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May 4, 2009

By Hand

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

PUBLIC VERSION

Response of the New York Independent System Operator, Inc. to Deficiency Letter Dated April 2, 2009 in Docket Nos. ER01-3001-021, ER03-647-012, ER01-3001-022 and ER03-647-013

Dear Ms. Bose:

The New York Independent System Operator, Inc. ("NYISO") submits the following response to the requests for information set forth in the Deficiency Letter issued in the above dockets dated April 2, 2009 ("April 2 Letter"). As requested in the April 2 letter, six copies of this response are being sent to your office, with a seventh copy to Ms. Katie Williams, Office of Energy Market Regulation, Division of Tariffs and Market Development-East (Room 82-38).

The April 2 Letter requested three categories of additional information, as indicated below, to complete the annual reports on the NYISO's Installed Capacity ("ICAP") Demand Curves for the years 2006, 2007 and 2008 ("Relevant Period").[1] In addition, the April 2 Letter requested a legible version of "Table 1: Breakout of Unoffered and Unsold Capacity Caps MW Caps off by Type of Market Participant." A copy of this table is included as Attachment 1 to this response.

This filing contains confidential trade secret and commercial information relating to the identity of installed capacity offers and awards of certain ICAP suppliers. This information is set forth in Attachment 2 to this response and is described further below. This information is not otherwise disclosed by the NYISO, and disclosure of such information could adversely

[1] April 2 Letter at 2. Unless otherwise specified, capitalized terms have the meanings specified in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff").

affect competition in the markets administered by the NYISO. Accordingly, the NYISO requests privileged treatment for the confidential portions of Attachment 2. 18 C.F.R. §§ 388.107(d); and 388.112. In addition, the NYISO requests that this information be exempt from the public disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, because it is confidential, commercially sensitive information.

This response is marked as required by the Commission. Information for which confidential treatment is being sought has been masked in the public version. The masked information pertains to the identity of the entities making capacity offers, and the total quantities of capacity offered, since that could reveal the identities.

1) *Revised analysis of going-forward costs.*

The April 2 Letter requests a revised analysis of the going-forward costs of the Rest of State ("ROS") generating units whose capacity offers were not accepted during the Relevant Period, with the going-forward costs shown without adjustments for (i) costs associated with the risks of Day-Ahead Market bidding, and (ii) burning Powder River Basin coal.[2]

This revised analysis is provided in Attachment 3 to this response. Attachment 3 is an affidavit prepared by Mr. Christopher D. Ungate, a Senior Consultant for Sargeant & Lundy LLC, who has prepared previous analyses of going-forward costs in the foregoing dockets and in Docket No. EL07-39-000. As Mr. Ungate has stated in prior submissions, going-forward costs for ICAP suppliers generally include the following: (a) labor for routine operations and maintenance, (b) routine materials and contract services, (c) administrative and general costs, and (d) insurance.[3]

Attachment 3 provides an analysis of those components of going forward costs for the Relevant Period, for each class of unit with offered but unsold capacity.[4] The relevant units are identified in Attachment 2, which is a spreadsheet showing the offers from ROS ICAP suppliers for Unforced Capacity ("UCAP") MW offered but not sold, along with the quantities of UCAP sold and not sold.[5] As in Mr. Ungate's prior analysis, the relevant units were divided

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[2] April 2 Letter at 2.

[3] *See* NYISO July 25, 2008 filing in Docket Nos. ER01-3001-019 and ER03-647-011, Affidavit of Christopher D. Ungate ¶ 9.

[4] Attachment 3, Ungate Aff. at Exhibit B.

[5] Attachment 2 was prepared by and under the direction of Ms. Nicole Bouchez, the Manager of Market Monitoring and Performance of the NYISO. Attachment 4, Bouchez Aff. ¶ 4.

into classes based on primary fuel and technology.[6] Exhibit D of Attachment 3 sets forth an analysis of these going-forward costs for each relevant class of unit and for each year of the Relevant Period with and without adjustments for costs associated with the risks of Day-Ahead Market bidding, and for burning Powder River Basin coal. Exhibit D of Attachment 3 also shows the other adjustments to going-forward costs identified in the NYISO's July 25, 2008 filing, updated as necessary for application in 2008.

2) *Uncertainty in estimating energy and ancillary service revenues.*

The April 2 Letter also requests that the revised analysis include a reasonable range of values for the uncertainty in estimating expected energy and ancillary service revenues, including the associated range of capacity prices, and an analysis of which capacity would be accepted in the auction, with this adjustment to the estimated going forward costs.[7]

In order to respond to this request, Mr. Ungate prepared an analysis of the uncertainty of estimated energy and ancillary services revenues. This analysis is set forth in Attachment 3. Mr. Ungate's analysis proceeds from the assumption that the average of prices in the current month would be the best predictor of prices in the next month. By being proximate in time, the current month would tend to reflect current capacity supply conditions, as well as seasonal variations in capacity markets. To quantify the uncertainty in expected revenues, Mr. Ungate used the average of prices in one month as a prediction of price in the next month, and then compared the variance between the prediction and the actual prices in the following month. The maximum of the monthly downside differences, that is, the month in which the magnitude of the actual monthly average price less the predicted monthly average price was the largest negative value, was used to determine the range of uncertainty. Mr. Ungate's analysis focused on energy revenue uncertainty, since the ancillary services revenues for the units at issue were very limited in amount, and that amount was *de minimis* in relation to the units' energy

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Attachment 2 is filed in both a public version and a version containing confidential, commercially sensitive offer and unit identification information for which confidential treatment is requested as specified above.

[6] Attachment 3, Ungate Aff. ¶¶ 12-14.. In Exhibit D, the numbers for Class H for 2006 have been revised to reflect the inclusion of a unit that at the time of the original report was determined to have sufficiently different cost characteristics from the other units in that Class that it should not be included in Class H. Subsequent data indicates that this unit should be included in Class H for all three years, and Exhibit D is stated on that basis.

[7] April 2 Letter at 2.

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revenues. Thus, inclusion of ancillary services revenues would have had little or no effect on the overall revenue uncertainty.[8]

As shown on Exhibit D of Attachment 3, Mr. Ungate's going-forward costs analysis includes a line item deduction for net revenues. The going-forward costs relevant to the formulation of UCAP offers are those remaining after deduction of net energy and ancillary services revenues.[9] The net revenue determinations are described and supported by Ms. Bouchez.[10]

The results of the revenue uncertainty analysis is also shown on Exhibit D, which shows the results of adjusting the net revenue deductions by the upper end of the range of values resulting from Mr. Ungate's analysis of revenue uncertainty. The resulting adjusted going-forward costs for the summer months and for all months, and excluding the adjustments for risks of Day-Ahead Market bidding and for burning Powder River Basin coal (see above), are higher than the average monthly spot prices in either the Summer or Winter Capability Periods throughout the Relevant Period, except for a small number of MW in May and November 2007. In other words, the average prices during each of the Capability Periods in all but the foregoing months are well inside the range of results produced by Mr. Ungate's analysis of revenue uncertainty. Thus, the results of the revenue uncertainty analysis do not provide a basis for determining a different set of associated market prices in 2006 or 2008.[11]

In May 2007, offers from Class H units at the level of the estimated going-forward costs would have resulted in the clearing of an additional 9.2 MW, which would have caused prices to decrease $0.016. In November 2007, offers from Class H units at the level of the estimated going-forward costs would have resulted in the clearing of an additional 46.8 MW, which would have caused prices to decrease by no more than $0.082.[12] It should be noted that throughout the 2007 Summer Capability Period, an average of only 2 MW was offered by not sold, an essentially *de minimis* amount that is not consistent with a strategy of economic withholding.[13] In the 2007-2008 Winter Capability Period, the monthly average offered but unsold MW increased to 48 MW, but the average price decreased from $3.28 to $1.77, and the

[8] Attachment 4, Bouchez Aff. ¶ 6.

[9] Attachment 3, Ungate Aff. ¶ 22 and 23..

[10] Attachment 4, Bouchez Aff. ¶ 5.

[11] See Appendix A to the NYISO's January 15, 2009 filing in the above dockets.

[12] Attachment 4, Bouchez Aff. ¶ 6.

[13] *See* Attachment 1.

average amount of excess capacity sold above the minimum requirement increased by over 700 MW, facts that are again fundamentally inconsistent with an effective strategy of economic withholding.

3) *Bidding at upper output levels.*

The April 2 Letter states that in its July 25, 2008 filing, the NYISO "state[d] that the ROS ICAP MW that were offered but not sold were generally at the upper output levels of the relevant units."[14] The April 2 Letter asks the NYISO to "explain why the generating units' high-end bids are consistent with competitive bidding behavior. In addition, please explain whether the high-end bids reflect the actual going-forward costs of the associated 'tail-end' portion of the capacity."[15]

It is widely accepted in the electric industry that as a general matter, steam turbine generators can be difficult to control at the upper end of their operating range, and operating them at those output levels can have the following consequences:

- Efficiency decreases (heat rates increase);
- Wear and tear increases, resulting in increased maintenance costs; and
- Outages increase, resulting in opportunity costs both in energy markets (foregone sales) and capacity markets (lower EFORd, resulting in reduced energy sales).

These effects are reflected in the fact that such generators regularly submit offer curves in energy markets in which the offer price increases with output.[16] Such offer curves are a routine feature of the energy and ancillary services offers in the ROS, which have been highly competitive since the formation of the NYISO.[17] All of the classes analyzed by Mr. Ungate except Class B are steam turbines fueled by oil or coal.

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[14] April 2 Letter at 2.

[15] *Id.*

[16] Attachment 4, Bouchez Aff. ¶ 7.For simplicity, unless otherwise indicated references in this section to "energy markets" or "energy offers" should be understood to refer to the markets or offers for both energy and ancillary services.

[17] *See N.Y. Indep. Sys. Operator, Inc.*, 111 FERC ¶ 61,468 (2005) (holding, on the basis of interventions asserting that there had been no showing of any well-defined structural problem

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Under the Services Tariff, ICAP Suppliers have a DAM bidding obligation for the ICAP equivalent of the amount of UCAP sold.[18] To the extent that incurring such an obligation would require offers for upper output levels, and thus the potential to operate at those levels, UCAP offers encompassing a unit's upper output levels entail the risks described above. As also discussed above, the going-forward costs relevant to the formulation of capacity bids are those remaining after the deduction of net energy and ancillary services revenues. Thus, the costs associated with increased operating risks would tend to increase the unit's going-forward costs, to the extent they resulted in costs that were not recovered in the unit's net energy and ancillary services revenues.

A supplier intending to offer capacity from the upper levels of a unit's output would accordingly face a series of business judgments on the recovery of those costs, including quantifying them and assessing the opportunities for their recovery, based on an assessment of conditions in the energy and the capacity markets. As noted above, Mr. Ungate's analysis indicates a significant range of uncertainty associated with the realization of energy and ancillary services revenues. If a supplier believed that it did not or would not recover sufficient revenues in the energy markets, it could seek to increase its capacity offers in recognition of the resulting net increase in unrecovered going-forward costs. Given the competitive conditions prevailing in the ROS capacity market, however, such an offer would have to be at competitive levels to clear. The increased costs (including opportunity costs that relate to a potentially increased forced outage rate) associated with offers at a unit's upper output levels, the lack of structural market problems in the ROS, and the potential uncertainty of energy revenues mean that a higher offer at higher output levels may reflect a supplier's estimation of the offer necessary to recover the total revenues that would cover its operating and going-forward costs. Such an offer would not of itself be evidence of market power or market power abuse.

Additional analysis.

Under the Services Tariff, going-forward costs are relevant to the Installed Capacity markets in New York as an alternative means of calculating a unit-specific offer cap in areas that have been shown to have the structural predicates for the exercise of market power. To date, the structural predicates for the exercise of market power have only been found to exist in

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that would allow the exercise of market power in the ROS, that automated mitigation procedures should not be used in the ROS).

