lesser of 15 percent of an LSE's estimated capacity obligation or 750 MW for customers whose estimated capacity obligations are 500 MW or greater.[78] Mr. Ott explained that those thresholds were "reasonable because they serve to limit a self-supply entity from substantially overbuilding while recognizing that the addition of a large resource that may be efficiently sized to accommodate the LSE's long-term needs may put the LSE in a net long position at the beginning of the resource's life."[79] Precisely the same concerns apply in New York. As was the case in PJM, the intent of the maximum net long thresholds proposed in the NYPSC/NYPA Complaint is to permit LSEs to maintain a portfolio of resources that is reasonably consistent with their anticipated future ICAP purchase obligations, while protecting against any efforts to use the SSE to sponsor the entry of uneconomic resources in an attempt to suppress the price paid for ICAP by other LSEs in the state.

124. The MCZs are considerably smaller than most of the regions to which PJM applied its maximum net long thresholds. Supply in the MCZs may also be less elastic than supply in PJM, particularly in the short run, given that unlike New York's SMA, PJM's Base Residual Auction procures ICAP three years in advance. Both of

[78] PJM Order at P 65. PJM also has other provisions for setting the maximum net long threshold that apply to LSEs whose estimated capacity obligations are 15,000 MW or greater. Since no LSEs in New York will have UCAP purchase obligations of more than 15,000 MW in the MCZs, those provisions would not be relevant if they were used in New York.

[79] Ott Aff. at 23:15-18.

these factors would mean that an additional MW of UCAP would have more of an impact on the price of UCAP in an MCZ than it would have in PJM.

125. In recognition of this difference, the NYPSC/NYPA Complaint proposes maximum net long thresholds that are somewhat lower than the corresponding thresholds used in PJM. While the maximum net long threshold would continue to be 15 percent of an LSE's anticipated UCAP obligation in an MCZ, just as in PJM, the cap on the maximum net long threshold, which would apply to the largest LSEs, has been reduced from the 750 MW in effect in PJM to 250 MW for entry in G-J and 200 MW for entry in NYC. The floor for the maximum net long threshold, which would apply to the smallest LSEs, has also been reduced from the 75 MW in effect in PJM to 40 MW. Table 12 compares the maximum net long thresholds that would have been calculated for the MCZs if this proposal had been in effect during the 2014-15 capability year, and compares them to the maximum net long thresholds that PJM would have calculated for its May 2013 Base Residual Auction, if PJM's procedures for setting maximum net long thresholds had been in effect then. As it demonstrates, the maximum net long thresholds proposed in the NYPSC/NYPA Complaint, stated in terms of the number of MW in excess of an LSE's UCAP obligation that an LSE may hold, after accounting for entry of the new resource, are generally much lower than the maximum net long thresholds that PJM's proposal would have applied to LSEs with the same load share in a given region.

Table 12: Comparing Maximum Net Long Thresholds in PJM and New York

LSE's Load Share	Proposed NY Thresholds		PJM Thresholds			
	G-J (MW)	NYC (MW)	RTO (MW)	MAAC (MW)	EMAAC (MW)	SWMAAC (MW)
2%	40	40	488	215	118	70
5%	109	77	750	537	295	129
10%	217	155	1,000	750	591	259
15%	250	200	1,000	750	750	388
20%	250	200	1,300	750	750	517
30%	250	200	1,300	1,000	750	750

126. Meanwhile, the maximum net long thresholds proposed for the NYISO, in conjunction with the proposed maximum net short thresholds calculated previously, fulfill the other requirement for these thresholds, which was to permit LSEs to maintain a portfolio of resources that is reasonably consistent with their anticipated future ICAP purchase obligations. For all of the ICAP provided by a new resource to be exempt from offer floor mitigation under the SSE, the LSE sponsoring that resource must ensure that, after entry of the resource, its net position relative to its anticipated share of the UCAP purchase obligation within an MCZ fits within a “window” defined by the maximum net short and maximum net long thresholds. As the illustrative examples to follow will show, these windows provide entrants with a reasonable amount of leeway to develop portfolios that do not precisely track their UCAP obligations, while not providing excessive room that might permit uneconomic entry that could suppress prices significantly below competitive levels.

127. These thresholds are functions of an LSE’s UCAP purchase obligations, so the level of each of these thresholds for a given LSE will depend on the market conditions at a given point in time. Table 13 shows this window for LSEs with varying shares of load in G-J that are sponsoring a new generator in the LHV. It assumes the same market conditions that were assumed for the maximum net short threshold analyses.

