

STATE OF NEW YORK
DEPARTMENT OF ENVIRONMENTAL CONSERVATION
625 BROADWAY
ALBANY, NEW YORK 12233-1010

In the Matter

- of -

a Renewal and Modification of a State
Pollutant Discharge Elimination System
("SPDES") Permit Pursuant to Article 17 of
the Environmental Conservation Law and Title
6 of the Official Compilation of Codes, Rules
and Regulations of the State of New York
Parts 704 and 750
et seq.

- by -

**DYNEGY NORTHEAST GENERATION, INC.,
ON BEHALF OF DYNEGY DANSKAMMER, LLC
(DANSKAMMER GENERATING STATION),**

Permittee.

DEC No.: 3-3346-00011/00002
SPDES No.: NY-0006262

DECISION OF THE DEPUTY COMMISSIONER

May 24, 2006

DECISION OF THE DEPUTY COMMISSIONER¹

This proceeding involves the renewal and modification of the State Pollutant Discharge Elimination System ("SPDES") permit held by Dynegy Northeast Generation, Inc. on behalf of Dynegy Danskammer, LLC ("Dynegy") for the Danskammer Generating Station ("facility"). The facility, which generates electricity, is located on the western shore of the Hudson River at 992-994 River Road, in the Town of Newburgh, Orange County, New York ("site").

Administrative Law Judge ("ALJ") Daniel P. O'Connell, to whom this matter was assigned, has prepared the attached hearing report, in which he finds that:

- the proposed closed-cycle cooling system retrofit configurations will not fit on the site;
- with respect to the Danskammer Alternative Technology Evaluation Model ("DATEM"), the baseline should be calculated using full-flow, credit should be given for entrainment survival, and the temperature data and assumptions used are accurate;
- the conditions in the revised draft SPDES permit (Adjudicatory Hearing ["AH"] Exhibit ["Exh"] 6) are the best

¹ By memorandum dated February 8, 2005, then Acting Commissioner Denise M. Sheehan delegated decision making authority in this proceeding to Deputy Commissioner Carl Johnson.

technology available for minimizing adverse environmental impacts; and

- the matter should be remanded to Department staff with instructions to issue the revised draft SPDES permit to Dynegy.

The ALJ's hearing report thoroughly and cogently analyzes the complex issues raised in this proceeding. Based on my review of the record, I hereby adopt the hearing report as my decision in this matter, subject to the following comments.

BACKGROUND

Dynegy acquired the facility from Central Hudson Gas & Electric Corp. ("Central Hudson") in January 2001. This existing facility, which consists of four fossil-fueled steam turbines (referred to as units 1, 2, 3 and 4), has a total net generating capacity of 491 megawatts. The facility pumps water from the Hudson River through an intake canal for cooling purposes. The water passes through the facility once before it is discharged back into the river through three discharge pipes ("once-through cooling system").

Vertical traveling screens are located in front of the cooling water pumps in the intake canal to prevent debris from

entering the pump chambers and condensers. Although the screens block the passage of larger aquatic organisms, smaller organisms pass through the screens and the cooling system and are subsequently returned to the river through the discharge pipes.

To reduce the entrainment and impingement of fish and other aquatic biota that occurs² when water is withdrawn from the Hudson River, staff of the Department of Environmental Conservation ("Department") has proposed, in the revised draft SPDES permit, that Dynegy implement certain technologies. These technologies include the use and evaluation of a high-frequency, high-energy sonic fish deterrent device at the opening of the facility's intake canal and the implementation of a flow reduction program (see Hearing Report, at 23-24; AH Exh 6).

In my interim decision dated May 13, 2005 ("Interim Decision"), I determined that the following two issues were to be adjudicated:

² "Entrainment" is the process by which smaller organisms including larval fish and fish eggs are carried along with the intake water through any intended exclusion technology (such as screens) into the cooling system where they may be damaged or killed (see Matter of Athens Generating Co., LLP, Interim Decision of the Commissioner, June 2, 2000, at 12-13). "Impingement" occurs when larger organisms, such as fish, are trapped against intended exclusion technology (such as screens) by the force of the intake water flows, which may suffocate or injure the organisms (see id. at 13; see also Hearing Report, at 23).

- whether a closed-cycle cooling system to reduce impingement and entrainment could be located on the site and, if so, whether the facility must be retrofitted with such a system to satisfy the "best technology available" requirement contained in section 316(b) of the federal Clean Water Act and section 704.5 of title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York ("6 NYCRR").³ With respect to the adjudication of this issue, the use of properties other than the site, or the use of piers or barges in the Hudson River were not to be considered; and

- whether certain assumptions in DATEM, the model to be used to evaluate the facility's flow reduction and outage

³ Operators of facilities in New York State with cooling water intake structures that, as point sources, are subject to SPDES permits are required to comply with section 316(b) of the federal Clean Water Act ("CWA") and 6 NYCRR 704.5. Codified at section 1326(b) of title 33 of the United States Code ("USC"), CWA § 316(b) reads as follows: "Any standard established pursuant to [33 USC § 1311, "Effluent limitations"] or [33 USC § 1316, "National standards of performance"] and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact" (emphasis added).

Section 704.5 of 6 NYCRR states: "[t]he location, design, construction and capacity of cooling water intake structures, in connection with point source thermal discharges, shall reflect the best technology available for minimizing adverse environmental impact" (emphasis added) (see generally Matter of Mirant Bowline, LLC, Decision of the Commissioner, March 19, 2002; Matter of Athens Generating Co., LP, Interim Decision of the Commissioner, June 2, 2000).

program, were reliable (Interim Decision, at 1).⁴

Parties to the adjudicatory hearing included Riverkeeper, Inc., Scenic Hudson, Inc., and Natural Resources Defense Council, Inc. (collectively, "petitioners"), Department staff, and Dynegy. Following issuance of the Interim Decision, and after discovery, a site visit and the preparation and submission of prefiled direct and rebuttal testimony, the adjudicatory hearing commenced on November 16, 2005.⁵

Eighteen witnesses testified during sixteen days of hearings that were held during the months of November and December 2005. The adjudicatory hearing transcript consists of approximately 3,600 pages, and nearly 200 exhibits were received into evidence.

⁴ The procedural history of this matter is set forth in the Hearing Report, at 1-6 (see also Interim Decision, at 2-12).

⁵ On the morning of the first day of the adjudicatory hearing, proposed intervenor Central Hudson filed a late petition for full party status. Following the ALJ's denial of Central Hudson's request for party status, it filed an expedited appeal from the ALJ's ruling. Central Hudson's appeal is addressed infra, at 21-26.

CLOSED-CYCLE COOLING SYSTEM

Petitioners, in their petition for party status, proposed that the facility be retrofitted with a closed-cycle cooling system. Installation of a closed-cycle cooling system would reduce the amount of water that the facility withdraws from the Hudson River. This, in turn, would reduce the number of aquatic organisms that could be entrained and impinged by the facility's cooling system.

In the adjudicatory hearing, petitioners proposed eight potential design configurations to fully retrofit the facility with a closed-cycle cooling system ("full retrofits" or "full retrofit configurations"), and four potential design configurations to retrofit electric generating units 3 and 4 ("partial retrofits" or "partial retrofit configurations"), for a total of twelve configurations (see AH Exh 19).⁶

⁶ Petitioners, in their offer of proof at the issues conference, presented eight potential closed-cycle cooling configurations for the site (Petition for Party Status dated October 14, 2003 ["Petition"], at 22 [see §§ a, b, c & d] & Exhibit E to the Petition). The Interim Decision directed petitioners to submit, prior to the adjudicatory hearing, their configurations for the full and partial retrofits. Petitioners were limited to eight configurations as proposed in their petition for party status and, in addition, were allowed, subject to the ALJ's discretion as to number, to propose partial retrofit configurations for electric generating units 3 and 4 (see Interim Decision, at 17).

By letter dated June 10, 2005 from petitioners to ALJ O'Connell ("June 2005 Letter"), petitioners initially produced a

The threshold question is whether sufficient space exists on the site to accommodate a closed-cycle cooling system (see Interim Decision, at 14). The ALJ, in his hearing report, has reviewed the full and partial retrofit configurations that petitioners proposed, including but not limited to their structural components, design, and physical feasibility with respect to this site (see Hearing Report, at 25-50).

Petitioners identified seven potential areas on the site where closed-cycle cooling towers could be located (see AH

list of more than 100 configuration options. Petitioners then replaced that list with a list of approximately seventy configuration options in an August 4, 2005 letter to the ALJ ("August 2005 Letter").

In a conference call on August 11, 2005, Department staff and Dynegy objected to petitioners' submissions and contended that petitioners had failed to comply with the directives in the Interim Decision. They argued that petitioners disregarded the limitations on the number of potential configurations that could be offered and, in addition, that the configurations petitioners proposed lacked sufficient specificity to allow for any meaningful evaluation. The ALJ determined that, for purposes of the adjudicatory hearing and in accordance with the Interim Decision, petitioners would be limited to eight potential full retrofits and four potential partial retrofits, for a total of twelve (see Memorandum regarding Conference Call held on August 11, 2005 and Scheduling Order, dated August 12, 2005). No appeals were taken from the ALJ's ruling nor were any objections to that ruling raised in the closing briefs.

Dynegy's and Department staff's objections were well-founded. Indeed, petitioners' lack of specificity with respect to the configurations they submitted in the June and August 2005 Letters is perplexing in light of the details that petitioners had previously provided in their offer of proof at the issues conference.