[18] Services Tariff §5.12.7, which provides, in pertinent part, "each Installed Capacity Supplier shall ... on a daily basis: (i) schedule a Bilateral Transaction; (ii) Bid Energy in each hour of the Day-Ahead Market ...; or (iii) notify the ISO of any outages."

New York City. Under § 4.5(c) of Attachment H to the Services Tariff, a going-forward cost analysis could be used to determine the offer cap of an entity that had already been determined to be a Pivotal Supplier.[19] Generalized estimates of going-forward costs are not used to reach conclusions about market conditions or the need for the imposition of limits on a particular supplier's offers. Indeed, the incorporation in Attachment H of an exception to the application of a default offer cap based on an individual unit's ability to show unit-specific going-forward costs that are higher than the default is an implicit recognition of the potential variability of going-forward costs from unit to unit. Moreover, the default offer cap in New York City is not based on a general estimate of going-forward costs, but "the projected clearing price for each Spot Market Auction determined by the NYISO on the basis of the applicable ICAP Demand Curve and the total quantity of Unforced Capacity from all Installed Capacity Suppliers in the New York City Locality for the period covered by the applicable ICAP Spot Market Auction."

These factors suggest that the ability to draw meaningful conclusions about a particular supplier's offers based on generalized estimates of going forward costs is likely to be very limited at best. This is particularly so where, as during the Relevant Period, the amount of offered but unsold capacity was very small relative to the overall amount of capacity in the market. It likely is unrealistic to expect that every offer will be calculated on a theoretically correct basis. In a large market, some bids may reflect misjudgments or miscalculations. If the market does not exhibit the structural predicates for the exercise of market power, such mistakes or misjudgments, even if they result in offers that could be determined to exceed a rigorous, unit-specific determination of going-forward costs, can be tolerated because they will be disciplined by the market. Such offers will not clear if they are not in fact at competitive levels, and the offering supplier will lose revenues and will have every incentive to recalculate its offers more carefully in the future. Correspondingly, the fact that an offer did not clear and could be found to be above a rigorous determination of that unit's going forward costs does not mean that intervention to put limits on the supplier's offers is warranted. As the NYISO's independent Market Advisor, Dr. David Patton, has explained, several structural preconditions

[19] Services Tariff, Attachment H § 4.5(c) and § 2.1 (defining "Mitigated UCAP" to mean UCAP under the Control of a Pivotal Supplier).

must exist before a supplier has both the opportunity and the incentive to engage in a profitable strategy of withholding.[20] As discussed in the NYISO's previous filings in these dockets, none of those conditions exist in the ROS.

Respectfully submitted,

William F. Young
Counsel for
New York Independent System Operator, Inc.

cc: Ms. Katie Williams
Larry D. Gasteiger, Esq.

[20] *See* Affidavit of Dr. David B. Patton in support of the NYISO's October 4, 2007 filing in Docket No. EL07-39-000, ¶ 31 (explaining that a supplier must be pivotal, generally as a result of significant transmission congestion, and be able to earn higher revenues by not selling a portion of that supply and selling its remaining capacity of higher prices).

Attachment 1

Table 1 Breakout of Unoffered and Unsold Capacity MW by type of Market Participant

	Summer 2006		Winter 2006-2007		Summer 2007		Winter 2007-2008		Summer 2008		Winter 2008-2009	
	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW
4 ROS Utilities	**133**	**0**	**112**	**0**	**140**	**0**	**157**	**0**	**106**	**0**	**64**	**0**
	51.30%	0.00%	48.20%	0.00%	55.50%	0.00%	59.25%	0.00%	33.13%	0.00%	28.07%	0.00%
5 ROS GenCo's	**7**	**227**	**71**	**303**	**94**	**2**	**47**	**47**	**68**	**62**	**100**	**247**
	2.80%	94.40%	30.60%	100.00%	37.40%	100.00%	17.74%	97.92%	21.25%	100.00%	43.86%	99.60%
All Others incl. SCRs	**119**	**13**	**49**	**0**	**18**	**0**	**61**	**1**	**146**	**0**	**64**	**1**
	45.90%	5.60%	21.10%	0.00%	7.10%	0.00%	23.02%	2.08%	45.63%	0.00%	28.07%	0.40%
Total Unoffered/ Unsold	**259**	**240**	**232**	**303**	**252**	**2**	**265**	**48**	**320**	**62**	**228**	**248**
Available MW	23311		24509		23292		24164		22980		24050	

Attachment 2 (PUBLIC VERSION - Privileged Information has been Removed from the Document)

Public Version

AUCTION_TYPE	AUCTION_MONTH	LOCATION_DESC	OFFER_CAPA	OFFER_PRICE	PTID_NAME	AWARDED_CAP	MARKET_CLEARING_PRICE
Spot	5/1/2007	ROS	4.1	3.25	Unit_2	0	3.16
Spot	5/1/2007	ROS	5.1	3.2	Unit_1	0	3.16
		Offered	9.2		Awarded	0	
					Unsold	9.2	

Public Version

AUCTION_TYPE	AUCTION_MONTH	LOCATION_DE	OFFER_CAPACI	OFFER_PRICE	PTID_NAME	AWARDED_CAPACIT	MARKET_CLEARING_PRICE
Spot	11/1/2007	ROS	114	1.6	Unit_3	67.186	1.6
Spot	11/1/2007	ROS	29.4	1.6	Unit_4	17.327	1.6
Spot	11/1/2007	ROS	3	1.75	Unit_5	0	1.6
		Offered	146.4		Awarded	84.513	
					Unsold	61.887	

Public Version

AUCTION_	AUCTION_MONT	LOCATION_	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPA(	MARKET_CLEARING_PRICE
Spot	3/1/2008	ROS	3	3.25	Unit_6	0	1.05
Spot	3/1/2008	ROS	8.4	3.25	Unit_5	0	1.05
Spot	3/1/2008	ROS	1.9	1.35	Unit_4	0	1.05
Spot	3/1/2008	ROS	3.9	1.4	Unit_3	0	1.05
Spot	3/1/2008	ROS	2.6	1.45	Unit_2	0	1.05
Spot	3/1/2008	ROS	4.2	1.5	Unit_1	0	1.05
Spot	3/1/2008	ROS	54.4	1.3	Unit_12	0	1.05
Spot	3/1/2008	ROS	170.5	1.25	Unit_11	0	1.05
		Offered	248.9		Awarded	0	
					Unsold	248.9	

Public Version

AUCTION_TYPE	AUCTION_MONT	LOCATION_D	OFFER_CAPACI	OFFER_PRICE	PTID_NAME	AWARDED_CAPACI	MARKET_CLEARING_PRICE
Spot	5/1/2008	ROS	75	2.6	Unit_14	12.041	2.6
		Offered	75		Awarded	12.041	
					Unsold	62.959	

Public Version

AUCTION_TYPE	AUCTION_MONTI	LOCATION_DESCF	OFFER_CAPACII	OFFER_PRICE	PTID_NAME	AWARDED_CAPA(	MARKET_CLEARING_PRICE
Spot	8/1/2008	ROS	39.1	2.7	Unit_7	10.377	2.7
		Offered	39.1		Awarded	10.377	
					Unsold	28.723	

Public Version

AUCTION_T	AUCTION_MC	LOCATION_D	OFFER_CAI	OFFER_PRICE	PTID_NAME	AWARDED_CA	MARKET_CLEARING_PRICE
Spot	9/1/2008	ROS	204.6	2.45	Unit_11	143.378	2.45
Spot	9/1/2008	ROS	119.3	2.5	Unit_10	0	2.45
Spot	9/1/2008	ROS	0.7	2.6	Unit_9	0	2.45
Spot	9/1/2008	ROS	97.3	2.45	Unit_13	68.185	2.45
		Offered	421.9		Awarded	211.563	
					Unsold	210.337	

Public Version

AUCTION_TYPE	AUCTION_MC	LOCATION_D	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_C/	MARKET_CLEARING_PRICE
Spot	10/1/2008	ROS	19.2	2.15	Unit_10	0	1.93
Spot	10/1/2008	ROS	48.5	2	Unit_13	0	1.93
		Offered	67.7		Awarded	0	
					Unsold	67.7	

Public Version

AUCTION_TYPE	AUCTION_MONT	LOCATION_DES(	OFFER_CAPACIT	OFFER_PRICE	PTID_NAME	AWARDED_CAPA(	MARKET_CLEARING_PRICE
Spot	11/1/2008	ROS	64.1	1.25	Unit_8	0	1
Spot	11/1/2008	ROS	123.6	1	Unit_10	44.037	1
Spot	11/1/2008	ROS	58.3	1.3	Unit_9	0	1
Spot	11/1/2008	ROS	104	1.25	Unit_14	0	1
		Offered	350		Awarded	44.037	
					Unsold	305.963	

Public Version

AUCTION_TYPE	AUCTION_MONTH	LOCATION_DESC	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPACI	MARKET_CLEARING_PRICE
Spot	12/1/2008	ROS	123.6	1.25	Unit_10	12.179	1.25
Spot	12/1/2008	ROS	58.3	1.35	Unit_9	0	1.25
Spot	12/1/2008	ROS	18.6	1.35	Unit_12	0	1.25
		Offered	200.5		Awarded	12.179	
					Unsold	188.321	

Attachment 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. Docket Nos. ER01-3001-021, ER01-647-012, ER01-3001-022, and ER01-647-013

AFFIDAVIT OF
CHRISTOPHER D. UNGATE

Mr. Christopher D. Ungate declares:

1) I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Purpose of this Affidavit

2) At the request of the NYISO, acting under my guidance, Sargent & Lundy LLC (S&L) prepared an estimate of the going-forward costs of different classes of generating units in Rest of State (ROS) for 2007 and 2008, and updated its previous analysis for 2006 provided as part of the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011.

3) My affidavit is structured as follows. First, I present my qualifications. Second, I describe the costs that are included in a generator's going-forward costs. Third, I present the methodology for estimating going-forward costs. Fourth, I present the estimated going-forward costs.

II. Qualifications

4) I am a Senior Consultant with Sargent & Lundy LLC and have over thirty years of experience electric utility operations, planning, and consulting. Prior to joining Sargent & Lundy in 2006, my professional work experience included management of generation resource planning for a 30,000 MW portfolio of nuclear, coal, hydro and gas generation, providing annual power supply plans, monthly cost forecast updates, and system reliability analyses; hydro operations business planning; re-engineering and process improvement initiatives in utility planning and operations; and laboratory and prototype testing for hydro and thermal generating plants.

5) My consulting practice at Sargent & Lundy focuses on the areas of integrated resource planning, financial modeling and analysis for the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. I also perform due diligence reviews of new technology development, new projects, modification and refurbishment of existing facilities, asset transactions, and operational assessments.

6) I managed Sargent & Lundy's efforts in support of the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011, and in support of the October 4, 2007, "Compliance Filing of the New York Independent System Operator, Inc., Regarding the New York City ICAP Market Structure," Docket No. EL07-39-000. I prepared an estimate of the going-forward costs of different classes of generating units in the Rest of State (ROS) and in New York City (NYC), respectively, for these filings. I also managed Sargent & Lundy's efforts with respect to the

update of the NYISO Demand Curves. As part of that work, I guided the estimation of capital costs, fixed operations and maintenance costs, and other fixed costs for quantifying the cost of new entry in NYISO Zones J and K, and Rest of State (ROS).

7) My resume is attached as Exhibit A hereto.

III. Definition of Going-Forward Costs

8) A generator's "going-forward" costs are the costs that could be avoided if a unit is mothballed rather than being maintained as an active market participant to provide capacity. By "mothballed," I mean taken out of service for at least one year, but maintained in a condition that, at reasonable cost, it could be returned to service if market conditions warranted. A unit that is not recovering its avoidable going-forward costs would likely be mothballed.