As it shows, if an LSE that serves 15 percent of the load in G-J were to sponsor entry in the LHV, its maximum net short threshold would be 152 MW,[80] and its maximum net long threshold would be set at the 250 MW cap.[81] Consequently, if that LSE is an average of 300 MW short of its anticipated G-J UCAP purchase obligation, in order for the generator it is sponsoring is to qualify for an exemption from offer floor mitigation under the SSE, the amount of UCAP the new generator is expected to provide must be no less than 300 MW – 152 MW = 148 MW, and if the new generator is expected to provide more than 300 MW + 250 MW = 550 MW of UCAP, only the first 550 MW would qualify for an exemption from offer floor mitigation under the SSE.[82]

Table 13: Window for Entry in the LHV that Would Be Eligible for the Proposed SSE

LSE's Share of G-J Load	LSE's G-J UCAP Obligation (MW)	Max. Net Short Threshold (MW)	Max. Net Long Threshold (MW)
5%	726	91	109
10%	1,452	116	218
15%	2,178	152	250
20%	2,904	174	250
30%	4,356	240	250

128. Similarly, Table 14 shows this window for LSEs with varying shares of load in NYC—but no load in the LHV—that are sponsoring a new resource in NYC. It also assumes the same market conditions that were assumed for the maximum net short

[80] At the market conditions that were assumed for the maximum net short threshold analyses, the overall G-J UCAP purchase obligation was 13,993.4 MW in the summer and 15,045.0 MW in the winter (*see* note 46 *supra*), leading to an annual average G-J UCAP purchase obligation of 14,519.2 MW, so this LSE's share of the annual average is 15% × 14,591.2 MW = 2,178 MW. In Table 4, the maximum net short threshold for this LSE was calculated as 7 percent of its anticipated UCAP purchase obligation for G-J. Therefore, its maximum net short threshold is 7% × 2,178 MW = 152 MW.

[81] Fifteen percent of the annual average G-J UCAP purchase obligation of 2,178 MW exceeds the 250 MW cap on the maximum net long threshold, so the cap applies.

[82] That ICAP might still be eligible for an exemption from offer floor mitigation for another reason. Dr. Paynter's affidavit describes other exemptions that might apply to ICAP that does not qualify for an exemption under the SSE.

threshold analyses. As it shows, if an LSE that serves 10 percent of the load in NYC were to sponsor a new generator there, its maximum net short threshold would be 52 MW,[83] and its maximum net long threshold would be 155 MW.[84] Consequently, if that LSE is an average of 200 MW short of its anticipated NYC UCAP purchase obligation, in order for the new generator it is sponsoring to qualify for an exemption from offer floor mitigation under the SSE, the amount of UCAP the new generator is expected to provide must be no less than 200 MW – 52 MW = 148 MW, and if the new generator is expected to provide more than 200 MW + 155 MW = 355 MW of UCAP, only the first 355 MW would qualify for an exemption from offer floor mitigation under the SSE.

Table 14: Window for Entry in NYC that Would Be Eligible for the Proposed SSE (For LSEs That Serve Load in NYC But Not in the LHV)

LSE's Share of NYC Load	LSE's NYC UCAP Obligation (MW)	Max. Net Short Threshold (MW)	Max. Net Long Threshold (MW)
5%	517	23	78
10%	1,035	52	155
15%	1,552	78	200
20%	2,070	103	200
30%	3,104	155	200

129. Finally, Table 15 shows this window for LSEs with varying shares of load in NYC and the LHV that are sponsoring a new resource in NYC. Once more, it assumes the same market conditions that were assumed for the maximum net short threshold analyses. In order for all of the ICAP provided by this new resource to be exempt from

[83] At the market conditions that were assumed for the maximum net short threshold analyses, the overall NYC UCAP purchase obligation was 9,895.1 MW in the summer and 10,801.1 MW in the winter (see n. 57 *supra*), leading to an annual average NYC UCAP purchase obligation of 10,348.1 MW, so this LSE's share of the annual average is 10% × 10,348.1 MW = 1,035 MW. In Table 8, the maximum net short threshold for this LSE was calculated as 5 percent of its anticipated UCAP purchase obligation for G-J. Therefore, its maximum net short threshold is 5% × 1,035 MW = 52 MW.

