DEC Staff Fact Sheet on Scheduled BTA Outages/Seasonal Protective Outages

Introduction:

Pursuant to the Memorandum Ruling of DEC Administrative Law Judge Maria E. Villa dated October 18, 2013 in the Entergy Indian Point SPDES permit renewal and modification proceeding ("Memorandum Ruling"), the following information is provided as the Department's "fact sheet" with respect to DEC staff's proposal for permanent annual outages at Indian Point Energy Center Unit's 2 and 3 ("IPEC") as a best technology available ("BTA") alternative in order for the facilities' cooling water intake structures ("CWIS") to meet the requirements of 6 NYCRR §704.5 (*see* Memorandum Ruling at p. 8).

This fact sheet sets forth the potential efficacy and costs of seasonal protective outages (*i.e.*, "scheduled outages") as a BTA alternative that could be implemented at IPEC in the event that Department staff's preferred BTA alternative (as reflected in the November 2003 draft SPDES permit for IPEC Units 2 and 3), closed-cycle cooling, is eliminated from consideration, either in part or in whole, after application of the Department's four-step BTA analysis (as set forth in the Ruling of the Regional Director in the Entergy Indian Point SPDES permit proceeding, dated November 28, 2012) and associated SEQRA review are completed.

Background:

As an interim measure, the 2003 draft SPDES permit included a condition for Entergy to take 42 fish protective outage days annually until such time as the Department's preferred BTA alternative, closed-cycle cooling, is operational in recognition of the fact that outages of some duration will reduce the ongoing, unmitigated entrainment caused by IPEC's CWIS.

Annual outages of 42-days, or more specifically, Fish Protective Outage Days ("FPOD" or "protective outages") were historically required at IPEC (as well as at the Roseton and Bowline facilities on the Hudson River) when the Hudson River Settlement Agreement ("HRSA") took effect in 1981. Under the HRSA, the IPEC facilities were required to take 42 FPODs annually between May 15 and August 15 of each calendar year. Those required protective outages were incorporated by reference into the 1987 SPDES permit for IPEC, the permit currently in effect as a result of the State Administrative Procedure Act ("SAPA"). *See* IPEC 1987 SPDES permit No. NY0004472, Additional Requirement No. 7, at p. 11.

The FPOD options discussed in this fact sheet span a minimum of 42 days to a maximum of 92 days at one or both IPEC Units with outages being taken between May 10 and August 10 each calendar year for the proposed 20-year NRC relicensing period. In the event that a closed-cycle cooling alternative is found by the decision-maker to not be "available" at IPEC, after DEC's four-step BTA analysis and SEQRA review for closed-cycle cooling is complete, protective outages provide a readily feasible alternative to the Department's preferred option of closed-cycle cooling to reduce, and in some instances minimize, the adverse environmental impact that has been determined as a matter of law to be caused by IPEC's CWIS. *See* Interim Decision of the Assistant Commissioner, Aug. 13, 2008, at pp. 16-18, including footnotes 10, 11, and 12.

Accordingly, this fact sheet provides both an estimated efficacy and a wholly disproportionate cost analysis for the following alternatives:

1. Fish Protective Outage Days (of 42, 62, or 92 day durations) taken annually at both IPEC Units between May 10 and August 10 for the 20-year NRC license renewal period; and

2. A closed-cycle cooling system installed at Unit 2 only with Fish Protective Outage Days (of 42, 62, or 92 day durations) taken annually at IPEC Unit 3 between May 10 and August 10 for the 20-year NRC license renewal period.

Discussion:

Rationale for the Efficacy of Protective Outages

Protective outages are an effective method for reducing and, in certain instances, even minimizing the impingement mortality and entrainment of fish of all life stages. Protective outages were historically implemented at the three power plants which were parties to the HRSA and, to compliment the HRSA plant outages, the Danskammer Generating Station, another power plant located on the Hudson River, was also required to take annual protective outages as a BTA condition of its previous SPDES permit. *See* *Matter of Dynegy Northeast Generation, Inc., on behalf of Dynegy Danskammer, LLC*, Decision of the Deputy Commissioner, May 24, 2006; *see also* *Riverkeeper, Inc. v Johnson*, 52 AD3d 1072 (3d Dept. 2008), *appeal denied* 11 NY3d 716 (2009). As noted above, Indian Point's 1987 SPDES permit included the HRSA-required 42 fish protective outage days by incorporating the 1981 HRSA as a permit condition. *See* IPEC 1987 SPDES permit No. NY0004472, Additional Condition No. 7, at p. 11.