9) Based on our review of the costs of the categories of units described below, the categories of the majority of costs that could be avoided by not supplying capacity are:
    a) Labor for routine operations and maintenance;
    b) Routine materials and contract services,
    c) Administrative and general costs, and
    d) Insurance.

10) Going-forward costs do not include site leasing or land ownership costs, or property taxes except in unusual circumstances. When a unit is mothballed, the land and physical facilities are maintained so that the option of returning the unit to service is preserved. Hence these

costs are not avoidable. If a unit were retired instead of mothballed, site leasing or land ownership costs, and property tax costs, would become avoidable. The types and percentages of costs that are avoidable in a retirement scenario would be case specific. For example, land may be leased and the lease terminated, or the land may be owned and sold. Consequently, the amount of avoidable costs could be significantly different from case to case. Potentially, all of these costs, as well as all of the labor for routine operations and maintenance, routine materials and contract services, administrative and general, and insurance costs, could become avoidable in a retirement scenario.

IV. Methodology for Estimating Going-Forward Costs

11) The methodology used for this estimate was the same as that used for the estimate of going-forward costs in ROS in support of the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011, and in NYC in support of the October 4, 2007,"Compliance Filing of the New York Independent System Operator, Inc., Regarding the New York City ICAP Market Structure," Docket No. EL07-39-000. The focus of this estimate of going-forward costs was ROS generating units whose capacity offers were not accepted in the 2007 and 2008 capability years, and in updating certain adjustments to going forward costs previously estimated for the 2006 capability year. The generating units whose capacity offers were not accepted were natural gas combined cycle cogeneration units, No. 6 fuel oil steam turbine units, sub-critical coal steam turbine units, and coal-fired cogeneration units.

12) I reviewed a list of the principal generating units in ROS provided in the Gold Books applicable to the 2007 and 2008 capability years and maintained by the New York

Independent System Operator, and divided the units into classes based on primary fuel and technology. A number of units fell within the classes of units for which going-forward costs were estimated for ROS and NYC in the previous filings. These classes were:

a) Natural gas combined cycle (Class A)
b) Natural gas combined cycle cogeneration (Class B)
c) Natural gas simple cycle turbine (Class C)
d) No. 2 fuel oil simple cycle turbine (Class D)
e) Kerosene simple cycle turbine (Class E)
f) No. 6 fuel oil steam turbine (Class F)
g) Natural gas steam turbine (Class G)
h) Sub-critical coal steam turbine units (Class H)

13) All of the units whose capacity offers were not accepted in the 2008 capability year, and all but one of the units whose capacity offers were not accepted in the 2007 capability year fell into Classes B, F and H. A new Class (Class I) was formed for coal-fired cogeneration units to include the remaining unit whose capacity offer was not accepted in the 2007 capability year. Other classes could be formed for generating units in ROS because of the diversity of fuel and technologies in this region. These classes were not analyzed for this effort because no generating units whose capacity offers were not accepted in the 2007 and 2008 capability years were found in these classes.

14) The number of units in Classes B, F, H, and I, the average capacity factor, the average in-service date and average summer/winter capacity (ICAP basis) are shown in Exhibit B for 2007 and 2008 (Class I only in 2007). A list of the units included in each class, together with

the data obtained from the applicable Gold Books for each unit, is given in Exhibit C. For reference, Exhibit B includes the corresponding information for capability year 2006 taken from Exhibit B of my affidavit in the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011

15) The general methodology used for the estimation of generator fixed costs was the same as that used for the Cost of New Entry (CONE) determination in the ICAP Demand Curves update analysis; the determination of going-forward costs for generating units in NYC for the October 4, 2007, "Compliance Filing of the New York Independent System Operator, Inc., Regarding the New York City ICAP Market Structure," Docket No. EL07-39-000.; and the determination of going forward costs for generating units in ROS for the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011. The methodology is as follows:

a) The O&M costs for capability year 2006 were derived from a variety of sources, including data from the ICAP Demand Curve reset, the State-of-the-Art Power Plant Combustion Turbine Workstation, v 7.0, developed by the Electric Power Research Institute (EPRI), data for existing plants reported on Federal Energy Regulatory Commission (FERC) Form 1, and confidential data from existing plants. Escalation rates were used to adjust the 2006 cost to 2007 and 2008. Labor costs were escalated using the average of the RS Means Skilled Trade Average for Albany, Syracuse and Buffalo. Other O&M costs were escalated using the Producer Price Index for Electric Power Generation.

b) The methodology for estimating O&M labor costs and A&G expenses assumed a two-unit site. Appropriate adjustments were made to labor and A&G costs to compensate for the economies of scale associated with plant sites with a larger number of units.

c) The going-forward costs for cogeneration units in Class B and Class I were split between power and non-power (usually steam) outputs. Approximately two-thirds of the going-forward costs were assumed to be attributable to power generation.

d) The market value of a generating plant, which was the basis for the insurance calculation, was estimated from the same data sources as for O&M costs, with downward adjustments to account for the average age of plants in each class.

e) The percentage of cost in each cost category that would be saved by mothballing a unit (the avoidable cost) was estimated using percentages published by PJM.[1] These percentages were developed by PJM with stakeholder involvement as part of the development of the Reliability Pricing Model process. Some O&M expenses would be incurred to maintain a mothballed unit so that it could be recovered from mothball status and returned to service. These would include site security, maintenance of rotating equipment on turning gear, compliance with environmental requirements, etc. Some insurance costs could be reduced with the unit not in operable status.

f) Generator avoidable costs were estimated on an annual basis assuming that decisions to mothball a unit would be made for a period of at least one year, if not longer. Recovery of avoidable costs would not all have to occur in any one month. It is assumed that one-

[1] PJM Reliability Pricing Model, Default Avoided Cost Rate Proxy Plants, November 22, 2006.

twelfth of those costs (seasonally adjusted as appropriate) can be recovered in a given month to permit a given unit to remain a capacity supplier for that month.

V. Estimated Going-Forward Costs

16) As shown in Exhibit B, going-forward costs for ROS classes B, F, H and I in capability year 2007 vary from $15.03/kW-year for natural gas combined cycle cogeneration to $55.92 /kW-year for steam electric coal cogeneration. The going-forward costs for ROS classes B, F, and H in capability year 2008 vary from $15.77/kW-year for natural gas combined cycle cogeneration to $47.73/kW-year for sub-critical coal steam turbines. For reference, the going-forward costs for ROS classes B, F and H in capability year 2006 vary from $14.43/kW-year for natural gas combined cycle cogeneration to $54.89/kW-year for sub-critical coal steam turbines.

VI. Estimate of Adjustments to Going-Forward Costs for ROS Generating Units Whose Capacity Offers Were Not Accepted in the 2006, 2007 and 2008 Capability Years

17) I applied the four adjustments to the going-forward costs for capability years 2007 and 2008 that I applied to going forward costs for capability year 2006 in the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011. The owners of ROS generating units whose capacity offers were not accepted in the 2006 capability year claim that these adjustments are needed to include all the costs they consider to be avoidable if a unit were taken out of service for at least one year, but maintained in a condition so that, at reasonable cost, the unit could be returned to service if market conditions warranted. These adjustments do not necessarily

align with the definition of going-forward costs discussed previously and used as the basis for Exhibit B. My approach to estimating the value of the adjustments is summarized in the following four paragraphs.

18) *Costs associated with risks inherent in the Day Ahead Market (DAM) bidding obligation*: The replacement cost for risks inherent in DAM bidding is based on forced outages. I assume that the unit was offered and accepted at full capacity, and then incurs a forced outage for whatever reason. The owners are then obligated to pay for replacement energy. The assumed forced outage rate is the 2007 and 2008 EFORd for the generating units whose capacity offers were not accepted in the 2007 and 2008 capability years, respectively. The cost of replacement energy was based on the average gross energy and ancillary service revenues for these units in the applicable year. I further assumed that owners would recover only half of these costs in the capacity market by including them as going-forward costs.

19) *Costs associated with changes in property tax treatment*: Property taxes are based on the capacity and market value data in Exhibit B and the effective property tax rate for ROS from the recent update of the NYISO Demand Curves. Based on input from owners of generating units whose capacity offers were not accepted in the 2006 capability year, and applying the same input to the 2007 and 2008 capability years, I further assumed that 98 percent of the estimated property taxes would be going-forward costs.

20) *Costs associated with derating of plant output due to burning of Powder River Basin (PRB) coal*: The replacement cost for energy due to burning PRB is based on derates. I assumed that the Class H generating units whose capacity offers were not accepted in the 2007 and 2008 capability years were offered and accepted at full capacity; that their fuel handling

equipment was sized to burn Eastern coals and was designed to have excess capacity so that normal maintenance could be performed on idle equipment while the remaining equipment was operated to keep the unit operating at its maximum capacity; that all of the fuel handling equipment is now fully utilized to burn PRB due to the lower heating value of this fuel--thereby providing inadequate time for equipment maintenance; that some of the fuel handling equipment malfunctions or performs at less than capacity due to the fact that normal maintenance has been deferred; and that plant capacity is derated while the equipment maintenance or repair is performed. Data on the lost generation due to PRB derates was not available for Class H units whose capacity offers were not accepted in the 2007 and 2008 capability years. Based on experience at units with a similar situation, I estimated that the annual lost generation due to all derates would be 1% of total capacity, and that the majority of derates would be caused by issues related to burning PRB. The replacement cost was based on the average gross energy and ancillary service revenues for these units in the applicable year. I further assumed that owners would recover only half of these costs in the capacity market by including them as going-forward costs.

21) *Costs associated with certain maintenance contracts*: The owner of generating units in Class B some of whose capacity offers were not accepted in the 2007 and 2008 capability years has identified a relatively expensive maintenance contract for the units that it considers a going-forward cost because the costs under the contract are set based on the operating levels of the units. Based on information provided by the owner, 95% of the cost of this contract was included as an adjustment.

22) The value of the adjustments to the going-forward costs identified for ROS generating units whose capacity offers were not accepted in the 2007 and 2008 capability years is summarized in Exhibit D. The adjustments are shown on a UCAP basis to allow direct comparison to capacity offers and market prices for capacity. In addition, estimated net revenues for the subject units were provided by NYISO and subtracted from going forward costs. Going-forward costs minus estimated net revenues for capability year 2007 with adjustments vary from \$(49.48)/kW-year for Class H to \$70.73/kW-year for Class I. Summer values range from \$(4.87)/kW-month to \$6.96/kW-month. Winter values range from \$(3.38)/kW-month to \$4.83/kW-month. Going-forward costs minus estimated net revenues for capability year 2008 with adjustments vary from \$(91.74)/kW-year for Class H to \$73.17/kW-year for Class B. Summer values range from \$(9.64)/kW-month to \$7.69/kW-month. Winter values range from \$(5.65)/kW-month to \$4.51/kW-month. Exhibit D includes the corresponding information for capability year 2006 taken from my affidavit in the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011. In Exhibit D, the going-forward costs minus estimated net revenues with adjustments for Class H for capability year 2006 have been revised from a similar attachment to my July 24, 2008 Affidavit, to reflect the inclusion of a unit whose going forward costs at that time was determined to have sufficiently different cost characteristics from the other units in that Class that it should not be included in Class H. Analysis of data for capability years 2007 and 2008 indicates that this unit should be included in Class H for all three years, and Exhibit D is stated on that basis.