[84] Fifteen percent of the annual average NYC UCAP purchase obligation of 10,348.1 MW is 155 MW, which is less than the 200 MW cap that applies to entry in NYC.

offer floor mitigation under the SSE, the net position for the LSE sponsoring that resource must fit into the windows for *both* G-J and NYC. Building on the illustrative examples that preceded Tables 13 and 14, suppose that an LSE that serves 15 percent of the load in G-J and 10 percent of the load in NYC, and which is an average of 300 MW short of its anticipated G-J UCAP purchase obligation and 200 MW short of its anticipated NYC UCAP purchase obligation, were to sponsor a new generator in NYC. The maximum net long thresholds that would apply to this LSE are the same thresholds that were calculated in the two preceding examples--250 MW for G-J and 155 MW for NYC—but the maximum net short thresholds are slightly different. For G-J, this LSE's maximum net short threshold is 120 MW,[85] and for NYC, its maximum net short threshold is 57 MW.[86]

130. If the new generator is to qualify for an exemption from offer floor mitigation under the SSE, the sponsoring LSE's net short position after entry must not exceed the maximum net short thresholds for both G-J and NYC. The new generator must be expected to provide no less than 300 MW – 120 MW = 180 MW for the LSE to meet the maximum net short threshold for G-J, and no less than 200 MW – 57 MW = 143 MW for the LSE to meet the maximum net short threshold for NYC. Since the higher

[85] As in the example preceding Table 13, this LSE's share of the annual average UCAP purchase obligation for G-J is 2,178 MW. However, in Table 11, the maximum net short threshold for this LSE for G-J was calculated as 5.5 percent of its anticipated UCAP purchase obligation for G-J, compared to the 7 percent value in Table 4 that was used to calculate the maximum net short threshold for entry in the LHV. Therefore, this maximum net short threshold is 5.5% × 2,178 MW = 120 MW.

[86] As in the example preceding Table 14, this LSE's share of the annual average UCAP purchase obligation for NYC is 1,035 MW. However, in Table 11, the maximum net short threshold for this LSE for NYC was calculated as 5.5 percent of its anticipated UCAP purchase obligation for NYC, compared to the 5 percent value in Table 8 that was used to calculate the maximum net short threshold for entry in NYC by an LSE serving load in NYC only. Therefore, this maximum net short threshold is 5.5% × 1,035 MW = 57 MW.

value controls, this new generator must be expected to provide at least 180 MW of UCAP for the sponsoring LSE to be eligible for an offer floor exemption under the SSE.

131. Similarly, this generator would exceed the maximum net long threshold for G-J if it is expected to provide more than 300 MW + 250 MW = 550 MW of UCAP, and it would exceed the maximum net long threshold for NYC if it is expected to provide more than 200 MW + 155 MW = 355 MW. In this case, the lower value controls, so if the new generator is expected to provide more than 355 MW of UCAP, only the first 355 MW would qualify for an exemption from offer floor mitigation under the SSE.

Table 15: Window for Entry in NYC that Would Be Eligible for the Proposed SSE (For LSEs That Serve Load in NYC and in the LHV)

	G-J			NYC		
LSE's Share of NYC or G-J Load	LSE's UCAP Obligation (MW)	Max. Net Short Threshold (MW)	Max. Net Long Threshold (MW)	LSE's UCAP Obligation (MW)	Max. Net Short Threshold (MW)	Max. Net Long Threshold (MW)
5%	726	36	109	517	26	78
10%	1,452	80	218	1,035	57	155
15%	2,178	120	250	1,552	85	200
20%	2,904	160	250	2,070	114	200
30%	4,356	240	250	3,104	171	200

CONCLUSION

132. Mitigation is more likely to cause harm when it is applied to entities that have no incentive to act in an anticompetitive manner, and when it is difficult to ascertain what offers an entity would have submitted if it had acted in an anticompetitive manner.

133. Both of these concerns apply to the current offer floor mitigation procedures. They mitigate without regard to whether a developer has an incentive to suppress prices below competitive levels; as a result, they may mitigate in cases where there is no reason to suspect that entry reflects anticompetitive intent. Moreover, because it is difficult to determine the minimum ICAP price at which a competitive entrant would

be willing to proceed with entry, they may require a mitigated entrant to submit offers that are not consistent with how it would act in a competitive market. Consequently, mitigation can make things worse, and may deter entry by resources that are economically justified.