Exh 19 [petitioners exhibit]; see also AH Exh 114 [Dynergy exhibit]). The ALJ described each of these seven areas (see Hearing Report, at 28-31),⁷ and identified the areas on which the components of each configuration would be located (see id. at 32-42; see also Appendix D to the Hearing Report [Chart Concerning Proposed Cooling Tower Configurations]).

The ALJ found that one or more components of each of the eight full and four partial retrofit configurations proposed by petitioners would not fit on the site and, accordingly, that none of the configurations were available for purposes of the Department's best technology available analysis.

The record clearly demonstrates that petitioners failed to take into account physical site constraints and engineering limitations with respect to their proposed configurations. For

⁷ Dynergy, in its submission, described the proposed configurations in terms of the site's western, northern and southern locations, while petitioners described the configurations in terms of the site's western, northern, southern and "east of the powerhouse" locations (see, e.g., Post-Hearing Brief of Dynergy Northeast Generation, Inc., February 13, 2006, at 22-38; Closing Brief of Petitioners, February 13, 2006, at 8-9). The "western location" referenced by Dynergy and petitioners corresponds to the area that the ALJ designated as "area 7." The "southern location" that Dynergy references generally corresponds to ALJ-designated areas "5" and "6." Petitioners' "southern location" generally corresponds to ALJ-designated area "6" and their "east of the powerhouse" location, to area "5." Dynergy's and petitioners' "northern section" corresponds to the areas that the ALJ designated as "1," "2," "3," and "4."

example, the record reveals that area 2, on which petitioners proposed to place a cooling tower for purposes of full retrofit configurations 1, 2, 5 and 6 and partial retrofit configuration 1, is not wide enough to accommodate that tower. Some portion of each of these configurations, as proposed by petitioners, would have to be placed within the bed or bank of the Hudson River, and such placement is not feasible at this site (see, e.g., AH Transcript ["Tr."], at 2124, 3364-3366 [Department staff testimony that an article 15 permit would be required, and no such permit would be issued for the placement of fill in the Hudson River to construct cooling towers due to the permanent loss of aquatic habitat]). Accordingly, these proposed configurations are not available.

Furthermore, petitioners failed to evaluate adequately the impacts of their proposed configurations on the facility's operating conditions. The record demonstrates that petitioners' proposed closed-cycle cooling tower for unit 4 would be significantly undersized and would routinely contribute to excessively high turbine backpressures that would not adequately satisfy the original design standards for unit 4's steam-driven turbine. Under such operating conditions, the unit 4 turbine would be damaged over time. Accordingly, a cooling tower larger than the one petitioners proposed would be needed for unit 4.

However, both area 3 (where petitioners proposed to locate the cooling tower for unit 4 for full retrofit configurations 1 and 6, and partial retrofit configuration 1) and area 6 (where petitioners proposed to locate the cooling tower for unit 4 for full retrofit configurations 4, 5, 7 and 8 and partial retrofit configurations 2, 3, and 4) are too small to accommodate a larger-sized cooling tower. Accordingly, those ten proposed configurations are not available.⁸

⁸ For the remaining two configurations (full retrofit configurations 2 and 3), petitioners proposed that the cooling tower for unit 4 be placed on area 7 which might be able to accommodate a larger sized tower if other physical and operational constraints identified by Dynegy and Department staff are not considered. However, full retrofit configuration 2 is excluded because it would also use area 2 for a cooling tower which is not wide enough to accommodate the tower (see supra, at 8-9). Full retrofit configuration 3 is not available because it would also use area 6 which, because of the need to accommodate air pollution control equipment at that location, would have insufficient space for a cooling tower (see infra, at 11-13).

Based on my review of the record, I also find that petitioners' proposal to retrofit unit 3 with air cooled condensers would routinely contribute to excessively high turbine backpressures that would seriously compromise original design standards for that steam-driven turbine (see, e.g., AH Tr., at 1746, 1752-1753, & [December 19] 3008). Furthermore, the construction required for this retrofit raises serious structural integrity concerns that petitioners have not adequately addressed (see, e.g., AH Tr., at 1416-1420; Post-Hearing Brief of Dynegy Northeast Generation, Inc., at 50-51). For the reasons stated by the ALJ in the hearing report (see Hearing Report, at 49-50), I assign significant weight to the expert testimony provided by Dynegy's witnesses as a basis for this finding. Accordingly, the configurations that would include the installation of air cooled condensers to meet the cooling needs of unit 3 (full retrofit configurations 7 and 8, and partial retrofit configuration 4) are not available.

In addition, because petitioners significantly underestimated the air emissions that would result from installation of their proposed configurations, petitioners failed to account for the attendant environmental impacts. Petitioners' calculations, once corrected at the hearing, revealed that, if the proposed configurations were installed, sulfur dioxide emissions would increase. As a result of the increase in emissions, the facility would be subject to additional requirements under the federal Clean Air Act such as the regulations governing the prevention of significant deterioration of air quality. This would require the facility to install additional air pollution control equipment, such as a flue gas desulfurization ("FGD") system (see Hearing Report, at 50-55).

During the hearing, petitioners acknowledged that retrofitting the facility's cooling system and the resultant increase in sulfur dioxide emissions would require Dynegy to install such additional equipment and that an FGD system is a recognized pollution control technology for addressing these emissions (see AH Tr., at 1242, 1244; see also AH Tr. [December 19], at 3010 [Dynegy expert identifying FGD system as technology most commonly considered to be best available control technology for sulfur dioxide emissions for facilities such as the

Danskammer Generating Station])).⁹

At the hearing, Dynegy reviewed the physical impacts of installing an FGD system. Such installation would substantially reduce the space available in the area that the ALJ has identified as area 6 and would preclude the placement of a closed-cycle cooling tower at that location (see, e.g., AH Exh 114 [which depicts the space required for the FGD system on area 6]), as is proposed in nine of petitioners' configurations. Petitioners proposed an alternative system (the Chiyoda FGD system), but failed to demonstrate that their alternative was properly sized or designed for this facility. No other air pollution control alternatives were presented for consideration by petitioners.

Based on the record of this proceeding, I concur with the ALJ's finding that, as a result of the need to install air pollution control equipment on area 6 and the space that such equipment would require, the cooling tower proposed by petitioners for area 6 would not fit. Accordingly, the nine

⁹ During the hearing, the use of low sulfur fuel was considered as an alternative to the installation of additional air pollution control equipment. The record demonstrates that the use of low sulfur fuel would not control sulfur dioxide emissions sufficiently to avoid the need to install such equipment (see, e.g., AH Tr. [December 19], at 3013-3014).

proposed configurations that include a cooling tower on area 6 (six of the full configurations [3, 4, 5, 6, 7 and 8], and three of the partial configurations [2, 3, and 4]), are unavailable.

In summary, petitioners' proposed configurations are not available for the following reasons:

| CONFIGURATION | REASONS FOR UNAVAILABILITY |
|--|---|
| Configuration 1 (Full Retrofit) | <ul style="list-style-type: none"> • area 2 is too small to accommodate cooling tower. • because cooling tower in area 3 for unit 4 is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space exists in area 3 to accommodate a larger cooling tower for unit 4. |
| Configuration 2 (Full Retrofit) | <ul style="list-style-type: none"> • area 2 is too small to accommodate cooling tower. |
| Configuration 3 (Full Retrofit) | <ul style="list-style-type: none"> • cooling tower cannot be located in area 6 due to need to install air pollution control equipment. |
| Configuration 4 (Full Retrofit) | <ul style="list-style-type: none"> • because cooling tower in area 6 for unit 4 is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space in area 6 exists to accommodate larger cooling tower. • cooling tower cannot be located in area 6 due to need to install air pollution control equipment. |
| Configuration 5 (Full Retrofit) | <ul style="list-style-type: none"> • area 2 is too small to accommodate cooling tower. • because cooling tower for unit 4 in area 6 is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space exists in area 6 to accommodate larger cooling tower. • cooling tower cannot be located in area 6 due to need to install air pollution control equipment. |
| Configuration 6 (Full Retrofit) | <ul style="list-style-type: none"> • area 2 is too small to accommodate cooling tower. • because unit 4 cooling tower in area 3 is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space exists in area 3 to accommodate larger cooling tower. • cooling tower cannot be located in area 6 due to need to install air pollution control equipment. |
| Configurations 7 and 8 (Full Retrofits) | <ul style="list-style-type: none"> • because cooling tower for unit 4 in area 6 is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space exists in area 6 to accommodate larger cooling tower. • cooling tower cannot be located in area 6 due to need to install air pollution control equipment. • retrofit of unit 3 with air cooled condensers would contribute to unacceptably high turbine backpressures. |

| | |
|---|---|
| Configuration 1 (Partial Retrofit) | <ul style="list-style-type: none"> • area 2 is too small to accommodate cooling tower. • because unit 4 cooling tower (area 3) is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space exists in area 3 to accommodate larger cooling tower. |
| Configurations 2 and 3 (Partial Retrofits) | <ul style="list-style-type: none"> • because unit 4 cooling tower in area 6 is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space exists in area 6 to accommodate larger cooling tower. • cooling tower cannot be located in area 6 due to need to install air pollution control equipment. |
| Configuration 4 (Partial Retrofit) | <ul style="list-style-type: none"> • because unit 4 cooling tower in area 6 is significantly undersized, it would contribute to unacceptably high turbine backpressures, and insufficient space exists in area 6 to accommodate larger cooling tower. • cooling tower cannot be located in area 6 due to need to install air pollution control equipment. • retrofit of unit 3 with air cooled condensers would contribute to unacceptably high turbine backpressures. |

Even assuming that petitioners had been able to establish that sufficient space existed for their proposed closed-cycle cooling system configurations, I find that their failure (a) to account for other physical site constraints, including but not limited to construction-related impediments, and (b) to demonstrate that such configurations could be effectively integrated into the facility's operations without detrimental effect, would make their proposed configurations unavailable. Department staff and Dynegy presented credible evidence that, in addition to the spatial constraints, other physical features posed serious, if not insurmountable, obstacles to the construction of a closed-cycle cooling system at the facility. Department staff and Dynegy noted such obstacles as the location and shallow depth of underground electric cables to the north and south of the powerhouse (see, e.g., AH Tr., at

1350, 1396-1397), the depth of the on-site coal shed,¹⁰ and the difficulties inherent in tunneling under railroad tracks in the vicinity of area 7 (see, e.g., AH Tr., at 1358-1361).