From a technical stand point, protective outages have certain advantages over a full closed-cycle cooling retrofit. Protective outages can be implemented immediately thereby providing direct reductions in the ongoing, established adverse environmental impact caused by IPEC's CWIS (*see* Interim Decision of the Assistant Commissioner, Aug. 13, 2008, at pp. 16-18, including footnotes 10, 11 and 12).

Implemented on their own, protective outages would not cause any on-site physical disturbances or construction impacts, or off-site visual, noise, or traffic impacts associated with retrofitting IPEC with a closed-cycle cooling system. A partial retrofit (*i.e.*, retrofitting only Unit 2 with closed-cycle cooling) used in conjunction with protective outages at Unit 3 would significantly reduce any short or long-term impact identified in conjunction with a full closed-cycle cooling retrofit of both IPEC Units.

Protective outages are effective for reducing entrainment due to the fact that the time of year a particular fish species will be present or spawn in the Hudson River is highly predictable. In fact, the majority of entrainment that occurs at IPEC has historically taken place between May 10 and August 10 of each year (*see* Figure 1 below). This discrete biological window was recognized by the parties to the HRSA which targeted 42 fish protective outage days at IPEC to occur annually between those dates. Figure 1 presents the combined average density and estimated baseline entrainment of six species commonly entrained at IPEC between May 1 and August 10 for the years 1984 through 1987 (*i.e.*, striped bass, bay anchovy, white perch, river herring, American shad, and Atlantic tomcod).

Though the *peak* entrainment may vary somewhat from year to year depending on a variety of factors, the relative timing of entrainment abundance, as reflected in Figure 1, is highly predictable. In fact, if Entergy were to take protective outages for the entire 92 day period from May 10 through August 10 at both Units 2 and 3 (*i.e.*, 184 unit outage days annually), it is estimated that the reduction in entrainment could potentially exceed that achievable with a closed-cycle cooling retrofit at both IPEC Units.

Figure 1 highlights two periods within the total 92-day entrainment window where peak entrainment occurs. These periods are from May 20 through June 20 (denoted as “A” in Fig. 1), and July 10 through August 10 (denoted as “B” in Fig. 1). While the HRSA allowed for the 42 fish protective outage days to be applied anywhere within the total 92-day window, what is clear from Figure 1 is that if these 42 FPODs are targeted to incorporate the two peak density windows, the effectiveness of the 42 fish protective outage days would be maximized. For instance, outages taken at IPEC during period "A" would target entrainment of striped bass, white perch, American shad and river herring (in addition to other species of lower densities). Outages taken at IPEC during period "B" would primarily target entrainment of bay anchovy (though the entrainment of other, less dense ichthyoplankton would also be reduced).