134. A well-designed SSE can permit LSEs to hedge their positions through self-supply while addressing some of these concerns. Entities that self-supply the ICAP needed to meet their ICAP purchase obligations should not have an incentive to suppress prices, as they will not have a significant net short position. The SSE would permit such entities to be exempted from unnecessary mitigation, thereby reducing the harm that such mitigation may cause, while also containing safeguards that would prevent LSEs from suppressing those prices significantly below competitive levels.

135. Under the SSE described herein, a new resource in an MCZ that is sponsored by an LSE would only be eligible for exemption from offer floor mitigation under the SSE to the extent that, after the entry of that new resource, that LSE's net short position—*i.e.,* the amount of UCAP it is expected to have to purchase in MCZs—is less than a maximum net short threshold. These thresholds vary depending on the amount of load served by that LSE. The maximum net short thresholds proposed in this affidavit have been developed with the intent of ensuring that LSEs with a financial interest in sponsoring uneconomic entry would not be eligible for exemptions from offer floor mitigation under the SSE. They have been calculated in a conservative manner, especially with respect to the assumptions made regarding the impact that entry would have on the price of ICAP. As a result, it is highly unlikely that LSEs qualifying for

exemptions under the SSE would have a financial incentive to suppress ICAP prices below competitive levels.

136. Also, in order for a new resource in an MCZ that is sponsored by an LSE to be eligible for exemption from offer floor mitigation under the SSE, that LSE's net long position—*i.e.*, the amount of UCAP it is expected to hold, after entry of the new generator, in excess of its share of the UCAP purchase obligation for that MCZ—must be less than a maximum net long threshold. These thresholds will also vary depending on the amount of load served by that LSE. The maximum net long thresholds proposed in this affidavit have been developed with the intent of balancing concerns that they could be used as a vehicle to suppress prices below competitive levels against the need to recognize that, for a number of reasons, it is not practical to expect LSEs to develop self-supply portfolios that precisely track their UCAP purchase obligations at all points in time. The resulting maximum net short thresholds accomplish both of these objectives, as they provide LSEs with a reasonable degree of flexibility while also significantly limiting any potential that the SSE could be used as a vehicle to drive down prices in an anticompetitive manner.

137. This concludes my affidavit.

Appendix A
Data from NYISO Website

Data from NYISO ICAP Demand Curve Models		G-J	NYC
Zero-Crossing Point (% of ICAP Requirement)		115.0%	118.0%
EFORd for Proxy Generator		2.17%	2.17%
Summer DMNC for Proxy Generator (MW)		209.4	208.8
Winter DMNC for Proxy Generator (MW)		225.2	223.6
Ratio of Winter to Summer DMNCs		1.0682	1.0872
Average ICAP Supply in Summer (% of ICAP Reqt.)		101.4%	102.0%
Monthly Reference Point ($/kW-mo. of ICAP)		$ 12.14	$ 18.55

Data from Summer 2014 UCAP/ICAP Demand Curve Translation	NYCA	G-J	NYC
Monthly Reference Point ($/kW-mo. of UCAP)		$ 12.90	$ 19.62
UCAP Requirement (MW)	35,812.4	13,494.9	9,470.5

Data from Winter 2014-15 UCAP/ICAP Demand Curve Translation	NYCA	G-J	NYC
Monthly Reference Point ($/kW-mo. of UCAP)		$ 12.81	$ 19.54
UCAP Requirement (MW)	36,506.6	13,582.3	9,508.6

Peak Load Forecast (MW)	NYCA	G-J	NYC
2014-15 Capability Year	33,665.7	16,291.4	11,782.8

Price of UCAP in Spot Market Auctions ($/kW-mo.)	ROS	LHV	NYC
May 2014	$ 6.68	$ 12.38	$ 18.83
June 2014	$ 6.21	$ 12.35	$ 18.84
July 2014	$ 6.10	$ 12.32	$ 18.69
August 2014	$ 5.80	$ 12.25	$ 18.56
September 2014	$ 5.60	$ 12.04	$ 18.17
October 2014	$ 5.39	$ 11.64	$ 17.94
Summer Average	*$ 5.96*	*$ 12.16*	*$ 18.51*
November 2014	$ 1.43	$ 5.76	$ 8.96
December 2014	$ 3.50	$ 4.76	$ 8.87
January 2015	$ 2.41	$ 3.76	$ 8.80
February 2015	$ 3.36	$ 4.21	$ 8.94
March 2015	$ 0.72	$ 2.93	$ 7.28
April 2015	$ 0.75	$ 2.82	$ 7.30
Winter Average	*$ 2.03*	*$ 4.04*	*$ 8.36*

Data Sources:

Data from NYISO ICAP demand curve models and UCAP/ICAP demand curve translations available at:
http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp
(ICAP Auctions and Reference Documents folders.)