Operational difficulties, such as the inability to withdraw service water from a closed-cycle cooling system and the use of film fill, were identified (see, e.g., AH Tr. [December 19], at 2995-2996, 3001-3006, & 3051-3053).¹¹ Record evidence also established that some portions of area 2 are located on land consisting of fill that was placed on the site some forty to fifty years ago. Petitioners failed to demonstrate that the fill-created areas would be capable of supporting the proposed cooling towers (see, e.g., AH Tr., at 1414-1415, 1838-1839).

Evidence offered by Department staff and Dynegey demonstrated that a number of these constraints taken together

¹⁰ At the hearing, petitioners' witness acknowledged construction difficulties that would be associated with the depth of the coal shed's foundation and presence of underlying conveyers (see AH Tr., at 618-619; cf. AH Tr., at 1359).

¹¹ Department staff underscored numerous constraints that would preclude locating the closed-cycle cooling system at the facility in their closing brief (see Department Staff Closing Brief, February 10, 2006, at 6-10 [referencing the extensive record evidence showing that the proposed configurations failed to take into account the facility's original design criteria and diverse site constraints]).

would preclude various configurations even though individually they might not pose a hindrance to construction of a closed-cycle cooling system at the site.

Based on my review of the record, I concur with the ALJ's findings that none of the full or partial configurations would fit on the site, nor have they be shown to be feasible for the purposes intended. Petitioners have failed to account for fundamental physical site constraints, and the facility's operational and design requirements, in their proposed configurations.

DANSKAMMER ALTERNATIVE TECHNOLOGY EVALUATION MODEL ("DATEM")

DATEM is a computer model that Dynegy would use to quantitatively assess various technologies and operating strategies for complying with the revised draft SPDES permit conditions, and to track the performance of the implemented technologies and operating strategies (see AH Tr., at 2747). DATEM operates on the principle that entrainment and impingement mortality can be reliably estimated by using the following data: (1) the volume of water withdrawn for cooling; (2) the density of organisms present in the vicinity of the intake structure; and (3) the fractional mortality of organisms involved with the intake (see id. at 2747-2748).

With respect to DATEM, the Interim Decision identified three sub-issues for adjudication:

- whether the use of full pumping capacity to calculate the baseline ("full-flow baseline"), even though the facility does not operate near capacity, is an accurate assumption;

- whether the assumption with respect to entrained organisms' survival when estimating actual mortality, which is different from the assumption used for baseline mortality, is accurate; and

- whether the temperature data and assumptions used in DATEM are accurate (see Interim Decision, at 18-21).¹²

The ALJ reviewed the record with respect to each of the DATEM sub-issues in detail and found that the full-flow baseline should be used to determine the facility's compliance with entrainment and impingement performance standards set forth in the revised draft SPDES permit (AH Exh 6). The ALJ also found that the manner in which DATEM credits entrainment survival is appropriate, and that the temperature data and assumptions used in DATEM are accurate. Based upon my review of the record, I concur with the ALJ's evaluation of these sub-issues and his

¹² In this hearing, petitioners acknowledged the reliability of DATEM (see AH Tr., at 2530 ["DATEM is a well constructed spreadsheet which is perfectly reliable for making the calculations it makes. It simply uses a full baseline to do it"]; see also AH Tr., at 2542).

findings.

At the adjudicatory hearing, the testimony of Department staff was persuasive in explaining the rationale for selecting the full-flow baseline (see, e.g., AH Tr., at 2106-2112, 2140-2141). Nothing in the record suggests that the use of the full-flow baseline would affect or bias Dynegy's ability to meet performance standards set forth in the revised draft SPDES permit. Department staff testified that two alternatives (use of a standard capacity factor and use of past performance) to the full-flow baseline were considered. Department staff's articulation of the rationale for the selection of the full-flow baseline for purposes of DATEM is convincing and well-supported by the record.

Department staff also fully explained the reasons for providing a credit to the facility for entrainment survival. In particular, Department staff referenced site-specific entrainment studies that had been conducted at the facility, with the Department's involvement and oversight (see, e.g., AH Tr., at 2112-2113, 2141-2144, 3319-3320).

Dynegy effectively addressed the rationale for the temperature data and assumptions used in DATEM, and the

representative nature of the measurements employed (see Hearing Report, at 76-78). Petitioners failed to provide any support for their assertions. Indeed, with respect to temperature data, petitioners in their petition for party status alleged that the temperature input data for DATEM failed to account for recent increases in temperature of the Hudson River and indicated that they would present data to show that the water temperature data entered into DATEM was about 5° Fahrenheit too low. At the hearing, Dynegy presented its rationale for the use of daily temperature measurements collected at the City of Poughkeepsie water intakes (see also AH Tr., at 2113-2114 [Department staff rejection of petitioners' argument]). Petitioners, however, failed to present anything at the adjudicatory hearing in support of their initial offer of proof with respect to this question.

BEST TECHNOLOGY AVAILABLE

In the Interim Decision, I identified the requirements set forth at 6 NYCRR 704.5 and State administrative decisional precedent as the appropriate legal standard in determining whether the facility, as conditioned by the revised draft SPDES permit (AH Exh 6), will implement the best technology available ("BTA") for minimizing adverse environmental impacts (see Interim Decision, at 31).

BTA determinations in New York are conducted on a site-specific basis (see, e.g., Matter of Mirant Bowline, LLC, Decision of the Commissioner, March 19, 2002, at 11; Matter of Athens Generating Co., LP, Interim Decision of the Commissioner, June 2, 2000, at 9 [BTA determinations made by employing a "point source by point source" application]). BTA for a particular facility is determined by the following four step analysis:

(1) whether the facility's cooling water intake structure may result in adverse environmental impact;

(2) if so, whether the location, design, construction and capacity of the cooling water intake structure reflects BTA for minimizing adverse environmental impact;

(3) whether practicable alternate technologies are available to minimize the adverse environmental effects; and

(4) whether the costs of practicable technologies are wholly disproportionate to the environmental benefits conferred by such measures (see Matter of Athens Generating Co., LP, Interim Decision of the Commissioner, June 2, 2000, at 4).

The ALJ concludes that the seasonal sonic deterrent equipment, and the flow reduction and outage program presently required in the revised draft SPDES permit, meet the BTA standard. Because none of the twelve closed-cycle cooling system retrofit configurations proposed by petitioners fit on the site,

it is not necessary to consider whether the proposed costs of petitioners' closed-cycle cooling system configurations are wholly disproportionate to the environmental benefits that they may confer. The ALJ's BTA analysis (see Hearing Report, at 78-85) is comprehensive and well-reasoned, and I concur with the ALJ's conclusion that the conditions set forth in the revised draft SPDES permit for this facility represent BTA for minimizing adverse environmental impacts.

APPEAL BY CENTRAL HUDSON GAS AND ELECTRIC CORP.

As previously noted (see, supra, at 5 fn 5), on the morning of the first day of adjudicatory hearings in this proceeding, proposed intervenor Central Hudson Gas and Electric Corp. ("Central Hudson") filed, pursuant to 6 NYCRR 624.5(c), a late petition for full-party status dated and verified November 16, 2005. Central Hudson provides electric delivery services to over 289,000 customers in the mid-Hudson Valley.

By its petition, Central Hudson contended that the measures that Department staff proposed in the revised draft SPDES permit to meet the specific entrainment and impingement reduction levels, as well as the cooling towers proposed by petitioners, have the potential to reduce the available electrical output from the Danskammer facility, thereby impacting

electric reliability. Central Hudson asserted that this potential impact would necessitate investigation and possible modification of Central Hudson's mitigation system plan.

Upon submission of the late petition, the ALJ reserved decision (see AH Tr., at 133). Central Hudson continued to attend the hearings and, on November 28, 2005, requested leave to cross examine petitioners' witness, William Powers (see AH Tr., at 1311-1312). After further argument among the parties, the ALJ denied party status to Central Hudson (see AH Tr., at 1318-1319). The ALJ held that:

"the issue proposed by prospective [intervenor] has been excluded from the hearing and I have considered it before. Therefore, I would find that joining a new issue at this juncture, would delay the proceeding and create unreasonable prejudice for the other parties. For example, there would be a need to identify the issue more specifically, to allow for discovery, and in the case of some parties to retain the specific experts to address this issue"

(AH Tr., at 1318 [as corrected by the ALJ]). Central Hudson filed an expedited appeal from the ALJ's ruling pursuant to 6 NYCRR 624.6(e) and 624.8(d), and I now affirm that ruling.¹³

¹³ The expedited appeal was dated December 2, 2005. Department staff filed a brief in opposition dated December 29, 2005. On January 9, 2006, Central Hudson requested leave to file a limited reply to staff's opposition, and filed its limited reply. By letter dated January 10, 2006, staff requested that Central Hudson's application to file a limited reply be denied. On that same date, Central Hudson submitted a letter with two decisions attached for consideration on its appeal.