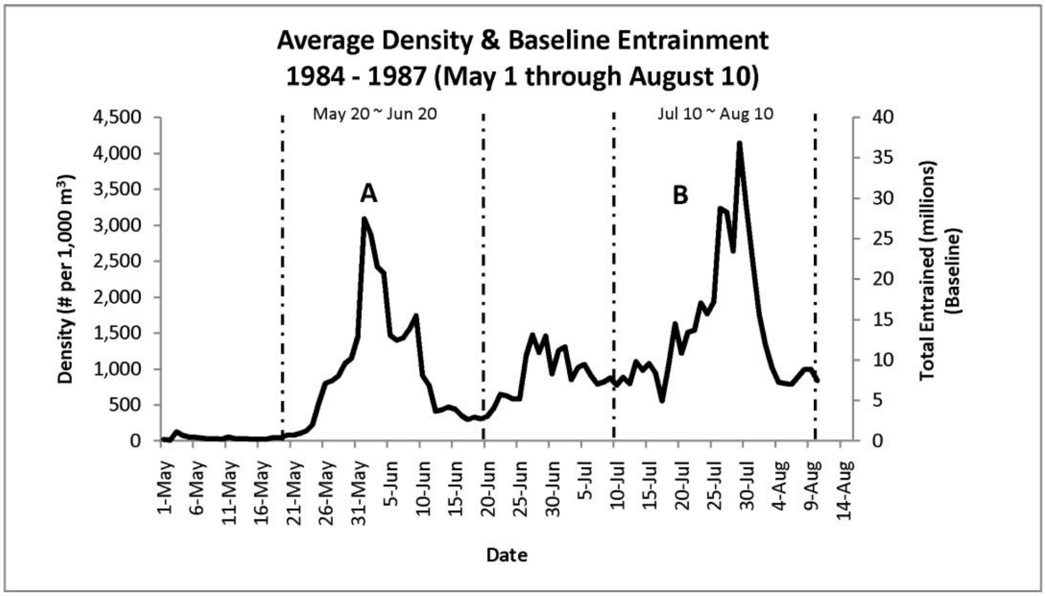

Figure 1: The combined average density (#/1,000 m^3) and estimated baseline entrainment (millions) of striped bass, bay anchovy, white perch, river herring, American shad, and Atlantic tomcod entrained at IPEC from May 1 through August 10 for the years 1984 through1987. Data for this Figure was taken from the 1984 -1987 Indian Point Generating Station Entrainment Abundance Program Annual Reports (EA 1985; NAI 1987 a and b; NAI 1988).

Historic data also demonstrates a seasonal component for impingement (*see* EA 1989, at p. 3-15). Figures 2 and 3 (below) present the average density and estimated baseline number of fish impinged at IPEC for each month from 1979 to 1990. These graphs show that impingement at IPEC is typically highest from December through March each year, accounting for nearly 57 percent of the annual impingement on average.

The seasonality of impingement at IPEC has been known for some time and was previously reported by Consolidated Edison Company of New York, previous owner of the IPEC facilities (*see* Con Ed 1982, at p. 3-7; and Con Ed 1984, at p. 3-13). The period from May through August, which corresponds to the annual period when fish protective outage days were required under the HRSA, on average accounted for only about 25 percent of the total potential annual impingement. This is why protective outages alone were insufficient to reduce impingement mortality at IPEC and why additional measures of installing modified Ristroph traveling screens and a dedicated fish return system were necessary to reduce impingement mortality at IPEC under the HRSA.

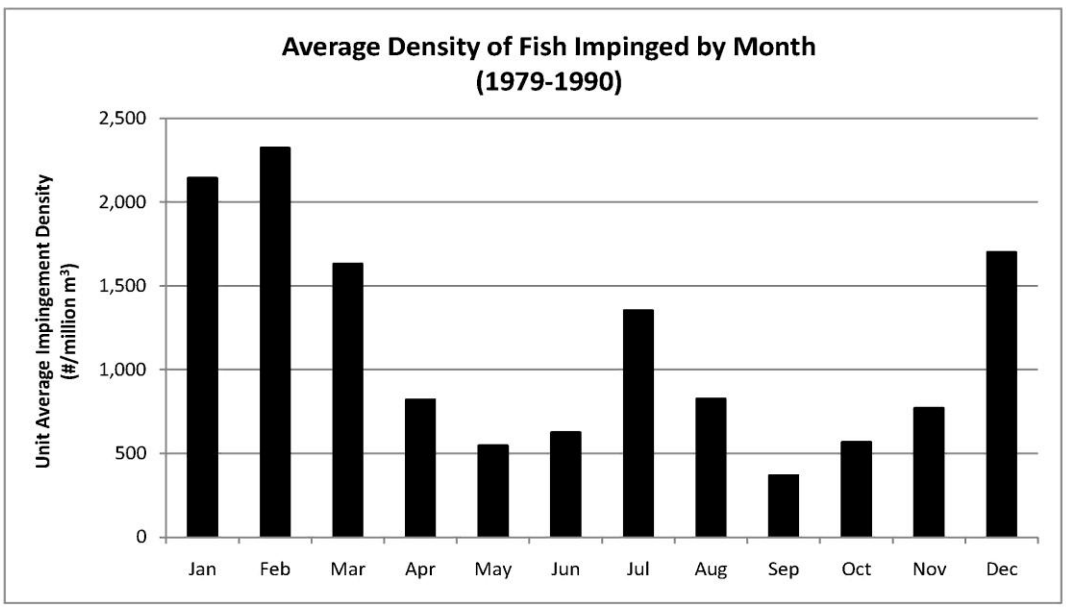

Figure 2: Annual distribution of the unit average density of fish impinged at IPEC from 1979 to 1990. Data presented were averaged from interpolations made from figures presented in the *"Hudson River Ecological Study in the Area of Indian Point"* reports covering calendar years 1979 through 1990 (*see* Literature Cited section of this fact sheet).