23) To comply with FERC's April 2, 2009, request[2], I calculated the change in estimated going forward costs minus estimated net revenues with adjustments excluding the costs associated with risks inherent in the Day Ahead Market (DAM) bidding obligation, and costs associated with derating of plant output due to burning of Powder River Basin (PRB) coal. Exhibit D shows this calculation for capability years 2006, 2007, and 2008. Going-forward costs minus estimated net revenues for capability year 2006 with the property tax and certain maintenance contract cost adjustments, but excluding the Day-Ahead Market bidding and burning Powder River Basin coal cost adjustments, vary from \$(17.67)/kW-year for Class H to \$36.83/kW-year for Class B. Summer values range from \$(1.74)/kW-month to \$3.62/kW-month. Winter values range from \$(1.21)/kW-month to \$2.52/kW-month. Going-forward costs minus estimated net revenues for capability year 2007 with the property tax and certain maintenance contract cost adjustments, but excluding the Day-Ahead Market bidding and burning Powder River Basin coal cost adjustments, vary from \$(72.79)/kW-year for Class H to \$67.04/kW-year for Class I. Summer values range from \$(7.16)/kW-month to \$6.59/kW-month. Winter values range from \$(4.97)/kW-month to \$4.58/kW-month. Going-forward costs minus estimated net revenues for capability year 2008 with the property tax and certain maintenance contract cost adjustments, but excluding the Day-Ahead Market bidding and burning Powder River Basin coal cost adjustments, vary from \$(103.08)/kW-year for Class H to \$71.00/kW-year for Class B. Summer values range from \$(10.83)/kW-month to \$7.46/kW-month. Winter values range from \$(6.35)/kW-month to \$4.37/kW-month.

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[2] Correspondence to William F. Young, Counsel to NYISO, and Gloria Kavanah, Senior Attorney, NYISO, from Larry D. Gasteiger, Director, Division of Tariffs and Market Development – East, FERC, Reference: Compliance Filings Regarding Reports on Installed Capacity Demand Curves, April 2, 2009.

VII. Estimate of Adjustments to Going-Forward Costs minus estimated net revenues to Account for the Uncertainty in Estimating Energy Revenues for ROS Generating Units Whose Capacity Offers Were Not Accepted in the 2006, 2007 and 2008 Capability Years

24) At the request of NYISO, I developed an approach to account for the uncertainty in estimating the energy revenues that a generator owner (at the time it submits an offer into the capacity market) could expect to receive during the applicable capacity delivery month. An owner of a generating unit would be expected to prepare a forecast for monthly revenues (capacity, energy, and ancillary services) and to compare past forecasts to actual revenue received. From the perspective of the owner, the uncertainty in energy revenues could be characterized by the variation in the difference between actual monthly energy revenues and forecasted monthly energy revenues over an historical period.

25) I analyzed monthly average day-ahead prices for energy for September 2005 through December 2008 in the zones in which the units whose capacity offers were not accepted were located. I compared the monthly average energy price per MWh to a forecast based on the energy prices from the preceding one, two, three or four months. I analyzed the resulting differences (actual minus forecast) for each month of capability years 2006, 2007, and 2008. I found that the average of energy prices from the preceding month was the best predictor of prices in the forecast month. Analysis was performed for all hours and peak hours, and for all months and summer months. I used the maximum of the monthly downside differences (i.e., the month when the magnitude of the actual monthly average price minus the predicted monthly average price was most negative) to identify the range of uncertainty.

26) The maximum value of the range of uncertainty in $/MWh was converted to a monthly risk premium ($/kW-mon) using the annual capacity factor for the units whose capacity offer were not accepted and assuming an average of 730 hours per month. I applied risk premiums for peak hours to units with low capacity factors and for all hours to units with high capacity factors. The risk premium for revenue uncertainty was added to the going forward costs minus estimated net revenues with adjustments for property taxes and certain maintenance contracts (i.e., excluding the costs associated with risks inherent in the Day Ahead Market (DAM) bidding obligation, and costs associated with derating of plant output due to burning of Powder River Basin (PRB) coal). I applied the risk premium for revenue uncertainty in summer months to the aforementioned going forward costs minus estimated net revenues with adjustments for summer months, and the risk premium for revenue uncertainty for all months to the average monthly value of the aforementioned going forward costs minus estimated net revenues with adjustments.

27) Exhibit D shows the going-forward costs minus estimated net revenues for capability years 2006, 2007, and 2008 with cost adjustments for property tax, certain maintenance contracts, and energy revenue uncertainty, but excluding cost adjustments for Day-Ahead Market bidding and burning Powder River Basin. The going forward costs minus estimated net revenues with adjustments for capability year 2006 vary from $9.01/kW-mon for Class F to $10.09/kW-mon for Class H in the summer months, and average $8.70/kW-month to $12.50/kW-month for all months. The going forward costs minus estimated net revenues with adjustments for capability year 2007 vary from $(1.79)/kW-mon for Class H to $8.61/kW-mon for Class I in the summer months, and average $(0.70)/kW-month to $7.94/kW-month for all months The going forward costs minus estimated net revenues with

adjustments for capability year 2008 vary from $4.68/kW-mon for Class F to $17.07/kW-mon for Class B in the summer months, and average $4.00/kW-month to $15.52/kW-month for all months.

Further affiant saieth not.

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 therein are true to the best of my knowledge, information, and belief.

CHRISTOPHER D. UNGATE

SUBSCRIBED AND SWORN to before me this 30 day of April, 2009.

Notary Public

My Commission expires: 2/6/2010

MISTY L. REESE
STATE OF TENNESSEE NOTARY PUBLIC
HAMILTON COUNTY

Exhibit A

CHRISTOPHER D. UNGATE
Senior Consultant
Global Energy Consulting

Sargent & Lundy

EDUCATION

University of Tennessee, Master of Business Administration, 1984
Massachusetts Institute of Technology, M.S. Civil Engineering, 1974
Massachusetts Institute of Technology, B. S. Civil Engineering, 1973

REGISTRATIONS

Professional Engineer - Tennessee

EXPERTISE

Resource Planning
Business and Strategic Planning
Business Process Improvement and Re-engineering
Market Analysis and Price Forecasting
Decision Analysis
Asset Valuation and Due Dilligence
Generation Portfolio Analysis
Risk Management

RESPONSIBILITIES

Mr. Ungate develops and evaluates integrated resource plans and associated analyses to identify and evaluate the optimum power supply options. He reviews and evaluates power supply planning and procurement options such as generation options available in the region (potential greenfield or plant expansion options), the viability of siting and permitting new coal, gas or oil-fired generation, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. He also assesses the potential and/or required renewable energy resource options, the state of transmission planning and upgrade programs, recent wholesale prices in the Client's load zone, and the natural gas market and pipeline capacities. He assures consistency with the Client's long-term plans and objectives and Client-specific economic factors (such as standard inflation, inflation, discount, or escalation rates).

Mr. Ungate develops financial models and analyses utilized in the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. He bases the models on appropriate economic, project, operating, and client-specific inputs related to base-case scenarios, as well as associated sensitivity analyses. He also reviews existing financial models and analyses to determine if they are reasonable and appropriate, and to evaluate or develop resulting conclusions and recommendations. He also performs forward pricing analyses and evaluations, system reliability studies, load forecasting, and electric market forecasts and projections in support of power supply planning or other Client needs.

Mr. Ungate also performs due diligence reviews of new technology development, new projects, modifications and refurbishment of existing facilities, asset transactions, and operational assessments. He evaluates and develops plans to optimize the utilization of conventional hydropower plants and pumped storage plants with thermal generating units.

EXPERIENCE

Mr. Ungate has over 30 years of experience in engineering and planning for electric utilities. Prior to joining Sargent & Lundy in 2006, his professional work experience included:

- Manager of generation resource planning, providing annual power supply plans, monthly cost forecast updates, and system reliability analyses.
- Manager of hydro operations business planning.
- Project manager for re-engineering and process improvement initiatives.
- Manager of laboratory and prototype testing for hydro and thermal generating plants.

POWER SUPPLY PLANNING

- Directed supply planning for 30,000 MWs of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. Directed the preparation of power supply plans, and the valuation of capacity additions, major projects, product offerings, and bulk power transactions. Plans provided the basis for purchase and sale decisions; fuel purchase and inventory decisions; and hedging strategies for the commodity book.
- Led the redesign of planning processes to prepare for competitive generation markets. Developed central database; reduced the number of software applications in use; trained analysts in multiple processes and software programs; documented processes and procedures; and implemented a corrective action process to identify and resolve process and content problems. Power supply plans were updated monthly, portfolio risk book was updated daily, and price forecasts were prepared and updated bi-weekly.
- Led environmental controls optimization study to determine least cost approach to meeting CAIR/CAMR requirements for 15,000 MW coal generation portfolio. Alternatives included mothballing of units; increased allowance purchases; modified capital improvement programs; re-powering; and replacement with capacity and energy purchases from gas-fired units. Developed approach that resulted in reduction of projected end of period debt by more than $1 billion.
- Provided cost analysis for product pricing. Determined analytical approach and oversaw analyses to determine value of interruptible products, standby power, customer co-generation, long vs. short term contracts, and dispersed power products.

BUSINESS AND STRATEGIC PLANNING

- Directed business planning for portfolio of 109 conventional hydropower units at 29 sites and four pumped storage units. Portfolio supplies 10-15% of company sales with 5000 MWs of capacity. Forced outage rates, recordable injury incident rates, and reportable environmental events were increasing over the previous six years. Developed a five year business plan to increase resources to facilitate the transition to a process management maintenance strategy, and to integrate plant modernization and automation projects to change technology and workflow at the plants.
- Directed the first reassessment of the operating policies of Tennessee Valley Authority reservoirs since the system was designed in the 1930's. Stakeholders were concerned about water quality issues affecting the reservoirs and about the adverse impact of lake levels on property values and recreation-oriented businesses. Led initiative to redefine operating policies, examine environmental concerns, expand public interest and support, and more effectively meet the needs of multi-state customer base. Directed the development of an operating scheme that preserved hydropower value while improving summer lake levels for recreation and increasing minimum flows for water quality.
- Developed competitive analysis for an electric utility. Customers seeking choice of energy suppliers created need for a credible competitive analysis for electric utility monopoly. Price to customers was above competitive energy suppliers. Loss of customer load would create the risk of not recovering the high fixed costs of generation built to serve former customers. Quantified the competitive threat, and identified the circumstances under which loss of customers was most likely.
- Directed the start-up and management of a watershed management program to produce improved on-the-ground results within the amount funding available. Integrated a staff of 75 scientists, engineers and support staff from two organizations to develop community coalitions in watersheds to fund, staff and implement water quality improvement projects.

PROJECT ENGINEERING

- Directed 40-50 engineers, technicians and building trades conducting laboratory and prototype testing of thermal and hydro plant performance problems. Responsible for daily operating management, laboratory safety, quality assurance, human resources, technology acquisition and facilities management.
- Conducted field tests and physical modeling studies on the effects of thermal generating plants on rivers and reservoirs. Contributed to preparation of several environmental statements impacting authorizations for plant operations and discharge.

MEMBERSHIPS

Board of Examiners, Tennessee Quality Award, 1997-99
American Society of Civil Engineers

PUBLICATIONS

"Resolving Conflicts in Reservoir Operations: Some Lessons Learned at the Tennessee Valley Authority," American Fisheries Society symposium, 1996.

"Tennessee Valley Authority's Clean Water Initiative: Building Partnerships for Watershed Improvement," Journal of Environmental Planning and Management, 39(1), 1996.

"'Equal Consideration' at TVA: Changing System Operations to Meet Societal Needs," Hydro Review, July 1992.

"Reviewing the Role of Hydropower in TVA Reservoir Operations," with Douglas H. Walters, Waterpower '91, An International Conference on Hydropower, Denver, Colorado, 1991.

"TVA's Lake Improvement Plan: Reviewing the Operating Objectives of TVA's Reservoir System," National Conference on Hydraulic Engineering, Nashville, Tennessee, July 1991.

"Tennessee River and Reservoir System Operation and Planning Review, Final Environmental Impact Statement," with TVA staff, December 1990.

"Field and Model Results for Multiport Diffuser Plume," with Charles W. Almquist and William R. Waldrop, American Society of Civil Engineers Specialty Conference on Verification of Mathematical and Physical Models, University of Maryland, August 1978.