In addition to the requirements applicable to petitions for full party status (see 6 NYCRR 624.5[b][2]), a late filed petition for party status must also demonstrate that (1) good cause exists for the late filing, (2) participation by the petitioner will not "significantly delay" the proceeding or "unreasonably prejudice" the other parties, and (3) participation will "materially assist" in the determination of issues raised in the proceeding (6 NYCRR 624.5[c][2]).

For the reasons stated by the ALJ, I agree that granting Central Hudson's late-filed petition would have significantly delayed the proceeding and caused substantial prejudice to the other parties. The parties to this adjudicatory hearing have been actively involved in both this administrative proceeding and civil proceedings before New York State Supreme Court since at least 2002. In this proceeding alone, the parties had already participated in extensive issues conferencing before the ALJ and appeals before the Deputy Commissioner. After the issuance of the Interim Decision establishing the issues for adjudication in this matter, and in the six months leading up to the first day of hearings, the parties were further engaged in extensive discovery and hearing preparation.

I hereby grant Central Hudson's request to file a limited reply, and have considered all the submissions on the appeal.

Insofar as the issue Central Hudson seeks to raise concerns the Department's negative declaration under the State Environmental Quality Review Act ("SEQRA"), Dynegy expressly withdrew the issue before the ALJ. Insofar as it relates to the BTA determination under the federal Clean Water Act, the issue was excluded by the ALJ (see ALJ's rulings dated March 25, 2004 and May 11, 2004). Although Dynegy appealed the ALJ's exclusion of the consideration of costs associated with electric system reliability impacts from the BTA analysis, Dynegy expressly withdrew its appeal of this and other issues by letter dated January 14, 2005.

To consider Central Hudson's petition at the late stage that it was filed would have required reconvening the issues conference, which could have potentially led to further interim appeals and the re-opening of the SEQRA negative declaration, as well as the discovery and hearing preparation process. This, in turn, would have resulted in significant delay and prejudice to the parties in a proceeding that had already reached the final stages of adjudication.

I also conclude that Central Hudson failed to demonstrate good cause for its late filing. Central Hudson was well aware of these on-going proceedings. In 1992, prior to Central Hudson's 2001 transfer of ownership of the facility to Dynegy, Central Hudson filed the SPDES permit renewal application that ultimately culminated in this proceeding. Notice of the legislative public hearings and availability of a draft SPDES permit for public review and comment was published in June 2003, followed by publication in September 2003 of the notice of issues conference, both in a manner consistent with the applicable regulations (see 6 NYCRR 624.3[a]). As late as April 2004, Central Hudson had actual notice of the proceeding as evidenced by the April 8, 2004 letter of John W. Watzka, Central Hudson's employee, which Central Hudson provided to Dynegy to assist in Dynegy's attempt to join electric reliability as an issue for adjudication.

Central Hudson contends that it did not believe it was necessary to become a party because it erroneously believed that after it provided the April 2004 letter to Dynegy, electric reliability was being considered in this proceeding. Central Hudson claims it was not aware until early November 2005 that Dynegy had discontinued litigating the issue. It was Central Hudson's own choice, however, to rely on Dynegy rather than file

its own petition for party status. Central Hudson cannot now claim "good cause" for filing a petition on the first day of the adjudicatory hearing based upon its own erroneous beliefs and its own failure to sufficiently monitor the proceedings to assure itself that Dynegy would continue to litigate the issue.

Central Hudson claims that as the owner of property at the facility, including electrical facilities and rights of way easements, that might have been impacted by the cooling towers proposed by petitioners, due process required "additional notice" to Central Hudson beyond that provided by the June 2003 public notice.¹⁴ Central Hudson argues that the Department was required to provide it such additional notice once the parties knew that cooling towers would be considered in this proceeding. However, because cooling towers will not be required at the facility and, thus, Central Hudson's property interests at the site will not be impacted, any claim that notice was insufficient has been rendered academic. Accordingly, Central Hudson's late filed petition for party status is denied.

¹⁴ As previously noted, a notice of the scheduling of the issues conference was published in September 2003. That notice set forth the requirements, including but not limited to filing deadlines, for petitions for party status.

I hereby direct Department staff to issue the revised draft SPDES permit identified in the adjudicatory hearing record as Exhibit 6 to Dynegy, and at the same time to provide a copy of the issued permit to petitioners.

For the New York State Department
of Environmental Conservation

By: _____/s/_____
Carl Johnson
Deputy Commissioner

Albany, New York
May 24, 2006

STATE OF NEW YORK
DEPARTMENT OF ENVIRONMENTAL CONSERVATION
655 BROADWAY
ALBANY, NEW YORK 12233-1010

In the Matter

- of -

A Renewal and Modification of a State Pollutant Discharge
Elimination System(SPDES) permit pursuant to Article 17 of the
Environmental Conservation Law and Title 6 of the Official
Compilation of Codes, Rules and Regulations of the State of New
York parts 704 and 750 *et seq.*

by

DYNEGY NORTHEAST GENERATION INC.,
ON BEHALF OF DYNEGY DANSKAMMER, LLC
(DANSKAMMER GENERATING STATION),

Permittee.

DEC Case No.: 3-3346-00011/00002
SPDES No.: NY-0006262

Hearing Report

by

_____/s/_____
Daniel P. O'Connell
Administrative Law Judge

Proceedings

Dynegy Northeast Generation, Inc. (Dynegy) is the successor-in-interest to Central Hudson Gas & Electric Co. (Central Hudson), which formerly owned and operated the Danskammer electric generating station (the Facility). The Facility is located on the west shore of the Hudson River at 992-994 River Road in the Town of Newburgh, Orange County (the site). The Facility consists of four single-cycle steam driven turbine units with a total generating capacity of 491 megawatts (MW). Units 1 and 2 burn either natural gas or oil, and Units 3 and 4 burn either coal or natural gas. The Facility withdraws water from the Hudson River for cooling purposes via an intake canal.

Staff of the New York State Department of Environmental Conservation (Department staff) issued a State Pollutant Discharge Elimination System (SPDES) permit for the Facility in 1987. The term for a SPDES permit is five years. To continue operations, permittees must duly file timely and complete renewal applications. (State Administrative Procedure Act § 401[2], Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York [6 NYCRR] 621.13.)

In May 1992, the Facility's former owner, Central Hudson, filed a renewal permit application with the Department. Since that time, Department staff has authorized minor modifications to the Facility's SPDES permit, but did not complete the review of the renewal permit application or issue a renewal permit. In January 2001, Dynegy purchased the Facility from Central Hudson. In November 2002, Department Staff-initiated a modification of the pending SPDES renewal permit application to impose conditions that would require Dynegy to implement various technologies, separately or in combination, to reduce the mortality of fish and other aquatic biota related to entrainment and impingement.

In a letter dated February 5, 2001, Riverkeeper, Inc. petitioned the DEC Commissioner to convene an adjudicatory public hearing about the pending SPDES renewal permit application, and the Staff-initiated proposed modification. In a ruling dated October 1, 2002, the Commissioner denied Riverkeeper's petition. Subsequently, on November 19, 2002, Riverkeeper, Inc., Hudson

River Sloop Clearwater, Inc., Hudson River Fisherman's Association New Jersey Chapter, Inc., Scenic Hudson, Inc., and the Natural Resources Defense Council (NRDC) jointly filed a petition pursuant to Civil Practice Law and Rules (CPLR) article 78 seeking judicial review of the Commissioner's October 1, 2002 ruling, and requesting an order directing Department staff to continue the processing of the pending SPDES renewal permit application, and the Staff-initiated modification. In an Interim Order dated March 25, 2003, Justice E. Michael Kavanaugh, New York State Supreme Court, Ulster County, directed the Department to issue, by July 1, 2003, a notice announcing the availability of a draft SPDES permit for public review and comment, as well as a draft SPDES permit for the Facility.

On June 23, 2003, Department staff, as lead agency, issued a Negative Declaration, pursuant to the State Environmental Quality Review Act (SEQRA [Environmental Conservation Law article 8]). Consistent with the court's March 25, 2003 Interim Order, an Announcement of Public Comment Period and Combined Notice of Complete Application and Legislative Public Hearing dated June 24, 2003 (Announcement and Combined Notice) appeared in the Department's *Environmental Notice Bulletin (ENB)* on June 25, 2003, and in the *Times Herald-Record*, a newspaper of general circulation in the Town of Newburgh, Orange County, on June 29, 2003. As provided for in the Announcement and Combined Notice, Administrative Law Judge (ALJ) Daniel P. O'Connell convened legislative hearing sessions on July 31, 2003 at 2:00 p.m. and 7:00 p.m. at the Newburgh Town Hall to receive unsworn statements from members of the public about the application materials and the draft SPDES permit (Exhibit 3A).¹ About 18 people attended the 2:00 p.m. session, and eleven speakers, including representatives for the Department staff and Dynegy spoke. At the 7:00 p.m. session, about 15 people attended, and seven offered comments. Numerous written comments were filed during the comment period, which closed on August 11, 2003.

A Notice of Issues Conference dated September 5, 2003 appeared in the *ENB* and in the *Times Herald-Record* on September 10, 2003. The September 5, 2003 Notice outlined the requirements to file petitions for either full party status or amicus status, and set October 14, 2003 as the return date for these petitions.