Peak load forecasts, surplus UCAP purchases and UCAP prices available at:
http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do

Overall UCAP obligations calculated based on surplus UCAP purchases and UCAP requirements.

Surplus UCAP Purchases (MW)	NYCA	G-J	NYC
May 2014	1,345.3	81.8	111.9
June 2014	1,549.9	86.0	67.8
July 2014	1,598.6	90.5	81.2
August 2014	1,734.3	101.3	92.5
September 2014	1,819.9	135.3	125.9
October 2014	1,915.8	197.1	146.3
Summer Average	*1,660.6*	*115.3*	*104.3*
November 2014	3,725.5	1,121.1	926.9
December 2014	2,773.5	1,281.0	934.4
January 2015	3,275.5	1,438.9	940.7
February 2015	2,837.4	1,367.7	928.3
March 2015	4,051.9	1,571.5	1,074.0
April 2015	4,036.2	1,588.1	1,072.1
Winter Average	*3,450.0*	*1,394.7*	*979.4*

Overall UCAP Purchase Obligations (MW)	NYCA	G-J	NYC
May 2014	37,157.7	13,576.7	9,582.4
June 2014	37,362.3	13,580.9	9,538.3
July 2014	37,411.0	13,585.4	9,551.7
August 2014	37,546.7	13,596.2	9,563.0
September 2014	37,632.3	13,630.2	9,596.4
October 2014	37,728.2	13,692.0	9,616.8
Summer Average	*37,473.0*	*13,610.2*	*9,574.8*
November 2014	40,232.1	14,703.4	10,435.5
December 2014	39,280.1	14,863.3	10,443.0
January 2015	39,782.1	15,021.2	10,449.3
February 2015	39,344.0	14,950.0	10,436.9
March 2015	40,558.5	15,153.8	10,582.6
April 2015	40,542.8	15,170.4	10,580.7
Winter Average	*39,956.6*	*14,977.0*	*10,488.0*

COMMONWEALTH OF MASSACHUSETTS)
) ss
COUNTY OF MIDDLESEX)

I, MICHAEL D. CADWALADER, being first duly sworn on oath depose and say as follows:

I make this affidavit for the purpose of adopting as my sworn testimony in this proceeding the attached material entitled, "Affidavit of Michael D. Cadwalader."

Further affiant saith not.

Michael D. Cadwalader

On this 20th day of April, 2015, before me, the undersigned notary public, personally appeared Michael D. Cadwalader and acknowledged to me that he/she signed the forgoing document voluntarily for its stated purposes. I identified Michael D. Cadwalader to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

✓ identification based on my personal knowledge of his/her identity, or

✓ current government-issued identification bearing his/her photographic image and signature.

Notary Public
My commission expires:
(SEAL)

OLGA PONOMAREVA
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
August 17, 2018

Exhibit C

Affidavit of Adam Evans

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NEW YORK PUBLIC SERVICE COMMISSION AND NEW YORK POWER AUTHORITY,	)	
COMPLAINANTS,	)	
V.	)	**DOCKET NO. EL15-___-000**
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.,	)	
RESPONDENT.	)	

AFFIDAVIT OF ADAM EVANS
ON BEHALF OF THE COMPLAINANTS

I, Adam Evans, being duly sworn, depose and say:

1. My name is Adam Evans and I am employed by the New York State Department of Public Service ("NYPSC") as a Utility Analyst 2 in the Office of Markets and Innovation. My business address is Three Empire State Plaza, Albany, New York, 12223-1350. My duties with the NYPSC include analyzing and reporting on the New York Independent System Operator ("NYISO") Installed Capacity ("ICAP") market design and operations, evaluating the potential market price impacts of proposed changes in the ICAP markets, and representing the NYPSC in the NYISO's stakeholder processes, including the triennial establishment of the ICAP demand curves.

2. I hold a Bachelor of Business Administration Degree in Finance from James Madison University. Prior to joining the NYPSC in 2010, I held a professional position in Finance as an equities and commodities trader with C + C Trading in New York City.

Purpose and Summary of Affidavit

3. The purpose of my affidavit is to support the NYPSC and New York Power Authority's ("NYPA") (collectively, the "Complainants") Section 206 complaint under the Federal Power Act regarding the need to change the NYISO Market Administration and Control Area Services Tariff ("MST") in a manner that results in buyer-side mitigation ("BSM") rules that are just and reasonable and not unduly discriminatory or preferential.