"Mixing of Submerged Turbulent Jets at Low Reynolds Number," with Gerhard Jirka and Donald R. F. Harleman, M.I.T. Ralph M. Parsons Laboratory, Report No. 197, February 1975.

Exhibit B

Exhibit B

Annual Avoidable Costs for a Mothballed Unit	Capability Year 2006 (2006$)			Capability Year 2007 (2007$)					Capability Year 2008 (2008$)		
	Class B ROS	Class F ROS	Class H ROS	Class B ROS	Class F ROS	Class H ROS	Class I ROS		Class B ROS	Class F ROS	Class H ROS
Technology	Combined Cycle Cogeneration	Steam Electric	Steam Electric	Combined Cycle Cogeneration	Steam Electric	Steam Electric	Steam Electric Cogeneration		Combined Cycle Cogeneration	Steam Electric	Steam Electric
Primary Fuel	Natural Gas	#6 Fuel Oil	Coal	Natural Gas	#6 Fuel Oil	Coal	Coal		Natural Gas	#6 Fuel Oil	Coal
Total Units in Group	27	6	24	24	6	23	5	6	4	23	5
Operating in 2006	24	6	22	23	6	20	5	6	3	20	5
Dual-Fueled Units in Group	6	4	5	6	4	5	1	4	3	5	1
Average Capacity Factor	17%	19%	62%	12.9%	5.3%	60.0%	41.2%	#	3.0%	60.0%	41.2%
Average In-Service Date	Nov-92	Oct-68	Apr-55	18-Dec-1992	16-Oct-1968	23-May-1957	25-Jul-1978	#	31-May-1973	23-May-1957	25-Jul-1978
Average Plant Performance											
Net Plant Capacity - Summer (MW)	112	501	118	117	503	160	44		529	160	44
Net Plant Capacity - Winter (MW)	128	507	120	135	503	161	43		532	161	43
Net Plant Capacity - Summer/Winter Avg. (MW	120	504	119	126	503	161	44		531	161	44
Fixed O&M Assumptions											
Average Labor Rate, Incl. Benefits ($/hour)	50.00	50.00	50.00	52.05	52.05	52.05	52.05		52.05	52.05	52.05
Number of Operating and Maintenance Staff (f	9.0	32.0	41.0	9.0	32.0	41.0	18.7		21.0	41.0	18.7
Labor - Routine O&M ($/year)	936,000	3,328,000	4,264,000	974,431	3,464,644	4,439,076	2,021,403		2,184,000	4,439,076	2,021,403
Materials and Contract Services - Routine ($/y	900,000	5,800,000	2,138,000	929,545	5,990,404	2,208,187	927,480		3,400,000	2,208,187	927,480
Administrative and General ($/year)	190,000	540,000	713,000	196,237	557,727	736,407	308,816		430,000	736,407	308,816
Other Fixed Cost Assumptions											
Insurance Rate	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%		0.30%	0.30%	0.30%
Market value of plant ($/kW)	800	700	600	1,446	723	826	1,033		700	826	1,033
Insurance ($/year)	191,716	1,057,753	285,109	583,716	1,153,550	374,362	166,575		620,550	374,362	166,575
Avoidable Cost Percentages - Mothball											
Labor - Routine O&M	73.4%	75.4%	88.7%	73.4%	75.4%	88.7%	88.7%		75.4%	88.7%	88.7%
Materials and Contract Services - Routine	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%		90.0%	90.0%	90.0%
Administrative and General	61.4%	80.1%	90.2%	61.4%	80.1%	90.2%	90.2%		80.1%	90.2%	90.2%
Insurance	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%		60.0%	60.0%	60.0%
PJM Category for Percent Avoidable	Combined Cycle Cogeneration Frame B or E	Oil and Gas Steam	Subcritical Coal	Combined Cycle Cogeneration Frame B or E	Oil and Gas Steam	Subcritical Coal	Subcritical Coal		Combined Cycle Cogeneration Frame B or E	Oil and Gas Steam	Subcritical Coal
Avoidable Costs - Mothball ($/year)											
Labor - Routine O&M	686,743	2,510,022	3,782,659	714,940	2,613,062	3,937,971	1,793,187		744,585	2,721,433	4,101,260
Materials and Contract Services - Routine	810,000	5,220,000	1,924,200	836,591	5,391,364	1,987,368	834,732		893,864	5,760,455	2,123,423
Administrative and General	116,679	432,311	642,873	120,509	446,503	663,977	278,428		128,759	477,070	709,433
Insurance	115,030	634,652	171,065	350,229	692,130	224,617	99,945		378,533	642,338	238,865
Total	1,728,452	8,796,985	6,520,797	2,022,270	9,143,078	6,813,934	3,006,292		2,145,741	9,601,296	7,172,980
$/kW-year	**14.43**	**17.47**	**54.80**	**15.03**	**17.19**	**45.12**	**68.32**		**15.77**	**20.79**	**47.73**

Exhibit C

Exhibit C

EXISTING GENERATING FACILITIES

REF. NO.	Owner Operator and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YYYY-MM-DD	Name Plate Rating (KW)	2007 Capability (kilowatts) SUM 2007	WIN 2007	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2006 Net Energy MWh	Capacity Factor	Notes
	2006 Capability Year																					
1010	Alliance Energy NY	Batavia		B	24024	Batavia	037	36	1992-06-01		56,000	65,000	Y	CC			NG			51,980	9.81%	
1011	Alliance Energy NY	Massena		D	23902	Massena	089	36	1992-07-01		81,000	90,200	Y	CC			NG	FO2		25,571	3.41%	
1012	Alliance Energy NY	Ogdensburg		E	24021	Ogdensburg	089	36	1993-11-01		79,000	89,400	Y	CC			NG	FO2		35,500	4.81%	
1013	Alliance Energy NY	Sterling		E	23777	Sherrill	065	36	1991-06-01		54,900	65,300	Y	CC			NG			52,365	9.94%	
1086	Brascan Power - NY	Carr St.-E. Syr		C	24060	Dewitt	067	36	1993-08-01		88,600	104,600	Y	CC			NG			54,107	6.39%	
1296	Dynegy Power Inc.	Independence		C	23800	Scriba	075	36	1994-11-01		947,600	1,092,600	Y	CC			NG			2,779,547	31.10%	
1307	EPCOR	Fort Orange		F	23900	Castleton	083	36	1992-01-01		67,000	73,000	Y	CC			NG			172,294	28.10%	
1318	Fulton Cogen Assoc., L.P.	Fulton Cogen		C	23766	Fulton	075	36	1991-04-01		42,000	47,000	Y	CC			NG			236	0.06%	
1324	Indeck-Corinth LP	Indeck-Corinth		F	23802	Corinth	091	36	1995-07-01		129,300	132,400	Y	CC		Y	NG	FO2		945,516	82.49%	
1325	Indeck-Olean LP	Indeck-Olean		A	23982	Olean	009	36	1993-12-01		79,400	84,800	Y	CC			NG			134,325	18.66%	
1326	Indeck-Oswego LP	Indeck-Oswego		C	23783	Oswego	075	36	1990-05-01		49,300	60,400	Y	CC			NG			12,986	2.70%	
1327	Indeck-Yerkes LP	Indeck-Yerkes		A	23781	Tonawanda	029	36	1990-02-01		47,800	58,300	Y	CC			NG			21,167	4.56%	
1501	New York State Elec. & Gas Corp.	Indeck-Silver Springs		C	23768	Silver Springs	121	36	1991-04-01		50,500	59,500	Y	CC			NG	FO2		64,874	13.49%	
1538	NFR Power, Inc.	Energy Systems North East		A	23901	North East	049	42	1992-08-01		78,800	81,000	Y	CC			NG			28,021	4.00%	
1563	Niagara Mohawk Power Corp.(1)	General Mills Inc		A	23808		029	36	1988-12-01		3,800	4,200	Y	CC			NG			7,070	20.69%	
1569	Niagara Mohawk Power Corp.(1)	Oxbow Power- N.Tonawanda		A	24026	N Tonawanda	029	36	1993-06-01		55,900	60,500	Y	CC			NG			119,497	23.44%	
1632	Niagara Mohawk Power Corp.(2)	Nottingham High School		C	23634		067	36	1988-06-01		0	0	Y	CC			NG			0	0.00%	
1659	NRG Power, Inc.	Ilion (Ret. 12/31/2006)		E	23567	Ilion	043	36	1993-02-01		0	0	Y	CC			NG			35,178	0.00%	
1685	NYSEG Solutions, Inc.	Carthage Energy		E	23857	Carthage	045	36	1991-08-01		56,900	65,900	Y	CC			NG			12,576	2.34%	
1686	NYSEG Solutions, Inc.	South Glens Falls Energy		F	23858	S Glens Falls	091	36	1991-10-01		0	0	Y	CC			NG			30,510	0.00%	
1687	Onondaga Cogeneration, LP	Onondaga Cogen		C	23986		067	36	1993-11-01		78,900	86,900	Y	CC			NG			41,292	5.89%	
1713	Rensselaer Cogeneration, LLC	Rensselaer Cogen		F	23798	Rensselaer	083	36	1993-12-01		79,000	79,000	Y	CC			NG			19,920	2.88%	
1740	Selkirk Cogen Partners, L.P.	Selkirk-I		F	23801	Selkirk	001	36	1992-03-01		79,900	102,800	Y	CC			NG			520,489	66.04%	
1741	Selkirk Cogen Partners, L.P.	Selkirk-II		F	23799	Selkirk	001	36	1994-09-01		275,200	335,700	Y	CC			NG	FO2		1,850,318	69.15%	
1745	TransAlta	Binghamton Cogen		C	23790	Binghamton	007	36	2001-03-01		43,800	49,800	Y	CC			NG	FO2		18,157	4.44%	
1748	WPS Energy	WPS-Beaver Falls		E	23983	Beaver Falls	049	36	1995-03-01		73,900	92,800	Y	CC			NG			16,892	2.31%	
1750	WPS Energy	WPS-Syracuse		C	23985	Syracuse	067	36	1993-09-01		86,400	85,800	Y	CC			NG			12,548	1.66%	
	Class B Averages								1992-11-10		111,854	127,779									17.38%	
1292	Dynegy Power Inc.	Danskammer 1		G	23586	Newburgh	071	36	1951-12-01		62,700	62,500	N	ST	T	A	FO6	NG	FO2	107,371	19.58%	
1299	Dynegy Power Inc.	Danskammer 2		G	23589	Newburgh	071	36	1954-09-01		58,500	61,500	N	ST	T	A	FO6	NG	FO2	74,050	14.09%	
1298	Dynegy Power Inc.	Roseton 1		G	23587	Newburgh	071	36	1974-12-01		607,000	615,500	N	ST	T	A	FO6	NG	FO2	1,687,860	31.52%	
1300	Dynegy Power Inc.	Roseton 2		G	23588	Newburgh	071	36	1974-09-01		605,200	613,700	N	ST	T	A	FO6	NG	FO2	1,808,215	33.87%	
1660	NRG Power, Inc.	Oswego 5		C	23606	Oswego	075	36	1976-02-01		848,300	849,800	N	ST	W	A	FO6			589,348	7.92%	
1661	NRG Power, Inc.	Oswego 6		C	23613	Oswego	075	36	1980-07-01		821,300	836,300	N	ST	W	A	FO6			432,001	5.94%	
	Class F Averages								1968-10-18		500,500	506,883									18.82%	
1001	AES Corp.	Cayuga 1		C	23584	Lansing	109	36	1955-09-01		151,600	151,400	N	ST	T	A	BIT			1,197,205	90.21%	
1002	AES Corp.	Cayuga 2		C	23585	Lansing	109	36	1958-10-01		153,300	153,700	N	ST	T	A	BIT			1,213,463	90.24%	
1005	AES Corp.	Greenidge 3		C	23582	Torrey	123	36	1950-04-01		52,700	54,400	N	ST	W	A	BIT			221,854	47.29%	