¹ Other documents related to the draft SPDES permit include the SPDES Permit Fact Sheet (Exhibit 3C), the Danskammer Point Generating Station Biological Fact Sheet (Exhibit 3D), and the June 23, 2003 Negative Declaration (Exhibit 3E).

With a cover letter dated October 14, 2003, Riverkeeper, Inc., Scenic Hudson, Inc., and NRDC (collectively referred herein as Petitioners) timely filed a joint petition for full party status with attachments. As scheduled, an issues conference convened on October 29, 2003 at 10:00 a.m. at the Newburgh Town Hall. ALJ Maria E. Villa also presided. Appendix A is a list of appearances of counsel at the issues conference and at the subsequent adjudicatory hearing.

On March 25, 2004, ALJ O'Connell issued a ruling on proposed issues for adjudication and petitions for party status. The March 25, 2004 ruling identified many issues for adjudication and granted full party status to Petitioners. At the request of Dynegy, ALJ O'Connell reopened the record of the issues conference with a memorandum dated April 5, 2004 to consider new information about a failed transformer and its potential impacts on electric system reliability. At the same time, the ALJ granted Dynegy leave to file a motion for reconsideration of a portion of the March 25, 2004 ruling related to proposed draft permit Proposed Condition Nos. 13 and 15 (Exhibit 3A). The parties were provided with an opportunity to respond to Dynegy's submissions concerning electric reliability and the motion for reconsideration. In a ruling dated May 11, 2004, ALJ O'Connell rejected Dynegy's argument that statewide electric reliability is an element of the best technology available (BTA) determination for the Facility, and denied Dynegy's motion for reconsideration.

Meanwhile in early 2004, and independent of this administrative proceeding, Dynegy and Department staff conferred about modifying the existing SPDES permit. The discussion centered on many of the proposed draft permit conditions being considered in this administrative proceeding, which are intended to reduce entrainment and impingement mortality. Subsequently, Department staff modified the Facility's existing SPDES permit on May 18, 2004. The modification, among other things, required Dynegy to develop and evaluate a high-frequency, high-energy sonic fish deterrent device at the Facility's intake canal. The sonic deterrent device would be deployed annually from August 1 until October 1. Other permit conditions required Dynegy to implement a flow reduction program, and to develop a protocol for a tri-axial thermal study of the cooling water discharge.

Petitioners, Dynegy and Department staff timely appealed from the ALJ's March 24 and May 11, 2004 rulings identified above. The parties also timely filed replies to the appeals.

During the pendency of the appeals, Department staff advised the Commissioner, in a letter dated January 14, 2005, that Staff and Dynegy had resolved many of the disputed conditions in the draft SPDES permit (Exhibit 3A) discussed during the October 2003 issues conference. The March 24, 2004 ruling had identified the disputed permit conditions as issues for adjudication (see 6 NYCRR 624.4[c][1][i]). Dynegy confirmed this information in a letter also dated January 14, 2005. As a result, Department staff prepared a revised draft SPDES permit (Exhibit 6), which Staff circulated to the parties with a letter dated January 14, 2005.

Subsequently, Deputy Commissioner Carl Johnson,² as the Commissioner's designated decision maker for this matter, issued an Interim Decision on May 13, 2005 (Exhibit 17). The May 13, 2005 Interim Decision, among other things, identified two issues for adjudication:

1. "[W]hether a closed cycle cooling system can be located on the site and, if so, whether the facility must be retrofitted with such a system to satisfy the 'best technology available' requirements contained in section 316(b) of the federal Clean Water Act and section 704.5 of title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York ('6 NYCRR'). With respect to the adjudication of this issue, the use of properties other than the site or the use of piers or barges in the Hudson River shall not be considered;" and
2. "[W]hether certain assumptions in the Danskammer Alternative Technology Evaluation Model ('DATEM'), which is to be used with respect to the flow reduction and outage program, are reliable." (Interim Decision, May 13, 2005, at 1.)

The ALJs visited the Facility on November 3, 2005 with representatives of all the parties in attendance.

² By memorandum dated February 8, 2005, then Acting Commissioner Denise M. Sheehan delegated decision making authority in this proceeding to Deputy Commissioner Carl Johnson. The February 8, 2005 delegation memorandum was forwarded to the issues conference participants with a letter of the same date.

After an opportunity for discovery, the parties prefiled the proposed direct testimony of their respective witnesses between October 14 and 17, 2005. The parties prefiled the proposed redirect/rebuttal testimony of their respective witnesses on November 7, 2005. Appendix B is a list of witnesses who testified at the adjudicatory hearing. A prehearing conference was held via telephone on November 15, 2005 from 2:00 p.m. until 4:30 p.m. On November 16, 2005, the adjudicatory hearing convened at 10:00 a.m. at the Newburgh Town Hall, and continued thereafter on various days until December 20, 2005. The final session convened at 1:00 p.m. on December 22, 2005, during which a witness and some parties' representatives participated via telephone. Appendix C is a list of the hearing dates and the witnesses examined on those dates.

At the November 16, 2005 session, Robert J. Glasser, Esq., Thompson Hine, LLP, New York appeared on behalf of Central Hudson, and filed a verified petition for full party status dated November 16, 2005. After a discussion on the record, ALJ O'Connell reserved ruling on Central Hudson's petition for full party status. Subsequently, on November 28, 2005, Mr. Glasser referred to 6 NYCRR 624.5(e)(3), and requested an opportunity to cross-examine Petitioners' witness (Transcript [Tr.] 1311-1312.) After further discussion about Central Hudson's petition for full party status, Central Hudson and the parties requested a ruling from the ALJ. (Tr. 1312-1317.) At the November 28, 2005 session, ALJ O'Connell denied Central Hudson's verified petition for full party status dated November 16, 2005, and established a schedule for filing appeals and replies. (Tr. 1318-1321.)

With a cover letter dated December 2, 2005, Central Hudson timely appealed from the ALJ's ruling to deny its verified petition for full party status dated November 16, 2005. With a cover letter dated December 29, 2005, Department staff timely filed a brief in opposition to Central Hudson's appeal. No other parties responded to Central Hudson's appeal. When Central Hudson filed a limited reply with a cover letter dated January 9, 2006, Department staff objected in a letter dated January 10, 2006. With a cover letter dated January 10, 2006, Central Hudson filed copies of two recent decisions, which Central Hudson argued were relevant to its appeal.

After a telephone conference call on January 5, 2006, the ALJ established a schedule for the parties to file proposed errata to correct the transcript of the adjudicatory hearing, and to submit briefs and replies. Closing briefs were timely received from Petitioners, Dynegy and Department staff. Replies

were timely filed from Petitioners, Dynegy and Department staff. The parties were provided an opportunity to file comments and objections about proposed errata by March 20, 2006. No objections to the parties' proposed errata were received. Whereupon, the record of the proceeding closed on March 20, 2006.

Findings of Fact

I. Permittee and Facility Description

1. Dynegy Northeast Generation, Inc. (Dynegy) is the successor-in-interest to Central Hudson Gas & Electric Co. (Central Hudson), which formerly owned and operated the Danskammer electric generating station (the Facility).
2. The Facility is located on the west shore of the Hudson River (River Mile 65) at 992-994 River Road in the Town of Newburgh, Orange County (the site).
3. The Facility consists of four single-cycle steam driven turbine units with a total generating capacity of 491 megawatts (MW). Units 1 and 2 burn either natural gas or oil, and Units 3 and 4 burn either coal or natural gas.
4. The Facility withdraws water from the Hudson River by means of an intake canal for cooling purposes, among other things. Water passes through the Facility once before it is discharged back to the river, which is characterized as a once-through cooling system. Because the water does not come into contact with the electric generating equipment during the cooling process, it is referred to as non-contact cooling water.
5. The intake canal is located on the north side of the site. It is open and at river level. The intake canal is 11 feet deep and 450 feet long. The initial width of the canal is 115 feet, and the canal quickly narrows to 34 feet. At the present time, water is drawn into the canal by single speed pumps located near the Facility. Units 1 and 2 each have two cooling water pumps, and each pump is rated at 21,000 gallons per minute (GPM). Unit 3 has two pumps and each pump is rated at 41,000 GPM. Unit 4 has three pumps and each pump is rated at 50,000 GPM. The Facility's total maximum design flow is 316,000 GPM or about 455 million gallons per day (MGD).

6. A series of traveling screens are located in front of the cooling water pumps. For Units 1, 2 and 4, the mesh on the traveling screens is 3/8 inch square. For Unit 3, the mesh on the traveling screens is 1/8 inch square. The purpose of the screens is to prevent debris from entering the pump chambers and condensers. The screens are continuously rotated and sprayed with high pressure water to flush the screens. The wash water is directed back to the river through a sluice that exits through the bulkhead in front of the plant. This point source is identified as Outfall 001 in both the current, and the revised draft SPDES permit, which is identified in the hearing record as Exhibit 6.
7. After non-contact cooling water circulates through the Facility, it is discharged from outfalls located on the south side of the site. Units 1 and 2 discharge non-contact cooling water via Outfall 002. Unit 3 discharges non-contact cooling water at Outfall 003, and Unit 4 discharges at Outfall 004. The three outfalls (002, 003 and 004) for the non-contact cooling water are submerged and are located adjacent to each other.
8. The Facility has other outfalls, and the discharges from these outfalls are regulated by the current SPDES permit, and would continue to be regulated as described in the revised draft SPDES permit. Sanitary waste water is discharged via Outfall 005 after treatment at the Facility's sanitary waste water treatment plant, which is located south of the powerhouse. The Facility generates industrial waste water when components are cleaned, and from normal operations such as boiler blowdowns. In addition, leachate from the Danskammer Point ash landfill and settlement ponds, and contact runoff from the active and reserve coal piles are collected and treated prior to discharge. After treatment and collection, the waste water is discharged from Outfalls 006, 06A, and 019, and reaches the Hudson River via a common discharge channel located on the north side of the site. The waste water discharges from these and other outfalls at the site related to stormwater management are regulated by the current SPDES permit and would continue to be regulated as outlined in the revised draft SPDES permit.