4. In my affidavit, I (1) explain how the NYISO's BSM rules work; (2) identify the faulty subjective assumptions built into the rules that lead to unreasonable results; (3) describe specific examples of how those rules have been applied in an unjust and unreasonable manner; and (4) demonstrate that because the rules are so subjective in nature, even with better assumption modeling the rules can lead to over-mitigation and therefore must only apply to a narrow subset of projects.

Current BSM Rules

5. The current BSM rules apply to every new generation project or transmission facility coupled with an unforced deliverability right developed in a previously determined mitigated zone, including any existing facility returning from a repowering. The BSM rules apply regardless of whether the developer has legitimate

reasons to construct the facility other than to inappropriately depress capacity market prices.

6. In general, the BSM rules require the NYISO to determine whether a new resource is "economic." If the new resource does not qualify according to the NYISO's tests, the resource is prohibited from bidding below a bid floor which means the resource may not receive capacity revenues.

7. The BSM test has two parts. Market Participants typically refer to these as the Part A test and the Part B test. They are described in the NYISO's Services Tariff in Section 23, Attachment H.

8. The Part A test compares the "Default Net CONE" to a NYISO forecasted clearing price in the assumed first year of the new unit's operation. "CONE" is an acronym for "Cost of New Entry." "Net CONE" is shorthand for the cost of new entry after allowing for a unit's expected market revenues. The test uses an administratively-determined price based on the Net CONE of a fictional proxy unit to determine whether the unit being developed will be "economic." This price is the Default Net CONE. The NYISO tariff fixes the Default Net CONE at 75% of Net CONE of the proxy unit used to establish the demand curve. The Demand Curves are set every three years and are based on the net-cost-of-new-entry of a hypothetical new "proxy" unit in the New York Control Area (NYCA) and in each of the 3 ICAP localities. A facility will pass the Part A test if the Default Net CONE is lower than the projected capacity prices with the inclusion of the prospective new unit. The intent of the design of the Part A test is to offer an exemption if it is forecasted that supply will be tight in the unit's first year of operation.

9. The Part B test compares the NYISO forecasted capacity prices with the inclusion of the prospective new unit for the first three years of the facility's operation from an assumed start date to the unit-specific assumed Net CONE. The unit-specific Net CONE differs from the Default Net CONE as it uses an estimate of the actual unit's costs less the revenues the NYISO projects. If the Unit Net CONE is lower than the average of the three-year forecasted prices, it is exempt from mitigation.

10. The intent of both tests is to exempt a unit deemed to be "economic" as compared to the NYISO forecast. If a Unit passes either Part A or Part B it is exempt from mitigation and is eligible to bid in the capacity market on the same basis as existing capacity resources.

The Flaws With the BSM Rules

11. The two BSM tests are regulatory "tripwires" that are based on assumptions and projections about a resource's future performance and future economic conditions. This design results in a test that ultimately second-guesses developers' evaluations of those factors and their attitudes toward risk. Further, many of the assumptions and projections used by the NYISO to determine whether a unit is "economic" are the result of compromises reached in the stakeholder process. That process does not replicate the analysis that an investor or developer makes when deciding whether to enter a specific market.

12. There is also a fundamental problem with the BSM test in that a developer may have a very different view of the world than the NYISO resulting in vastly different assumptions. The BSM test is based on a snapshot of time- either 1 year or 3 years.

Investment decisions, however, are likely based on a much longer time frame. The developer may have a very different outlook of gas prices, expected existing facility retirements, or environmental rules that form the basis of the assumptions, or not accounted for at all, in the BSM test. This fact alone requires any mitigation be limited to instances where there is an intent to use buyer-side market power to intentionally suppress prices.

13. Leaving aside the obvious concern that a new entrant may have its own view of the market that differs from, and may ultimately prove to be superior to, the NYISO's, there are many aspects of the assumptions used in the current BSM test that lead to unreasonable results and over-mitigation. The NYISO independent market monitoring unit ("MMU"), Potomac Economics, has raised some of these very issues in its reports on the mitigation determinations for the Class Year 2011 and 2012 projects, and I will elaborate on a few main concerns and demonstrate how they lead to erroneous outcomes and make it nearly impossible to "pass" the two tests.