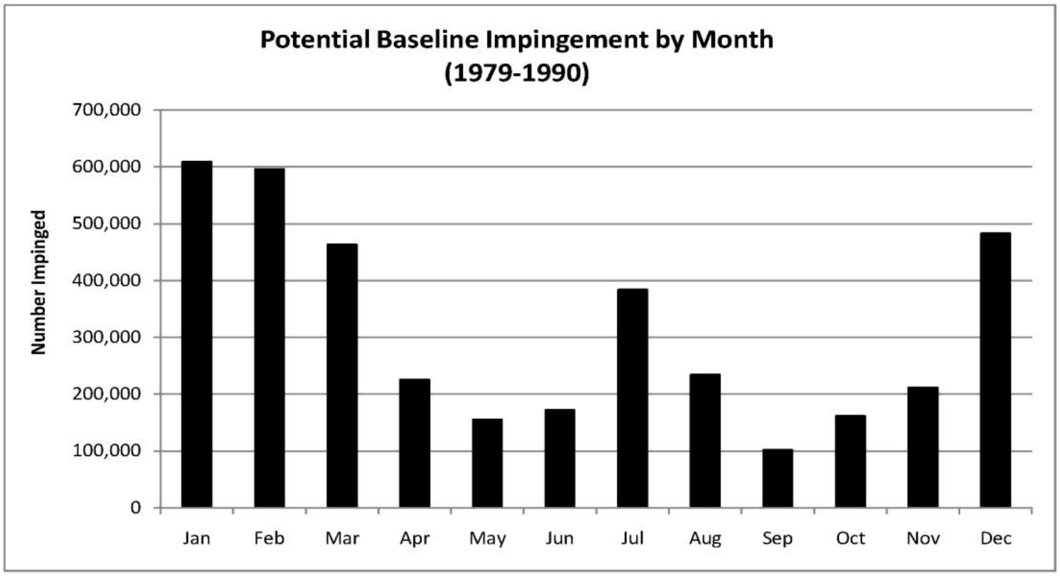

Figure 3: Annual distribution of the average baseline impingement at IPEC from 1979 through 1990. Data presented were calculated by multiplying the average impingement density for each month and each generating Unit by the maximum cooling water capacity [*i.e.,* 4,579.2 (1,000 m^3) per day per generating unit].

The Wholly Disproportionate Test

The Department does not conduct a formal "cost-benefit" analysis as part of its BTA determination that would cause the resource, in this case aquatic organisms, to be monetized. The only consideration of cost in the selection of BTA is a "wholly disproportionate" cost test that is applied during the fourth step of the Department's BTA Analysis.[1] *See* Ruling of the Regional Director, Nov. 28, 2012. The "wholly disproportionate test" has been used by the Department for several years in SPDES permit/BTA determination matters (*see* e.g., Matter of Athens, *Interim Decision of the Commissioner*, June 2, 2000; Matter of Mirant Bowline LLC, *Decision of the Commissioner*, March 19, 2002; and Matter of Dynegy Northeast Generation, Inc. *Decision of the Deputy Commissioner*, May 24, 2006). *See also* CP-52.

[1] This wholly disproportionate test is not a traditional cost-benefit analysis and such an analysis is not required by CWA §316(b) (*see Entergy Corp. v Riverkeeper, Inc., et al.,* 556 U.S. 208, 129 S.Ct. 1498 [2009]).

In the November 2012 Ruling of the Regional Director, the fourth step of the BTA analysis was defined as follows: "whether the costs of feasible technologies are wholly disproportionate to the environmental benefits to be gained from such technologies" (at p. 8). The November 2012 Ruling went on to state that "CP-52 and administrative precedent shall be used as guidance in the application of the fourth step." ***Id.*** at 8. CP-52 further defined the wholly disproportionate test as "neither a traditional cost-benefit analysis nor an economic analysis but simply a comparison of the proportional reduction in impact (benefit) as compared to the proportional reduction in revenue (cost) of installing and operating BTA technology to mitigate adverse environmental impact. This comparison does not monetize the resource and gives presumptive weight to the value of the environmental benefits to be gained" (*see* CP-52, at p. 4).

The proportional environmental benefits to be gained are evidenced by the expected efficacies of the feasible technologies or operational measures in reducing entrainment and impingement mortality. The efficacies of technologies and operational measures can either be directly estimated from site specific entrainment, impingement, and operational data, or these efficacies can be based on the results of published studies.