II. Cooling Towers, Locations and Configurations

9. Petitioners proposed eight potential design configurations to fully retrofit the Facility with a closed-cycle cooling system, and four potential design configurations to retrofit

electric generating Units 3 and 4 (*i.e.* the partial retrofits). The various proposed retrofit configurations are depicted in Exhibit 19.

10. Petitioners selected plume-abated wet cooling cells, model F488-6.0-6, by Marley SPX Cooling Technologies, Inc. (Marley). The dimensions of these cooling cells are 48 feet wide by 48 feet long by 49 feet high.
11. To fully retrofit the Facility, Configuration Nos. 1 through 6 would use a total of 14 wet cooling cells grouped into three towers, and located throughout the site. Using the Marley model identified above, Units 1 and 2 would each need two wet cooling cells. Unit 3 would need four wet cells, and Unit 4 would need six wet cells.
12. For Configuration Nos. 7 and 8, Unit 3 would be retrofitted with a series of dry cooling cells, which are also referred to as air cooled condensers (ACCs). The dimensions of each ACC unit would be 44 feet long by 44 feet wide. The height of the ACCs unit is unknown.
13. Each wet cooling tower has two pipelines associated with it. The cooling water return pipe extends from the condenser of the individual electric generating unit to the wet cooling tower, and transports heated water from the condenser to the wet cooling tower.
14. As the heated water passes through the wet cooling cells, the water cools. The cooled water is collected at the base of the cooling tower and transported via the second pipeline, referred to as the cooling water discharge pipe, to the intake basin. The routes for the cooling water return and the cooling water discharge pipelines for a particular configuration would depend on the existing infrastructure and the proposed location of the cooling towers on the site.
15. If the Facility is fully retrofitted with a closed-cycle cooling system, the existing intake basin would be sealed off from the current intake canal, and reconfigured into four separate intake basins using precast partitions. Each newly created intake basin would receive the cooling water discharge pipe from its respective wet cooling tower.
16. The size of the cooling water return and the cooling water discharge pipes depends on the size of the electric

generating unit. For Units 1 and 2, the cooling water return and discharge pipes would each be 40 inches in diameter for each unit. For Unit 3, the cooling water return and discharge pipes would each be 60 inches in diameter. For Unit 4, the cooling water return and discharge pipes would each be 78 inches in diameter.

17. Petitioners identified seven potential areas on the Danskammer site to locate closed-cycle cooling towers. The first potential area (Area 1) is north of the waste water treatment storage lagoons between the right-of-ways for the CSX railroad and the Federal Aviation Administration (FAA) radio beacon. Area 1 is located in the A-3 flood plain.
18. The second potential area (Area 2) is east-southeast of the area reserved for the FAA beacon. Area 2 is also in the A-3 flood plain, and is the site of a decommissioned waste water treatment storage lagoon that is presently covered with scrub forest vegetation.
19. The third area (Area 3) identified as a potential location for a wet cooling tower is over the intake canal. If the Facility is partially or fully retrofitted, Petitioners propose to decommission the intake canal, backfill it, and put a cooling tower at this location.
20. The fourth potential area (Area 4) is west of the intake canal. Presently, a one-story metal warehouse building occupies this area. The building would have to be razed before a cooling tower could be placed at this location.
21. The fifth potential area (Area 5) for a cooling tower is along the eastern wall of the powerhouse. Area 5 would be used to locate dry cooling cells (*i.e.* ACCs) as part of Configuration Nos. 7 and 8, as well as Partial Retrofit Configuration No. 4. The dry cooling units on Area 5 would be raised 40 feet above grade, which would permit light and medium weight vehicles to pass underneath them. The overall height of the ACC tower is unknown.
22. The sixth proposed location (Area 6) is an area south of the powerhouse between the common air emission stack for Units 3 and 4, and the sand filter for the sanitary waste water system. To place a cooling tower on Area 6, a portion of the discharge pipe from the sanitary waste water system would have to be relocated.

23. The seventh proposed location (Area 7) is a triangular area west of the right-of-way for the CSX railroad tracks and between the right-of-ways for the overhead transmission lines owned by Central Hudson (115 kilovolts [kV]) and New York Power Authority (NYPA) (345 kV). If a cooling tower is located on Area 7, then the cooling water return pipeline from the electric generating units to the cooling tower and the cooling water discharge pipeline from the cooling tower to the intake basin would need to pass under the CSX railroad tracks and cross a natural gas pipeline.
24. For Configuration No. 1, 14 wet cooling cells (Marley F488-6.0-6) would be arranged into three towers. Two cells would be placed on Area 1, near the FAA beacon, and would be used to cool either electric generating Unit 1 or Unit 2. For electric generating Unit 3, a single row of four cells would be placed on Area 2. For Unit 4, and either Unit 1 or Unit 2, a single row of eight cells would be placed over the decommissioned intake canal, which is identified above as Area 3.
25. For Configuration No. 2, 14 wet cooling cells (Marley F488-6.0-6) would be arranged into three towers. For Units 1 and 2, a single row of four cells would be placed on the decommissioned waste water treatment lagoon (Area 2). For Unit 3, a single row of four cells would be placed on Area 4, where a one-story metal warehouse building is currently located. The cooling tower for Unit 4 would consist of six cells arranged in a 3x2 configuration, and located on Area 7, which is west of the railroad tracks.
26. Configuration No. 3 would consist of 14 wet cooling cells (Marley F488-6.0-6) grouped into three towers. For Units 1 and 2, a single row of four cells would be located west of the intake canal (Area 4). For Unit 3, four cells would be located south of the powerhouse between the common emission stack for Units 3 and 4, and the sand filter for the sanitary waste water system (Area 6). The cooling tower for Unit 4 would consist of six cells arranged in a 3x2 configuration on Area 7, which is west of the railroad tracks.
27. Configuration No. 4 would consist of 14 wet cooling cells (Marley F488-6.0-6) grouped into three towers. A single row of four wet cooling cells would be located on Area 4 for Units 1 and 2. For electric generating Unit 3, four cells would be arranged in a single row on Area 7, west of the

railroad tracks. The cooling tower for Unit 4 would consist of six wet cells arranged in a single row on Area 6, which is south of the powerhouse.

28. Configuration No. 5 would consist of 14 wet cooling cells (Marley F488-6.0-6), grouped into three towers. For Units 1 and 2, a single row of four cells would be placed on Area 2, which is the decommissioned waste water treatment storage lagoon. For electric generating Unit 3, a single row of four wet cells would be placed west of the intake canal, which is Area 4. The six wet cooling units for Unit 4 would be placed on Area 6, which is south of the powerhouse.
29. Configuration No. 6 would consist of 14 wet cooling cells (Marley F488-6.0-6), grouped into three towers. To cool Units 1 and 2, a single row of four cells would be placed on the decommissioned waste water treatment storage lagoon (Area 2). For Unit 3, four cells would be arranged in a single row and located south of the powerhouse on Area 6. For electric generating Unit 4, a single row of six cells would be placed over the current site of the intake canal, which is Area 3.
30. Configuration No. 7 would consist of a combination of 12 wet cooling cells and six ACCs. A single row of six wet cells would be placed over the current site of the intake canal (Area 3). Four of the six wet cells would cool Units 1 and 2, and the remaining two wet cells would be used in combination with six ACCs to cool Unit 3. For Unit 3, two of the previously identified wet cells would be connected in parallel to a single row of six ACCs that would be placed along the east wall of the powerhouse (Area 5). The cooling tower for Unit 4 would consist of six cells located south of the powerhouse on Area 6.
31. Configuration No. 8 would consist of a combination of ten wet cooling cells and 12 ACCs. Units 1 and 2 would be cooled with a set of four wet cells placed on Area 7, west of the railroad tracks. Unit 4 would be cooled with a set of six wet cells placed on Area 6. Unit 3 would be cooled using two sets of ACCs. The first set would be a single row of six cells, placed over the current site of the intake canal (Area 3). The second set would be another row of six cells placed along the east wall of the powerhouse (Area 5).
32. Petitioners proposed four partial retrofit configurations. For each partial retrofit, Units 3 and 4 would be converted

from a once-through cooling system to a closed-cycle cooling system. Units 1 and 2 would not be converted and would retain their respective once-through cooling systems.