Exhibit C

EXISTING GENERATING FACILITIES

REF. NO.	Owner Operator and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YYYY-mm-DD	Name Plate Rating (KW)	2007 Capability (kilowatts) SUM	WIN	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2006 Net Energy MWh	Capacity Factor	Notes
										2007	2007										
1006	AES Corp.	Greenidge 4	C	23583	Torrey	123	36	1953-12-01		105,900	107,700	N	ST	T	A	BIT	WD	NG	677,765	72.44%	
1008	AES Corp.	Westover 7	C	23579	Union	007	36	1944-01-01		43,500	44,700	N	ST	W	A	BIT			186,096	48.69%	
1009	AES Corp.	Westover 8	C	23580	Union	007	36	1951-12-01		82,500	83,700	N	ST	T	A	BIT			617,009	84.78%	
1294	Dynegy Power Inc.	Danskammer 3	G	23590	Newburgh	071	36	1959-10-01		132,200	134,000	N	ST	T	A	BIT	NG	FO2	920,904	78.98%	
1295	Dynegy Power Inc.	Danskammer 4	G	23591	Newburgh	071	36	1967-09-01		236,200	233,500	N	ST	T	A	BIT	NG	FO2	1,450,436	70.50%	
1432	Mirant Corporation	Lovett 4	G	23642	Tomkins Cove	087	36	1966-03-01		167,900	156,700	N	ST	W	A	BIT	NG	FO6	880,779	61.95%	
1433	Mirant Corporation	Lovett 5	G	23593	Tomkins Cove	087	36	1969-04-01		176,200	203,700	N	ST	W	A	BIT	NG	FO6	783,889	45.91%	
1677	NRG Power, Inc.	Dunkirk 1	A	23563	Dunkirk	013	36	1950-11-01		77,200	86,200	N	ST	T	A	BIT			548,593	78.85%	
1678	NRG Power, Inc.	Dunkirk 2	A	23564	Dunkirk	013	36	1950-12-01		76,700	79,900	N	ST	T	A	BIT			531,820	77.54%	
1679	NRG Power, Inc.	Dunkirk 3	A	23565	Dunkirk	013	36	1959-09-01		188,900	187,200	N	ST	T	A	BIT			1,143,780	69.43%	
1680	NRG Power, Inc.	Dunkirk 4	A	23566	Dunkirk	013	36	1960-06-01		179,600	180,200	N	ST	T	A	BIT			1,024,830	65.03%	
1682	NRG Power, Inc.	Huntley 63 (Ret. 12/31/05)	A	23557	Tonawanda	029	36	1942-12-01		0	0	N	ST	D	A	BIT			0	0.00%	
1683	NRG Power, Inc.	Huntley 64 (Ret. 12/31/05)	A	23558	Tonawanda	029	36	1948-12-01		0	0	N	ST	D	A	BIT			0	0.00%	
1684	NRG Power, Inc.	Huntley 65	A	23559	Tonawanda	029	36	1953-12-01		82,000	78,000	N	ST	D	A	BIT			247,298	35.29%	
1685	NRG Power, Inc.	Huntley 66	A	23560	Tonawanda	029	36	1954-12-01		83,000	76,000	N	ST	D	A	BIT			253,208	36.36%	
1686	NRG Power, Inc.	Huntley 67	A	23561	Tonawanda	029	36	1957-12-01		186,000	192,000	N	ST	T	A	BIT			1,139,933	66.86%	
1687	NRG Power, Inc.	Huntley 68	A	23562	Tonawanda	029	36	1958-12-01		186,000	192,000	N	ST	T	A	BIT			1,061,920	63.20%	
1719	Rochester Gas and Electric Corp.	Rochester 7 (Russell 1)	B	23602	Greece	055	36	1948-11-01		46,000	46,000	N	ST	T	A	BIT			89,084	22.10%	
1720	Rochester Gas and Electric Corp.	Rochester 7 (Russell 2)	B	23632	Greece	055	36	1950-11-01		58,300	56,000	N	ST	T	A	BIT			233,043	46.55%	
1721	Rochester Gas and Electric Corp.	Rochester 7 (Russell 3)	B	23549	Greece	055	36	1953-09-01		47,300	55,000	N	ST	T	A	BIT			212,621	47.45%	
1722	Rochester Gas and Electric Corp.	Rochester 7 (Russell 4)	B	23556	Greece	055	36	1957-02-01		79,000	81,000	N	ST	T	A	BIT			449,419	64.13%	
	Class H Averages							1955-04-30		117,909	119,882									61.88%	

2007 Capability Year

REF. NO.	Owner Operator and / or Billing Organization	Station Unit	Zone	PTID	Town	Cnty	St	In-Service Date	Name Plate Rating (KW)	SUM	WIN	Co-Gen Y/N	Unit Type	F T	C S	Type 1	Type 2	Type 3	Net Energy MWh	Capacity Factor	Notes
1542	Niagara Mohawk Power Corp.	Nottingham High School	C	23634		067	36	1988-06-01	200			Y	CC			NG			0	0.0%	
1330	Indeck Energy Services of Silver S	Indeck-Silver Springs	C	23768	Silver Springs	121	36	1991-04-01	56,600	49,800	63,300	Y	CC			NG	FO2		12,899	2.6%	
1709	Sterling Power Partners, L.P.	Sterling	E	23777	Sherrill	065	36	1991-06-01	65,300	50,200	61,600	Y	CC			NG			6,863	1.2%	
1334	Indeck-Yerkes LP	Indeck-Yerkes	A	23781	Tonawanda	029	36	1990-02-01	59,900	49,600	58,000	Y	CC			NG			21,529	4.1%	
1333	Indeck-Oswego LP	Indeck-Oswego	C	23783	Oswego	075	36	1990-05-01	57,400	49,600	61,700	Y	CC			NG			24,474	4.9%	
1716	TransAlta Energy Marketing (U.S.)	Binghamton Cogen	C	23790	Binghamton	007	36	2001-03-01	47,700	42,200	49,300	Y	CC			NG	FO2		1,110	0.3%	
1139	Coral Power, LLC	Rensselaer Cogen	F	23796	Rensselaer	083	36	1993-12-01	103,700	79,000	79,300	Y	CC			NG			17,541	1.9%	
1695	Selkirk Cogen Partners, L.P.	Selkirk-II	F	23799	Selkirk	001	36	1994-09-01	262,600	290,800	329,400	Y	CC			NG	FO2		1,410,303	61.3%	
1137	Dynegy Power Inc.	Independence	C	23800	Scriba	075	36	1994-11-01	1,254,000	944,400	1,066,800	Y	CC			NG			2,387,969	21.7%	
1694	Selkirk Cogen Partners, L.P.	Selkirk-I	F	23801	Selkirk	001	36	1992-03-01	95,000	80,900	103,800	Y	CC			NG			449,915	54.1%	
1331	Indeck-Corinth LP	Indeck-Corinth	F	23802	Corinth	091	36	1995-07-01	147,000	131,200	132,300	Y	CC		Y	NG	FO2		520,654	40.4%	
1530	Niagara Mohawk Power Corp.	General Mills Inc	A	23808		029	36	1988-12-01	3,800	3,200	4,300	Y	CC			NG			4,428	13.3%	
1654	NYSEG Solutions, Inc.	Carthage Energy	E	23857	Carthage	045	36	1991-08-01	62,900	57,200	65,100	Y	CC			NG			25,110	4.6%	
1711	TransCanada Power Marketing, Lt	Fort Orange	F	23900	Castleton	083	36	1992-01-01	72,000	64,000	73,000	Y	CC			NG			227,357	36.0%	
1140	Energy Systems North East LLC	Energy Systems North Eas	A	23901	North East	049	42	1992-08-01	88,200	74,300	87,700	Y	CC			NG			23,620	3.1%	
1661	Power City Partners, L.P.	Massena	D	23902	Massena	089	36	1992-07-01	101,800	82,200	92,300	Y	CC			NG	FO2		12,726	1.4%	
1332	Indeck-Olean LP	Indeck-Olean	A	23982	Olean	009	36	1993-12-01	90,800	78,500	86,200	Y	CC			NG			242,211	30.5%	