14. The first major issue with the BSM test relates to the assumed entry (in-service) date of the facility being tested. The NYISO assumes the resource being tested will enter service three years after the unit enters a Class Year. The NYISO groups projects in a Class Year to determine how they will share the costs of certain system upgrades. Practical experience shows that this is a faulty assumption because the Class Year study process alone can take over two years. For example, the Class Year 2012 projects did not even receive their final Project Cost Allocations until the end of 2014, yet the BSM test required NYISO to assume that they would be in service less than one year later, in the summer of 2015. To my knowledge, none of the Class Year 2012 projects

have actually begun construction. As the MMU notes in its assessment of the Buyer-side Mitigation Tests for these Class Year 2012 projects, "The BSM measures are intended to provide a developer with the exemption test results *before* it begins building a new facility, since a competitive supplier might not move forward with such a large investment if it was not reasonably certain to receive capacity market revenues."[1] For this reason, a much more reasonable assumption for a unit's entry date might be 3 years from the *conclusion* of the Class Year Process, not from the beginning.

15. The assumed entry date is critical, because of the BSM test's reliance on the demand curves. The slopes for both the NYC and G-J Demand curves are steep, so any erroneous assumptions can make a huge difference in the results of the test. As the MMU report acknowledges, pushing back the assumed entry date by even one year for the CY2012 Berrians project could have increased the forecasted clearing price for Zone J by $23/kW year in UCAP terms. To put that in perspective, the Berrians project failed the Part A test by around $34/kW-year, so assuming an expected entry date of 2017 could have by itself potentially exempted Berrians. This increase is attributable to load growth (165MW) and the current Demand Curve escalation rate (2.2%). For a project with a longer lead time, it could be easy to imagine how the assumed date of entry could result in a forecast of clearing prices over $75/kW year less than what they would be if a more realistic entry date for the project were used.

16. The second major erroneous assumption relates to the inclusion of all Mothballed facilities as in-service units in the price forecast. To use Class Year 2012 as

[1] Potomac Economics, Ltd., *Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2012 Projects* at 43-44 (Jan. 13, 2015) ("Class Year 2012 Report"), *available at* http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Class%20Year%202012/MMU%20Report%20on%20CY%202012%20BSM%20Tests.pdf.

an example, 421.4 MW of Mothballed capacity was included in the forecast even though the MMU points out the majority of this capacity "will not likely return to service"(page 13). To give an indication of the unreasonableness of this assumption, the NYISO states the Zone J price forecast for the Part A test is $88.83/kW-year for 2015. In 2014, however, the annual spot price for Zone J was over $167/kW-year, nearly twice the NYISO forecast used in the mitigation analysis for the Berrians project. So the working assumption is that 421.4 MW of Mothballed capacity that did not return to the market when prices were high at $167/kW-year, will for some reason return to the market at half those prices.

17. The concern even goes further than the straight economics of the individual plant when the Mothballed facility is owned by a generation owner who owns a large fleet. Potomac Economics raised this concern in both its analysis of Class year 2011 and 2012 Mitigation determinations. In the 2011 Report, the MMU stated that "Suppliers with large generation portfolios that include mothballed units may not have competitive incentives to re-enter the market, since this would lower the capacity prices for other units in the portfolio. There are currently no mitigation measures that would compel a supplier to return a mothballed unit to service if it were economic to do so." (Page 9 CY2011 CPV Valley report). Excluding all of the mothballed facilities' capacity from the forecast would have increased the forecasted clearing prices for Zone J by over $56/kW-year UCAP for the CY2012 Berrians project, which failed the Part A test by about $34/kW-year.

18. A third erroneous assumption in the BSM test is related to the inclusion as in-service units prior Class Year projects that received an exemption. Under current

rules, all previous Class year projects that received an exemption are included in the price forecast, regardless of whether the project has actually begun moving forward. The current slope for the G-J Demand Curve is approximately 0.63 per 100 MW. So under the current rules, if a 500MW facility were exempted in the New Capacity Zone, yet never made any effort to complete development, forecasted prices could be nearly $40/kW-year lower than they should be (500 MW yields $0.63/kW-month x 12 months/year x 5 = $37.80/kW-year.). When combined with the assumed entry date and mothballed capacity assumption, the result of these assumptions is to make it virtually impossible for any new entrant to qualify for an exemption.