33. With respect to the partial retrofits, Partial Retrofit Configuration Nos. 1 through 3 would use a total of ten wet cooling cells grouped into two towers. Partial Retrofit Configuration No. 4 would consist of a combination of eight wet cooling cells and six ACCs.
34. The common intake basin would be reconfigured to permit Units 1 and 2 to withdraw water from the river via the existing auxiliary (or emergency) intake on a continuous basis for once-through cooling purposes while providing a common closed-cycle cooling water intake basin for Units 3 and 4.
35. Partial Retrofit Configuration No. 1 would consist of ten wet cooling cells grouped into two towers. For Unit 3, a single row of four cells would be placed over the decommissioned waste water treatment storage lagoon (Area 2). For Unit 4, a single row of six cells would be placed over the current site of the intake canal, which is Area 3.
36. Partial Retrofit Configuration No. 2 would consist of ten wet cooling cells grouped into two towers. For Unit 3, four cells would be arranged in a single row and placed on Area 7, which is west of the railroad tracks. For Unit 4, six cells arranged in a single row would be located south of the powerhouse on Area 6.
37. Partial Retrofit Configuration No. 3 would consist of ten wet cooling cells grouped into two towers. For Unit 3, a single row of four cells would be placed to the west of the intake canal on Area 4. For electric generating Unit 4, six cells arranged in a single row, would be located south of the powerhouse on Area 6.
38. Partial Retrofit Configuration No. 4 would consist of a combination of eight wet cells and six ACCs. For Unit 3, two of the eight wet cells would be placed on the western side of the intake canal (Area 4). In addition, Unit 3 would be connected in parallel to a single row of six ACCs placed along the east wall of the powerhouse (Area 5). The cooling tower for Unit 4 would consist of six wet cells located south of the powerhouse on Area 6.

III. Cooling Tower Size - Unit 4

39. The proposed closed-cycle cooling tower for Unit 4 would be designed to provide a heat rejection rate of approximately 1,105 million British thermal units per hour (MMBtu/hr).
40. In order to design the closed-cycle cooling tower for Unit 4 to meet the estimated heat rejection rate, Petitioners expert, William Powers, P.E. (Powers Engineering [San Diego, CA]), reviewed the specifications for two different cell models manufactured by Marley Cooling Technologies, Inc. (Marley), which are identified by model numbers F488 and F489. The dimensions of the Marley F488 cell are 48 feet long by 48 feet wide by 49 feet high. The dimensions of the Marley F489 cell are 54 feet long by 48 feet wide by 49 feet high.
41. To retrofit the once-through cooling system for Unit 4, Mr. Powers proposed to use six Marley F488 cells. Mr. Powers did not select the Marley F489 cooling cell, in part, because the length of the six cell tower would not fit on the site (6 cells x 54 feet long = 324 feet). Each Marley F488 cooling cell would have six feet of film fill and extra fan blades. The dimensions of the proposed cooling tower for Unit 4 would be 288 feet long (6 cells x 48 feet long = 288 feet) by 48 feet wide, which would occupy an approximate area of 13,824 square feet.
42. Film fill is a material that can be added to a cooling cell to improve its thermal efficiency. However, film fill can foul when it becomes plugged. When film fill is fouled, the thermal efficiency of the cooling cell decreases substantially. On occasion, the weight of the water trapped in the clogged fill can cause the film fill to collapse into the collection basin. Shorter amounts of film fill, on the order of four feet or less, are easier to clean than deeper amounts, such as six feet.
43. Generally, steam-turbine generators can operate over a modest range of backpressures. Each turbine model, however, has a design point for optimum efficiency. Operating a turbine at backpressures greater than its design point reduces its electric generating efficiency.
44. For Units 3 and 4, the turbine backpressure design points are, respectively, 1.0 inch of mercury (Hg) and 1.5 inches of Hg.

45. Data collected at the Facility show that under peak summer conditions with the once-through cooling system, the steam turbine backpressure for Unit 4 has ranged from 1.3 to 1.5 inches of Hg.
46. Turbine backpressure is directly related to the effectiveness of the cooling system used to cool the steam turbine generating unit.
47. Mr. Powers estimated the turbine backpressure for Unit 4 retrofitted with a closed-cycle cooling system at peak summertime conditions. For this analysis, Mr. Powers assumed an approach temperature of 13°F,³ a wet bulb temperature of 76°F, a hot cooling water temperature of 109°F, and a saturated steam temperature of 117°F, based on a terminal temperature difference (TTD) of 8°F.⁴ Under these conditions, the estimated turbine backpressure would be 3.2 inches of Hg.
48. Mr. Powers revised his estimate of the turbine backpressure for Unit 4 retrofitted with a closed-cycle cooling system at peak summertime conditions. In the revision, Mr. Powers assumed an approach temperature of 13°F, a wet bulb temperature of 76°F, and a hot cooling water temperature of 109°F. Mr. Powers reduced the saturated steam temperature from 117°F to 115°F, based on a TTD of 6°F. Under these conditions, the estimated turbine backpressure would be 3.0 inches of Hg.
49. After consulting the on-line computer program available on the Marley website, David Grogan (D.B. Grogan Associates, LLC [Gloucester, MA]), Dynegy's expert witness, developed an alternative closed-cycle cooling tower design for Unit 4. Mr. Grogan reduced the approach temperature from 13°F to 8°F, and kept the values for the other design parameters selected by Mr. Powers constant (*i.e.* the heat inputs, flows, and design wet bulb temperature). The resulting alternative configuration would consist of eight Marley F489 cells with four feet of film fill. With the alternative configuration developed by Mr. Grogan, the estimated steam

³ See footnote 15 for a definition of the term "approach temperature."

⁴ See footnote 14 for a definition of the term "terminal temperature difference."

turbine backpressure at peak summertime conditions would be 2.6 inches of Hg.

50. The length of the alternative cooling tower for Unit 4 developed by Mr. Grogan would increase from 288 feet (6 cells x 48 feet long [Marley F488] = 288 feet) to 432 feet (8 cells x 54 feet long [Marley F489] = 432 feet).
51. A closed-cycle cooling tower consisting of six Marley F488 cells with six feet of film fill and an approach temperature of 13°F would contribute to excessively high turbine backpressures that would not adequately meet the original design standards for the Unit 4 steam-driven turbine. If retrofitted with six Marley F488 cells, as described above, the resulting operating conditions, over time, could damage the Unit 4 steam-driven turbine given the additional mechanical stress resulting from the substantially elevated turbine backpressure. As a result, the proposed closed-cycle cooling tower consisting of six Marley F488 cells with six feet of film fill and an approach temperature of 13°F, would be significantly and, therefore, unacceptably undersized.
52. Given that the proposed closed-cycle cooling tower consisting of six Marley F488 cells with six feet of film fill and an approach temperature of 13°F would be significantly undersized, and because the above described alternative cooling tower designs⁵ for Unit 4 would not fit on the site, proposed Configuration Nos. 1, 4, 5, 6, 7 and 8, as well as Partial Retrofit Configuration Nos. 1, 2, 3 and 4 are not available with respect to the best available technology determination.

IV. Flue Gas Desulfurization (FGD)

53. The efficiency level of Units 3 and 4 would decrease, if these electric generating units are retrofitted with a closed-cycle cooling system. The decrease in efficiency would increase net air emissions. Increasing net air emissions would subject the Facility to additional

⁵ In § II.E of the Discussion, two alternative cooling tower designs are addressed. Mr. Powers explained that he did not choose the Marley F489 model because its length would be too long (§ II.E.1). Mr. Grogan's alternative design is described in Finding of Fact No. 49 and in § II.E.2.

requirements under the federal Clean Air Act such as Prevention of Significant Deterioration (PSD) and New Source Review. The anticipated net increase of SO₂ emissions would range from 92.0 tons per year to 372.2 tons per year, which is greater than the PSD threshold limit of 40 tons per year.

54. If the Facility is retrofitted with a closed-cycle cooling system, Dynegy would have to install the best available control technology (BACT) to reduce the expected net increase in SO₂ emissions. For a coal fired electric generating facility, BACT to reduce SO₂ emissions would be a flue gas desulfurization (FGD) system.
55. If the Facility is retrofitted with a closed-cycle cooling system, the net emissions of NO_x would increase, and would range from 35.0 tons per year to 142.1 tons per year. With respect to NO_x emissions, the PSD threshold limit for NO_x is 40 tons per year. If, due to the proposed retrofit, the net change in NO_x emissions increases by more than 40 tons per year, Dynegy would have to install BACT to reduce this emission increase. BACT to reduce NO_x emissions would be a selective catalytic reduction (SCR) system. The record of this proceeding does not include any information about the components of an SCR system.
56. Sargent and Lundy, LLC, provided representatives from Dynegy with a sketch of the components for an FGD system, which was forwarded to Dynegy's witness, Matthew Allen, RLA (Saratoga Associates, PC [Saratoga Springs, NY]), who then transferred the information provided in the sketch to Exhibit 114.
57. In Exhibit 114, portions of the emergency gypsum building and the gypsum house, which are components of the FGD system provided by Sargent and Lundy, LLC, would be located at the site of the decommissioned fuel oil storage tank. Other components of the FGD system depicted in Exhibit 114 would generally occupy the space where Mr. Powers proposed to locate a closed-cycle cooling tower (*i.e.* Area 6). In particular, the inactive limestone storage area would be located on the currently open area south of the powerhouse and north of the sanitary waste water treatment system, and between the roadway and the bank of the Hudson River.
58. The components of the FGD system presented in Exhibit 114 would occupy about 60,000 square feet. Some of the significant factors considered in sizing the FGD system for

Units 3 and 4 at the Facility were: (1) the sulfur content of the coal; (2) the size of the two units; (3) the heat input of the units; (4) sources of limestone (a reagent); and (5) options for storing the gypsum (a product). The FGD system shown in Exhibit 114 is properly sized for Units 3 and 4.

59. Not only would retrofitting Unit 4 with a closed-cycle cooling system require a larger cooling tower than originally proposed, it would also require Dynegy to install additional pollution control equipment. Dynegy would need to install an FGD system to reduce the expected net increase in SO₂ emissions resulting from the proposed retrofit. Dynegy may need to install an SCR system to control the potential increase in NO_x emissions. The installation of the FGD system at the Facility, separate from the need for a larger cooling tower and the additional space associated with an SCR system, would preclude the installation of any cooling towers south of the powerhouse on what has been identified above as Area 6. As a result, Configuration Nos. 3, 4, 5, 6, 7 and 8, as well as Partial Retrofit Configuration Nos. 2, 3 and 4 are not available with respect to the best technology available determination.