For purposes of this fact sheet, some efficacies were taken from previously provided reports and data (*i.e.*, Enercon 2010) with some efficacies calculated based on past entrainment and current operational data from IPEC. Consequently, for purposes of this fact sheet, the following estimates of the aquatic organisms annually at risk at IPEC Units 2 and 3 were used: 1.224 billion fish entrained; and 669,465 fish impinged. *See* Enercon 2010 Alternatives Report, Attachment 6, Table 3, at p. 20 (Entergy Ex. 8). These estimates represent the most current DEC-accepted calculation baseline for purposes of determining BTA under 6 NYCRR §704.5.

To estimate the reduction in entrainment and impingement that would result from protective outages, historic entrainment data reported in the annual entrainment abundance reports for sampling years 1984 through 1987, and historic impingement data reported in the annual Hudson River ecology reports from sample years 1979 through 1990 were analyzed to determine relative abundances and seasonal trends in impingement and entrainment. *See* Literature Cited section of this fact sheet.

Analysis and Results:

Gross Annual Revenue and Potential Costs of Taking Protective Outages

The data used for estimating the gross annual revenue for Indian Point were taken from the NYISO 2009 through 2013 Load and Capacity Reports (*i.e.* "Gold Book")[2] [*see* Table 1 below], and from the NYISO Monthly Reports (July 2012 through June 2013)[3] [*see* Table 2 below]. Tables 1 and 2 (below) present the electric generating data and monthly average day ahead market rate for wholesale electricity used in the calculation of costs and revenues in this fact sheet.

Table 1: Average generating capacity of IPEC Units 2 and 3 from 2008 to 2012.

Year	Generating Capacity (MWHr)
2008	17,381,849
2009	16,542,300
2010	16,320,600
2011	17,016,900
2012	16,937,900
5-year Average	*16,839,910*

2 http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

3 http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp

Table 2: The average monthly day ahead market price for wholesale electricity from July 2012 through June 2013 for Zone H (Millwood).[4]

Year	Price per MWHr
July 2012	$48.07
August 2012	$39.86
September 2012	$35.84
October 2012	$36.61
November 2012	$49.45
December 2012	$44.92
January 2013	$74.70
February 2013	$85.73
March 2013	$48.19
April 2013	$42.84
May 2013	$43.29
June 2013	$41.68
12-month Average	*$49.27*

Estimated Efficacy and Costs of Protective Outages

Table 3 (below) presents the proportional environmental benefits and proportional increase in costs of six different feasible BTA options at IPEC that include protective outages (*i.e*, Options *A – F*) as well as a previously considered alternative of a 32-week forced outage.

Options *A*, *B*, and *C* in Table 3 present the costs and reductions in adverse environmental impact associated with taking 42, 62, and 92 days, respectively, of fish protective outages at both IPEC generating Units annually during the period from May 10 through August 10.

Options *D*, *E*, and *F* in Table 3 present the costs and reductions in adverse environmental impacts associated with retrofitting only IPEC Unit 2 with closed-cycle cooling and taking either 42, 62, or 92 days, respectively, of fish protective outages annually at Unit 3 during the period

[4] The one-year time period reflected in Table 2 is for illustration purposes in this fact sheet only and was previously prepared by DEC staff in November 2013 (and has not been updated). DEC staff recognizes that other, current or additional months/years of average monthly day-ahead market prices for wholesale electricity may be utilized to analyze this topic in the future “when hearings on permanent forced outages take place.” *See* Memorandum Ruling, p. 8, at ¶2.

from May 10 through August 10. For the partial retrofit options (*i.e.*, *D, E, & F*), Unit 2 was selected for closed-cycle cooling since this would eliminate the need (and, therefore, the estimated associated costs of $14.8 million) of moving the Algonquin natural gas pipeline in conjunction with a closed-cycle cooling retrofit at Unit 3 (*see* June 2013 Tetra Tech Report, at p. 26).

Table 3: Proportional reductions in entrainment (E), impingement mortality (IM), and costs estimated for six mitigative options to reduce adverse environmental impacts caused by IPEC Units 2 and 3 CWIS. Annual costs include all construction costs amortized over the 20-year NRC relicensing period, any outage costs, and any necessary annual maintenance cost. Note that the costs and benefits estimated for options *A*, *B*, and *C* presume that Fish Protective Outage Days (FPODs) are taken at *both* operating Units (*i.e.,* Option *A* would require a total of 84 unit outage days).