19. There is another timing problem that is inherent in the BSM test that will typically lead to under-forecasting future prices and making it harder for a unit to receive an exemption. A bias towards under-forecasting tends to suggest that there is plenty of supply in the market and will make a new entrant appear “uneconomic” when supply is actually tighter than the forecast indicates. Units above 80 MW are only required to notice the PSC of their intent to retire 6 months in advance of leaving the market. On the other hand it takes 3 years or more for new units to enter the market. Consider the fact that previously exempted resources—whether or not they have advanced to commercial operation—and previously mitigated Examined facilities that have passed certain milestones are both included in the forecast, yet only units who are intending to retire in the next 6 months are excluded, and there will always be a bias towards under-forecasting capacity prices.

Examples of Unjust Application of BSM Rules

20. The MMU itself has identified two units that failed the BSM test based primarily on the erroneous assumptions in the model. In its review of both the Class Year 2011 and 2012 Berrians projects, the MMU report cited concerns with the results. In the CY 2011 report on Berrians the MMU stated "Overall, we estimate that if the three factors (including entry start date and treatment of mothballed units) above were addressed, the price forecast could increase to more than $140/kW-year UCAP in the Part A test, so addressing the three issues might have caused the Berrians project to pass the Part A test." (pg 14)

21. In the recent MMU report on the CY2012 Berrian's III project, the MMU raised many of the same concerns. The report states "Overall, we find that if these issues (entry date, mothballed capacity) could have been addressed, it likely would have altered the price forecast and, thus, could have affected whether the CY12 Berrians Project received an exemption in the Final Decision Round" (pg 14).

22. These two units are actual real-life examples of the BSM test being inaccurate and mitigating prospective units. The question of how many units never even begin the process because of the uncertainty surrounding potential revenues is even more concerning. The current BSM measures as they stand today, threaten the reliability of our system in the future.

Recommendations

23. Simply including better assumptions as part of the mitigation tests is not likely to resolve the issues inherent in the faulty BSM rules that the NYISO applies. As mentioned above, even with better assumption modeling, a developer's motivation and

analysis on whether to develop a project is likely to be very different from the elements that the NYISO includes in determining whether a project should be mitigated. The real threat of over-mitigation exists whether or not NYISO is more disciplined and accurate with its base assumptions because so many of the assumptions are subjective in nature under all circumstances.

24. In his affidavit, Dr. Paynter describes the inefficient outcomes in applying the BSM rules to too broad a universe of new entry into market, so I will not duplicate that effort here. However, it is imperative for an efficient market outcome that the tests apply only to a limited set of resources that have the incentive and ability to suppress market prices. While the current market rules have led to real instances of over-mitigation, as outlined above, the instances where a project is not even put forward for consideration because it is unlikely to pass either the Part A or Part B tests is just as deleterious to market outcomes and may even be more problematic from the standpoint of benefits to consumers. Therefore, the mitigation rules should only apply to a small subset of resources as described by Dr. Paynter.

25. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth herein are true to the best of my knowledge, information, and belief.

Adam B. Evans

May 7, 2015

Subscribed and sworn to before me
this 7th day of May, 2015

Notary Public

My Commission expires:
1/31/18

LEONARD J. VAN RYN
Notary Public, State of New York
Qualified in Albany County
My commission expires 1/31/18
02VA4780265

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NEW YORK PUBLIC SERVICE COMMISSION, NEW YORK POWER AUTHORITY, AND NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY	)	
COMPLAINANTS,	)	
V.	)	**DOCKET NO. EL15-___-000**
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.	)	
RESPONDENT.	)	

NOTICE OF COMPLAINT

( )

Take notice that on May 8, 2015, the New York Public Service Commission, New York Power Authority, and New York State Energy Research and Development Authority (collectively the "Complainants") pursuant to sections 206 and 306 of the Federal Power Act[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission")[2] filed a complaint ("Complaint") against the against the New York Independent System Operator, Inc. ("NYISO").

The Complainants certify that a copy of the Complaint has been served on NYISO. Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure.[3] Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions or protests must be filed on or before the

[1] 16 U.S.C. §§ 824e, 825e (2012).

[2] 18 C.F.R. § 385.206 (2014).

[3] *Id*. §§ 385.211 and 385.214.

comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose,
Secretary

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document, by overnight service and email, on the respondent, the New York Independent System Operator, Inc., to the attention of the following individuals:

Dated at Washington, D.C. this 8th day of May, 2015.

/s/ Patrick O. Daugherty

Patrick O. Daugherty
Van Ness Feldman, LLP
1050 Thomas Jefferson St., N.W.
Washington, D.C. 20007

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