Exhibit C

EXISTING GENERATING FACILITIES

REF. NO.	Owner Operator and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YYYY-MM-DD	Name Plate Rating (KW)	2007 Capability (kilowatts) SUM 2007	WIN 2007	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Fuel Type 2	Fuel Type 3	2006 Net Energy MWh	Capacity Factor	Notes
1717	WPS Energy Services, Inc.	WPS-Beaver Falls	E	23983	Beaver Falls	049	36	1995-03-01	107,800	78,900		Y	CC			NG			57,670	6.1%	
1718	WPS Energy Services, Inc.	WPS-Syracuse	C	23985	Syracuse	067	36	1993-09-01	102,700	86,000	92,500	Y	CC			NG			66,474	7.4%	
1656	Onondaga Cogeneration, LP	Onondaga Cogen	C	23986	Geddes	067	36	1993-11-01	105,800	78,300	87,100	Y	CC			NG			9,130	1.0%	
1010	AG Energy, L.P.	Ogdensburg (Retired - 10/'	E	24021	Ogdensburg	089	36	1993-11-01	99,300			Y	CC			NG	FO2		631	0.1%	
1669	Seneca Power Partners, L.P.	Batavia	B	24024	Batavia	037	36	1992-06-01	67,300	52,400	60,600	Y	CC			NG			18,371	3.1%	
1639	Niagara Mohawk Power Corp.	Fortistar - N.Tonawanda	A	24026	N Tonawanda	029	36	1993-06-01	55,300	53,800	63,300	Y	CC			NG			24,361	5.0%	
1092	Carr Street Generating Station LP	Carr St.-E. Syr	C	24060	Dewitt	067	36	1993-08-01	122,600	89,000	102,700	Y	CC			NG			55,196	5.1%	
	Class B Averages							1992-12-18	134,563	116,568	135,300									12.9%	
1131	Dynegy Power Inc.	Danskammer 1	G	23586	Newburgh	071	36	1951-12-01	72,000	65,500	66,000	N	ST	T	A	FO6	NG	FO2	28,899	4.6%	
1136	Dynegy Power Inc.	Roseton 1	G	23587	Newburgh	071	36	1974-12-01	621,000	614,800	612,000	N	ST	T	A	FO6	NG	FO2	375,420	6.9%	
1138	Dynegy Power Inc.	Roseton 2	G	23588	Newburgh	071	36	1974-09-01	621,000	604,000	606,800	N	ST	T	A	FO6	NG	FO2	681,321	12.5%	
1132	Dynegy Power Inc.	Danskammer 2	G	23589	Newburgh	071	36	1954-09-01	73,500	61,700	61,200	N	ST	T	A	FO6	NG	FO2	30,861	4.8%	
1649	NRG Power, Inc.	Oswego 5	C	23606	Oswego	075	36	1976-02-01	901,800	843,500	841,200	N	ST	W	A	FO6			158,866	2.0%	
1650	NRG Power, Inc.	Oswego 6	C	23613	Oswego	075	36	1980-07-01	901,800	825,500	829,700	N	ST	W	A	FO6			88,733	1.1%	
	Class F Averages							1968-10-16	531,850	502,500	502,817									5.3%	
1675	Rochester Gas and Electric Corp.	Russell 2 (Retired - 2/15/2	B	23532	Greece	055	36	1950-11-01	62,500			N	ST	T	A	BIT			330,407	60.3%	
1007	AES Corp.	Somerset	A	23543	Somerset	063	36	1984-08-01	655,100	686,500	685,400	N	ST	W	A	BIT			5,609,369	97.7%	
1676	Rochester Gas and Electric Corp.	Russell 3	B	23549	Greece	055	36	1953-09-01	62,500	41,700	48,500	N	ST	T	A	BIT			257,004	46.9%	
1677	Rochester Gas and Electric Corp.	Russell 4	B	23556	Greece	055	36	1957-02-01	81,600	77,700	80,200	N	ST	T	A	BIT			422,582	59.1%	
1644	NRG Power, Inc.	Huntley 65 (Retired 6/2/20	A	23559	Tonawanda	029	36	1953-12-01	100,000			N	ST	D	A	BIT			107,845	12.3%	
1645	NRG Power, Inc.	Huntley 66 (Retired 6/2/20	A	23560	Tonawanda	029	36	1954-12-01	100,000			N	ST	D	A	BIT			128,409	14.7%	
1646	NRG Power, Inc.	Huntley 67	A	23561	Tonawanda	029	36	1957-12-01	218,000	194,500	198,000	N	ST	T	A	BIT			1,203,776	63.0%	
1647	NRG Power, Inc.	Huntley 68	A	23562	Tonawanda	029	36	1958-12-01	218,000	190,000	192,000	N	ST	T	A	BIT			1,157,795	60.6%	
1639	NRG Power, Inc.	Dunkirk 1	A	23563	Dunkirk	013	36	1950-11-01	80,000	79,200	81,100	N	ST	T	A	BIT			540,496	77.1%	
1640	NRG Power, Inc.	Dunkirk 2	A	23564	Dunkirk	013	36	1950-12-01	80,000	84,200	80,800	N	ST	T	A	BIT			540,936	77.2%	
1641	NRG Power, Inc.	Dunkirk 3	A	23565	Dunkirk	013	36	1959-09-01	200,000	196,000	196,600	N	ST	T	A	BIT			1,283,778	73.3%	
1642	NRG Power, Inc.	Dunkirk 4	A	23566	Dunkirk	013	36	1960-08-01	200,000	197,100	192,100	N	ST	T	A	BIT			1,089,779	62.2%	
1008	AES Corp.	Westover 7	C	23579	Union	007	36	1944-01-01	75,000	40,700	42,400	N	ST	W	A	BIT			33,560	5.1%	
1009	AES Corp.	Westover 8	C	23580	Union	007	36	1951-12-01	43,800	80,900	84,000	N	ST	T	A	BIT			591,646	154.2%	
1005	AES Corp.	Greenidge 3	C	23582	Torrey	123	36	1950-04-01	50,000	52,700	52,500	N	ST	W	A	BIT			44,897	10.2%	
1006	AES Corp.	Greenidge 4	C	23583	Torrey	123	36	1953-12-01	112,000	105,200	102,500	N	ST	T	A	BIT	WD	NG	652,869	66.5%	
1001	AES Corp.	Cayuga 1	C	23584	Lansing	109	36	1955-09-01	167,200	151,100	154,100	N	ST	T	A	BIT			1,092,264	74.6%	
1002	AES Corp.	Cayuga 2	C	23585	Lansing	109	36	1958-10-01	155,300	154,700	153,600	N	ST	T	A	BIT			1,165,327	85.7%	
1133	Dynegy Power Inc.	Danskammer 3	G	23590	Newburgh	071	36	1959-10-01	147,100	137,200	140,000	N	ST	T	A	BIT	NG	FO2	997,456	77.4%	
1134	Dynegy Power Inc.	Danskammer 4	G	23591	Newburgh	071	36	1967-09-01	239,400	232,200	234,500	N	ST	T	A	BIT	NG	FO2	1,561,230	74.4%	
1439	Mirant Corporation	Lovett 5	G	23593	Tomkins Cove	087	36	1969-04-01	200,600	182,900	185,200	N	ST	W	A	BIT	NG	FO6	1,100,500	62.6%	
1674	Rochester Gas and Electric Corp.	Russell 1 (Retired - 1/31/2	B	23602	Greece	055	36	1948-11-01	46,000			N	ST	T	A	BIT			211,766	52.6%	
1438	Mirant Corporation	Lovett 4 (Retired 5/9/2007;	G	23642	Tomkins Cove	087	36	1966-03-01	179,500			N	ST	W	A	BIT	NG	FO6	172,794	11.0%	
	Class H Averages							1957-05-23	151,026	160,250	161,417									60.0%	

Exhibit C

EXISTING GENERATING FACILITIES

REF. NO.	Owner Operator and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YYYY-MM-DD	Name Plate Rating (KW)	2007 Capability (kilowatts) SUM 2007	WIN 2007	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2008 Net Energy MWh	Capacity Factor	Notes
1341	Jamestown, City of	Jamestown 5		A	1658	Jamestown	013	36	1951-08-01	28,700	23,016	23,486	Y	ST			BIT			140,079	55.7%	
1342	Jamestown, City of	Jamestown 6		A	1658	Jamestown	013	36	1968-08-01	25,000	20,048	20,459	Y	ST			BIT				0.0%	
1122	Coral Power, LLC	Fort Drum		E	23780	Watertown	045	36	1989-07-01	58,000	55,500	56,200	Y	ST			BIT			440,978	86.8%	
1712	Trigen-Syracuse Energy Corp.	Trigen-Syracuse		C	23856	Syracuse	067	36	1991-08-01	101,100	72,100	84,200	Y	ST			BIT	FO2		247,805	28.0%	
1129	Coral Power, LLC	Niagara		A	23895	Niagara Falls	063	36	1991-08-01	56,000	50,100	50,200	Y	ST			BIT			173,981	35.5%	
	Class I Averages								1978-07-25	53,760	44,153	42,909									41.2%	
	2008 Capability Year																					
1082	Carr Street Generating Station LP	Carr St.-E. Syr		C	24060	Dewitt	067	36	1993-08-01	122,600	86,000	102,600	Y	CC			NG			28,863	2.7%	
1126	Dynegy Power Marketing, Inc.	Independence		C	23800	Scriba	075	36	1994-11-01	1,254,000	954,400	1,105,800	Y	CC			NG			1,201,186	10.9%	
1129	Energy Systems North East LLC	Energy Systems North Eas		A	23901	North East	049	42	1992-08-01	88,200	74,500	83,700	Y	CC			NG			10,077	1.3%	
1136	EPCOR Energy Marketing (US) In	Fort Orange		F	23900	Castleton	083	36	1992-01-01	72,000	62,100	70,900	Y	CC			NG			84,787	13.4%	
1312	Hess Corporation	Binghamton Cogen		C	23790	Binghamton	007	36	2001-03-01	47,700	40,900	49,400	Y	CC			NG	FO2		1,744	0.4%	
1313	Indeck Energy Services of Silver S	Indeck-Silver Springs		C	23768	Silver Springs	121	36	1991-04-01	56,600	50,100	64,200	Y	CC			NG	FO2		6,662	1.3%	
1314	Indeck-Corinth LP	Indeck-Corinth		F	23802	Corinth	091	36	1995-07-01	147,000	129,300	132,000	Y	CC		Y	NG	FO2		810,701	63.0%	
1315	Indeck-Olean LP	Indeck-Olean		A	23982	Olean	009	36	1993-12-01	90,600	77,800	86,000	Y	CC			NG			288,683	36.4%	
1316	Indeck-Oswego LP	Indeck-Oswego		C	23783	Oswego	075	36	1990-05-01	57,400	51,100	63,000	Y	CC			NG			11,341	2.3%	
1317	Indeck-Yerkes LP	Indeck-Yerkes		A	23781	Tonawanda	029	36	1990-02-01	59,900	49,700	57,900	Y	CC			NG			6,895	1.3%	
1322	Integrys Energy Services, Inc.	Beaver Falls		E	23983	Beaver Falls	049	36	1995-03-01	107,800	80,200	86,200	Y	CC			NG			11,224	1.2%	
1324	Integrys Energy Services, Inc.	Syracuse		C	23985	Syracuse	067	36	1993-09-01	102,700	85,800	92,500	Y	CC			NG			23,405	2.6%	
1509	Niagara Mohawk Power Corp.	Fortistar - N.Tonawanda		A	24026	N Tonawanda	029	36	1993-06-01	55,300	52,000	62,100	Y	CC			NG			12,618	2.6%	
1510	Niagara Mohawk Power Corp.	General Mills Inc		A	23808		029	36	1988-12-01	3,800			Y	CC			NG			2,306	6.9%	
1576	Niagara Mohawk Power Corp.	Nottingham High School		C	23634		067	36	1988-06-01	200			Y	CC			NG			0	0.0%	
1641	NYSEG Solutions, Inc.	Carthage Energy		E	23857	Carthage	045	36	1991-08-01	62,900	56,900	66,800	Y	CC			NG			4,779	0.9%	
1642	Onondaga Cogeneration, LP	Onondaga Cogen (Retired		C	23986	Geddes	067	36	1993-11-01	105,800			Y	CC			NG			0	0.0%	
1647	Power City Partners, L.P.	Massena		D	23902	Massena	089	36	1992-07-01	101,800	81,400	92,000	Y	CC			NG	FO2		3,811	0.4%	
1677	Selkirk Cogen Partners, L.P.	Selkirk-I		F	23801	Selkirk	001	36	1992-03-01	95,000	77,600	107,000	Y	CC			NG			457,754	55.0%	
1678	Selkirk Cogen Partners, L.P.	Selkirk-II		F	23799	Selkirk	001	36	1994-09-01	262,600	291,300	332,400	Y	CC			NG	FO2		1,578,349	68.6%	
1682	Seneca Power Partners, L.P.	Batavia		B	24024	Batavia	037	36	1992-06-01	67,300	50,100	62,100	Y	CC			NG			5,220	0.9%	
1700	Shell Energy North America (US),	Rensselaer Cogen		F	23796	Rensselaer	083	36	1993-12-01	103,700	79,000	81,300	Y	CC			NG			4,924	0.5%	
1701	Sterling Power Partners, L.P.	Sterling		E	23777	Sherrill	065	36	1991-06-01	65,300	50,600	63,900	Y	CC			NG			4,093	0.7%	
	Class II Averages								1992-12-04	136,096	124,040	143,080								198,210	11.9%	
1120	Dynegy Power Marketing, Inc.	Danskammer 1		G	23586	Newburgh	071	36	1951-12-01	72,000	67,000	66,700	N	ST	T	A	FO6	NG	FO2	5,903	0.9%	
1127	Dynegy Power Marketing, Inc.	Roseton 1		G	23587	Newburgh	071	36	1974-12-01	621,000	614,500	618,500	N	ST	T	A	FO6	NG	FO2	145,620	2.7%	
1128	Dynegy Power Marketing, Inc.	Roseton 2		G	23588	Newburgh	071	36	1974-09-01	621,000	605,700	610,500	N	ST	T	A	FO6	NG	FO2	300,983	5.5%	
1121	Dynegy Power Marketing, Inc.	Danskammer 2		G	23589	Newburgh	071	36	1954-09-01	73,500	61,700	63,200	N	ST	T	A	FO6	NG	FO2	6,920	1.1%	
1636	NRG Power Marketing LLC	Oswego 5		C	23606	Oswego	075	36	1976-02-01	901,800	837,700	851,700	N	ST	W	A	FO6			42,957	0.5%	
1637	NRG Power Marketing LLC	Oswego 6		C	23613	Oswego	075	36	1980-07-01	901,800	833,200	843,500	N	ST	W	A	FO6			48,941	0.6%	
1325	International Paper Company	Ticonderoga Mill		F	23804	Ticonderoga	031	36	1970-01-01	42,100	7,600	7,700	Y	ST			FO6			100	0.0%	