Mitigative Option:	***32-Week Outage***[5]	***A*** 42 FPOD Units 2&3	***B*** 62 FPOD Units 2&3	***C*** 92 FPOD Units 2&3	***D*** 42 FPOD Unit 3 Closed-cycle Unit 2	***E*** 62 FPOD Unit 3 Closed-cycle Unit 2	***F*** 92 FPOD Unit 3 Closed-cycle Unit 2
Annual cost (million)	$475.1	$61.4	$106.8	$175.0	$70.3	$93.0	$127.1
20 Year Cost (million)	$9,502	$1,227.5	$2,136.8	$3,500.7	$1,388.8	$1,843.1	$2,525.0
Annual Revenue (million)	$829.7	$829.7	$829.7	$829.7	$814.1	$814.1	$814.1
Proportional E Benefit	~100 %	66.3 %	76.2 %	99.5 %	81.1 %	86.1 %	97.7 %
Proportional IM Benefit	92.2 %	81.1 %	82.4 %	84.9 %	90.0 %	90.6 %	91.9 %
Proportional Cost	57.3 %	7.4 %	12.9 %	21.1 %	8.6 %	11.4 %	15.6 %

[5] The 32-week outage column in this Table represents a 32-week outage period that was previously considered by DEC in the fact sheet that accompanied the 2003 draft SPDES permit. The protective outages in columns A – F are not synonymous with the 32-week outage considered or discussed in the fact sheet that accompanied the 2003 draft SPDES permit. If a 32-week outage was taken from February 15th through September 15th at both Units annually, it would cost more than $9,500,000,000 over the 20-year relicensing period for IPEC. Using current revenue figures, DEC staff estimated that this would amount to more than 57 % of IPEC's gross annual revenue. While the Department also found that an annual 32-week outage would reduce fish mortality at levels commensurate with closed-cycle cooling, DEC staff declined this option as BTA because the added annual costs were determined to be wholly disproportionate to the added benefits gained over DEC staff's preferred BTA alternative (*i.e.*, a closed-cycle cooling retrofit of both IPEC Units 2 and 3).

The most protective alternative for minimizing entrainment presented in Table 3 would be for IPEC to take 92 day FPODs at both Units from May 10 through August 10 each year (*see* Option *C*) which is estimated to produce a proportional entrainment benefit exceeding 99 percent. This option, along with the presumed efficacy of the existing modified Ristroph traveling screens at IPEC, is estimated to also reduce impingement mortality by nearly 85 percent. However, taking 92 fish protective outage days at both IPEC Units would also be the most costly of the protective outage options analyzed and would raise annual costs (by reducing revenue) at the facilities by 21.1 percent.

Two options (options *E* and *F*) are estimated to provide reductions in impact commensurate with a full closed-cycle cooling retrofit. Option *F* (92 FPODs and closed-cycle cooling at Unit 2) is estimated to reduce entrainment by nearly 98 percent and impingement mortality by nearly 92 percent. This alternative would cost 5.5 percent less on an annual basis than taking 92 FPODs at both units. Option *E* reduces costs further and is still estimated to reduce impingement and entrainment to levels commensurate with a closed-cycle cooling system.

The least expensive fish protective outage alternative presented in this fact sheet is for IPEC to take 42 FPODs annually at both Units (Option *A*). This alternative would result in annual proportional increases in costs to Entergy of 7.4 percent. However, this alternative is estimated to only reduce entrainment by approximately 66 percent, thereby not meeting the efficacy goal required by the 2008 Interim Decision or the entrainment performance goal in Department Policy CP-52. Impingement mortality reductions resulting from Option *A* would essentially remain unchanged from current mortality levels.

<u>Conclusion</u>:

As noted, a number of the protective outage options presented in this fact sheet would likely be less protective than the efficacy and performance goals identified in the Aug. 13, 2008 Interim Decision and Department Policy CP-52 for entrainment reductions. In fact, several protective outage options fall short of the reductions in impingement mortality achievable with a full closed-cycle retrofit.

However, in the event that a closed-cycle cooling retrofit of both IPEC Units 2 and 3 is determined to be unavailable following the application of the four-part BTA analysis and associated SEQRA review, annual protective outages offer an immediately viable and less complex option to significantly reduce the adverse environmental impact caused by the existing CWIS at the facilities. This is especially true if annual outages are used in conjunction with a closed-cycle cooling retrofit of one of the generating IPEC Units in order to meet the BTA requirements of 6 NYCRR §704.5.

Dated: May 9, 2014
Albany, New York

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[6] References in parentheses (delineated as "Ex. __") refer to Exhibits identified and received in the evidentiary record by the ALJs for the administrative proceedings on IPEC's SPDES permit renewal application and CWA §401 water quality certificate denial as of May 7, 2014.

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