Exhibit C

EXISTING GENERATING FACILITIES

REF. NO.	Owner Operator and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YYYY-MM-DD	Name Plate Rating (KW)	2007 Capability (kilowatts) SUM 2007	WIN 2007	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2008 Net Energy MWh	Capacity Factor	Notes
	Class F Averages							1968-12-18	461,886	432,486	437,400								78,772	1.6%	
1658	Rochester Gas and Electric Corp.	Russell 2 (Retired - 2/15/2	B	23532	Greece	055	36	1950-11-01	62,500			N	ST	T	A	BIT			40,186	7.3%	
1007	AES Eastern Energy, LP	Somerset	A	23543	Somerset	063	36	1984-08-01	655,100	682,800	682,800	N	ST	W	A	BIT			5,232,866	91.2%	
1659	Rochester Gas and Electric Corp.	Russell 3 (Retired 4/24/20	B	23549	Greece	055	36	1953-09-01	62,500			N	ST	T	A	BIT			92,077	16.8%	
1660	Rochester Gas and Electric Corp.	Russell 4 (Retired 4/1/200	B	23556	Greece	055	36	1957-02-01	81,600			N	ST	T	A	BIT			107,726	15.1%	
1633	NRG Power Marketing LLC	Huntley 67	A	23561	Tonawanda	029	36	1957-12-01	218,000	187,200	190,000	N	ST	T	A	BIT			1,233,783	64.6%	
1634	NRG Power Marketing LLC	Huntley 68	A	23562	Tonawanda	029	36	1958-12-01	218,000	186,000	190,000	N	ST	T	A	BIT			1,192,950	62.5%	
1628	NRG Power Marketing LLC	Dunkirk 1	A	23563	Dunkirk	013	36	1950-11-01	80,000	78,400	77,000	N	ST	T	A	BIT			556,102	79.2%	
1629	NRG Power Marketing LLC	Dunkirk 2	A	23564	Dunkirk	013	36	1950-12-01	80,000	78,400	75,600	N	ST	T	A	BIT			591,196	84.4%	
1630	NRG Power Marketing LLC	Dunkirk 3	A	23565	Dunkirk	013	36	1959-09-01	200,000	189,600	186,500	N	ST	T	A	BIT			1,274,208	72.7%	
1631	NRG Power Marketing LLC	Dunkirk 4	A	23566	Dunkirk	013	36	1960-08-01	200,000	188,400	186,600	N	ST	T	A	BIT			1,282,783	73.2%	
1008	AES Eastern Energy, LP	Westover 7	C	23579	Union	007	36	1944-01-01	75,000	40,200	40,900	N	ST	W	A	BIT			5,515	0.8%	
1009	AES Eastern Energy, LP	Westover 8	C	23580	Union	007	36	1951-12-01	43,800	80,900	82,200	N	ST	T	A	BIT			492,424	128.3%	
1005	AES Eastern Energy, LP	Greenidge 3	C	23582	Torrey	123	36	1950-04-01	50,000	52,000	48,200	N	ST	W	A	BIT			36,867	8.4%	
1006	AES Eastern Energy, LP	Greenidge 4	C	23583	Torrey	123	36	1953-12-01	112,000	103,500	104,100	N	ST	T	A	BIT	WD	NG	671,519	68.4%	
1001	AES Eastern Energy, LP	Cayuga 1	C	23584	Lansing	109	36	1955-09-01	167,200	152,300	154,200	N	ST	T	A	BIT			1,090,337	74.4%	
1002	AES Eastern Energy, LP	Cayuga 2	C	23585	Lansing	109	36	1958-10-01	156,300	153,800	156,200	N	ST	T	A	BIT			1,087,990	80.0%	
1122	Dynegy Power Marketing, Inc.	Danskammer 3	G	23590	Newburgh	071	36	1959-10-01	147,100	132,000	134,200	N	ST	T	A	BIT	NG	FO2	1,002,316	77.8%	
1123	Dynegy Power Marketing, Inc.	Danskammer 4	G	23591	Newburgh	071	36	1967-09-01	239,400	235,200	236,500	N	ST	T	A	BIT	NG	FO2	1,664,222	79.4%	
1411	Mirant Energy Trading, LLC	Lovett 5 (Retired - 4/30/20	G	23593	Tomkins Cove	087	36	1969-04-01	200,600			N	ST	W	A	BIT	NG	FO6	265,142	16.2%	
1657	Rochester Gas and Electric Corp.	Russell 1 (Retired - 1/31/2	B	23602	Greece	055	36	1948-11-01	46,000			N	ST	T	A	BIT			18,447	4.6%	
1724	Trigen-Syracuse Energy Corp.	Syracuse Energy ST2	C	#####	Syracuse	067	36	1991-08-01	62,000	58,900	58,500	N	ST			BIT	FO2			0.0%	
	Class H Averages							1958-11-19	150,290	162,800	162,656								897,862	68.2%	

Exhibit D

Owner's Adjustments to Going Forward Costs

	Capability Year 2006 (2006$)			Capability Year 2007 (2007$)				Capability Year 2008 (2008$)		
	Class B ROS	*Class F* ROS	*Class H* ROS	*Class B* ROS	*Class F* ROS	*Class H* ROS	*Class I* ROS	*Class B* ROS	*Class F* ROS	*Class H* ROS
Technology **Primary Fuel**	Combined Cycle Cogeneration Natural Gas	Steam Electric #6 Fuel Oil	Steam Electric Coal	Combined Cycle Cogeneration Natural Gas	Steam Electric #6 Fuel Oil	Steam Electric Coal	Steam Electric Cogeneratio Coal	Combined Cycle Cogeneration Natural Gas	Steam Electric #6 Fuel Oil	Steam Electric Coal
Avoidable Costs - Mothball ($/kW-yr) - ***from Exhibit B***	14.43	17.47	54.89	15.03	17.19	45.12	55.92	15.77	20.79	47.73
Avoidable Costs - Mothball ($/kW-yr) - UCAP basis[1]	15.25	18.47	58.04	15.72	17.98	47.19	58.49	16.56	21.83	50.12
Net Revenues ($/kW-yr) - Actual	12.81	2.30	92.30	6.41	(4.26)	136.92	12.63	(13.17)	6.39	171.38
Avoidable Costs minus Net Revenues ($/kW-yr)	2.44	16.17	(34.26)	9.31	22.24	(89.73)	45.87	29.73	15.44	(121.26)
Adjustments based on Inputs from owners ($/kW-yr):										
Add risk premium for DAM bidding obligation[2]	0.06	1.35	11.87	0.29	0.05	21.46	3.69	2.16	1.49	9.99
Add property tax	16.58	14.51	16.58	29.65	14.82	16.94	21.18	31.80	15.90	18.17
Add risk premium for PRB derates[2]			1.67			1.85				1.35
Add maintenance contract	17.81			18.23				18.94		
Adjusted Avoidable Costs minus Net Revenues ($/kW-yr)	36.90	32.02	(4.13)	57.47	37.12	(49.48)	70.73	73.17	32.83	(91.74)
Summer ($/kW-mon)	3.83	3.15	(0.41)	5.65	3.66	(4.87)	6.96	7.69	3.45	(9.64)
Winter ($/kW-mon)	2.52	2.19	(0.28)	3.93	2.54	(3.36)	4.83	4.51	2.02	(5.65)
Deduct risk premiums for DAM bidding obligation and PRB Derates										
Adjusted Avoidable Costs minus Net Revenues ($/kW-yr)	36.83	30.67	(17.67)	57.18	37.07	(72.79)	67.04	71.00	31.34	(103.06)
Summer ($/kW-mon)	3.82	3.02	(1.74)	5.62	3.66	(7.16)	6.59	7.46	3.29	(10.83)
Winter ($/kW-mon)	2.52	2.10	(1.21)	3.91	2.53	(4.97)	4.58	4.37	1.93	(6.35)
Add risk premium for Revenue Uncertainty										
Adjustments based on uncertainty of monthly revenues ($/kW-mon):										
Risk premium for summer months	5.47	5.99	11.62	1.56	0.11	5.37	2.01	9.61	1.39	16.21
Risk premium for all months	6.79	6.14	13.97	1.83	0.13	5.37	2.35	9.61	1.39	16.21
Adjusted Avoidable Costs minus Net Revenues ($/kW-mon)										
Summer	9.09	9.01	10.09	7.19	3.76	(1.79)	8.61	17.07	4.68	5.38
All Months	9.86	8.70	12.50	6.59	3.22	(0.70)	7.94	15.52	4.00	7.62

Notes

1. All remaining values in Exhibit D also are on a UCAP basis
2. Assumes that half of the risk is recovered in the capacity market

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket Nos.** ER01-3001-021, ER01-3001-022, ER03-647-012, and ER03-647-013.

AFFIDAVIT OF NICOLE BOUCHEZ, PH.D.

Qualifications and Purpose

1. My name is Nicole Bouchez. I am the Manager, Market Monitoring & Performance, for the New York Independent System Operator, Inc. ("NYISO"). My responsibilities include administering Attachment H of the NYISO OATT and the NYISO's Market Monitoring Plan. I have worked as an Energy Economist for six years and I have held this position for two years.

2. I hold a Ph.D. and a M.A. in International Economics from the University of California, Santa Cruz and a B.A. in Economics and International Relations from the University of California, Davis..

3. The information described below that is included or referred to in the NYISO's response (the "Response") to the requests for information set forth in the Deficiency Letter issued in the above dockets dated April 2, 2009 ("April 2 Letter"), was gathered or prepared by me or under my supervision.

4. Attachment 2 to the Response is a spreadsheet setting forth the installed capacity offers of and awards to ICAP suppliers in the Rest of State[1] area ("ROS") of New York that made offers of Unforced Capacity ("UCAP") that were not accepted during the period relevant to the April 2 Letter (Calendar Year 2006, 2007 and 2008) ("Relevant Period"). This information was determined by me or under my supervision from the books and records of the NYISO.

5. The net revenues and summer/winter adjustments shown on Exhibit D to Mr. Ungate's affidavit submitted with the Response were determined by me or under my supervision from the books and records of the NYISO, and are accurately reflected on Exhibit D. The net revenues are estimated based on the estimate of energy and ancillary services revenues less the relevant cost based reference level information for the relevant ROS ICAP suppliers (or for a similar unit if the unit did not provide the NYISO with cost information) with capacity offered but not sold in the Relevant Period. The estimate of energy and ancillary service revenues was determined based on historic revenues, using data from the NYISO's billing codes that encompass the vast majority of energy and ancillary services. The billing codes that were excluded are those that either were not likely to be incurred or received by these categories of generators, or they were *de minimis*.

6. The Response includes a description of the price effects resulting from an analysis performed by Mr. Ungate of the uncertainty in estimating energy and ancillary services

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[1] Unless otherwise specified, capitalized terms have the meanings specified in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff").

revenues. The uncertainty of energy and ancillary services revenues was analyzed. The uncertainty analysis included an adjustment for energy revenues but did not incorporate an adjustment for ancillary services revenues because the ancillary services revenues were very limited in amount, and such amount was *de minimis* in relation to the energy component of the bill, and would not have informed the results or the conclusions. The prices and price effects in that section of the Response were determined by me or under my supervision from the books and records of the NYISO. In May 2007, 9.2 MWs unsold would have had a $0.016 impact on prices. In November 2007, 46.8 MWs of unsold capacity would have had, at most, a $0.082 impact on prices.

7. The Response states that generators regularly submit offer curves in the NYISO energy markets in which the offer price increases with output, and that such monotonically increasing bids are required and are a routine feature of the energy offers. The statements are accurate descriptions of the bids submitted in the NYISO markets.

ATTESTATION

I am the witness identified in the foregoing Affidavit of Nicole Bouchez dated May 4, 2009 (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Nicole Bouchez, Ph.D.
Manager, Market Monitoring & Performance
New York Independent System Operator, Inc.

May 4, 2009

Subscribed and sworn to before me
this 4th day of May, 2009

Diane L Egan
Notary Public

DIANE L. EGAN
Notary Public, State of New York
Qualified in Schenectady County
No. 4924890
Commission Expires March 21, 20 10

My commission expires: March 21, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Public Version of the Response on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC, this 4th day of May, 2009.

Wm. F. Young

Hunton & Williams LLP
1900 K Street, NW
Washington, DC 20426
(202) 955-1500

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Begin Non-Public

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