V. Cooling Towers on Area 2

60. As described above (see Finding No. 18), Area 2 is located on the north side of the site, and is the site of a decommissioned waste water treatment storage lagoon that is presently covered with scrub forest vegetation.
61. Based on Exhibit 19, the northern side of the proposed four-cell cooling tower placed on Area 2 would line up with the northern side of the waste water treatment building. At this location, the eastern end of the proposed four-cell cooling tower would be about 25 feet from the waste water treatment building. The western end of the cooling tower would extend past the current waste water treatment lagoons by about 30 feet.
62. Lawrence R. Wilson testified on behalf of Department staff. He is a Biologist in the Steam Electric Unit with the Department's Division of Fish, Wildlife and Marine Resources. In his professional capacity, Mr. Wilson has visited the Facility many times.

63. Upon reviewing Exhibit 19, Mr. Wilson initially concluded there would be sufficient space on Area 2 to accommodate a four-cell cooling tower. Subsequently, Mr. Wilson visited the site. During the site visit, Mr. Wilson stood with his back to the northwest corner of the waste water treatment building and looked west toward the FAA beacon and the railroad tracks. He observed that the crest of the river bank extended farther south than depicted in Exhibit 19 into Area 2.
64. Exhibit 199 is an aerial photograph of the Facility taken on December 17, 2002. A comparison of Exhibit 199 with Exhibit 19, and Mr. Wilson's unrefuted testimony demonstrate that the northern shore of the site is actually farther south than what is depicted on Exhibit 19. As a result, Area 2 would not be wide enough to accommodate the cooling tower proposed by Mr. Powers. Given the anticipated length of the proposed four-cell cooling tower, there is not sufficient space to move the proposed cooling tower farther south due to the location of the current, active waste water treatment lagoons and associated facilities. As a result, Configuration Nos. 1, 2, 5 and 6, as well as Partial Retrofit Configuration No. 1 are not available with respect to the best technology available determination.

VI. Danskammer Alternative Technology Evaluation Model (DATEM)

65. DATEM is a computer calculation tool that Dynegy would use to quantitatively assess compliance with the performance standards outlined in the revised draft SPDES permit for reducing entrainment and impingement mortality. DATEM operates on the principle that entrainment and impingement mortality can be reliably estimated based on: (1) the volume of cooling water withdrawn; (2) the weekly density of organisms present in the vicinity of the intake structure; and (3) the fractional mortality of organisms involved in the intake.
66. Fractional mortality is the percentage of aquatic organisms that do not survive entrainment and impingement. The fractional mortality rate associated with entrainment depends on the mechanical and thermal stresses that aquatic organisms are exposed to as they pass through the cooling water system. Mechanical stress occurs from shear, turbulence, pressure changes, and contact with surfaces of the cooling system components. Thermal stress occurs when an organism is heated beyond its zone of thermal tolerance.

67. On a weekly basis, DATEM calculates the mortality associated with entrainment and impingement based on historical data that estimates the concentration of fish species and their various life stages in the water column during a particular week. The estimate is then adjusted for survival. The adjusted result is compared with a baseline mortality level, which is assumed to be 100%.
68. DATEM incorporates fractional mortality estimates for six fish species: striped bass, white perch, American shad, Blueback herring, Alewife and bay anchovy. However, extensive monitoring data show that bay anchovy have low involvement with the Facility. The distribution of American tomcod in the reach of the Hudson River near the Facility is similar to that of the bay anchovy. Therefore, bay anchovy and tomcod are not considered in DATEM assessments.
69. To quantitatively assess compliance with the performance standards outlined in the revised draft SPDES permit for reducing entrainment and impingement mortality, DATEM compares a baseline flow with the actual volume of water withdrawn by the Facility. The baseline flow is calculated by using the full-flow capacity. Full-flow capacity means the total volume of cooling water withdrawn when all pumps at the Facility are continuously operating at full capacity every day of the year.
70. Using the full-flow baseline would allow Department staff to evaluate reductions from the Facility's potential to entrain aquatic organisms. Also, it would allow Department staff to standardize the compliance requirements associated with entrainment and impingement mortality for all facilities in the state. Finally, the full-flow baseline recognizes that any reduction in flow, regardless of the reason, has the effect of reducing entrainment mortality.

VII. Entrainment Survival

71. Entrainment survival varies by species and life stage, and among facilities. Generally, fish larvae have a very high natural mortality rate.
72. Entrainment monitoring was conducted at the Facility from 1974 through 1987. In particular, Steven M. Jinks, Ph.D., who is presently a Senior Scientist/Associate with ASA Analysis and Communication, Inc. (Washingtonville, NY), supervised intensive weekly entrainment sampling from 1982

to 1987. These studies were designed to describe species composition, abundance, seasonal and daily distribution patterns, and the period of entrainment. Because sampling was more intensive between 1982 and 1987, and because the 1982 to 1987 sampling period is more recent than the prior sampling studies from the 1970s, the data collected from 1982-1987 are the basis for the entrainment density inputs for DATEM.

73. For the 1982-1987 entrainment monitoring studies at the Facility, samples were collected at the beginning of the intake canal behind the trash racks. After collection, preserved samples were sent to the laboratory, where organisms were sorted, identified by species and life stage, and counted.
74. For each species and life stage, DATEM tracks two discharge temperature parameters, referred to as X1 and X2. X1 is the temperature below which no mortality would result. X2 is the temperature above which 100% mortality is assumed. Between these two discharge temperatures, DATEM assumes that mortality increases directly with temperature. X1 and X2 are unique for each fish species and their various life stages.
75. Thermal tolerance studies were conducted at the Facility during the 1970s. The results of these studies generally demonstrate that the more important factors in determining entrainment mortality associated with thermal stress are the exposure temperature and, to a lesser degree, the length of exposure. Generally, the thermal stress component associated with entrainment mortality is typically negligible when temperatures in the cooling system remain below the threshold temperature (*i.e.* < X1).
76. The time periods for the data tracked by DATEM vary. For example, flow, as well as the water intake and discharge temperatures for each electric generating unit at the Facility are monitored daily. The historical data related to the density of organisms in the water column, which are the results of the entrainment survival studies undertaken at the Facility in the 1980s, are presented in weekly increments (Monday through Sunday).
77. Because adjustments for entrainment survival are presented on a weekly basis rather than on a daily basis, estimates of entrainment mortality associated with thermal stress for a

particular unit could be underestimated when a particular unit operates for less than seven days during a particular Monday to Sunday period, and if the resulting average temperature is based on that same seven-day period.

78. Estimates of entrainment mortality associated with thermal stress, however, depend not only on the discharge temperature, but also on flow. The more significant variable in estimating entrainment mortality is flow because, on a weekly basis, the density of entrained organisms is directly related to flow. As a result, the average weekly flow, which accurately reflects the density of the organisms entrained, would moderate potential temperature underestimations with respect to entrainment mortality estimates.

VIII. Temperature

79. DATEM uses daily temperature measurements collected at the City of Poughkeepsie water supply intakes, which are located approximately 10 miles upstream from the Facility. The temperature data from the Poughkeepsie water supply intakes provides an estimate of the water temperature at the Facility's intake.
80. The temperature data from the Poughkeepsie water intakes are used in two ways. First, the data determine the amount of water that the Facility would need for cooling purposes. When water temperatures are low, the Facility would draw less water from the Hudson River to cool the Facility compared to when the water temperature is higher. Second, the data from the Poughkeepsie water intakes determine the temperatures to which entrained organisms would be exposed, and thus affect the thermal component of the entrainment fractional mortality rate.
81. Based on the unrefuted expert testimony of Charles V. Beckers, Jr., who is a Senior Project Manager for Mathematical Modeling in the Natural Resource Management and Permitting Section of HDR/LMS (formerly Lawler, Matusky & Skelly Engineers, LLP), the temperature data collected at the Poughkeepsie water supply intakes are reliable. The data provide a representative measurement of the near-surface water temperature in the Hudson River at the time the measurements are taken.

IX. Best Technology Available

82. The Facility's cooling water intake structure may cause adverse environmental impacts to the aquatic organisms of the Hudson River.
83. Sonic deterrent devices have successfully reduced the number of herring impinged at cooling water intake structures. The sonic deterrent equipment that would be employed at the Facility would use a frequency targeted to repel juvenile American shad, Blueback herring and Alewife as they migrate down the river on their way to the ocean. Sonic deterrence would be an available technology for the Facility.
84. The flow reduction and outage program outlined in the revised draft SPDES permit would limit the capacity of the Facility's cooling water intake structure. This program would be an available technology for the Facility.

Discussion

I. Draft SPDES Permit Conditions

Like the SPDES permit currently in effect, the revised draft SPDES permit (Exhibit 6) would regulate the waste water discharges from all of the Facility's outfalls. For example, sanitary waste water is discharged via Outfall 005 after treatment at the Facility's sanitary waste water treatment plant located south of the powerhouse. The Facility generates industrial waste water when components are cleaned, and from normal operations such as boiler blowdowns. In addition, leachate from the Danskammer Point ash landfill and settlement ponds, and contact runoff from the active and reserve coal piles are collected and treated prior to discharge. After collection and treatment, the waste water is discharged from Outfalls 006, 006A, and 019, and reaches the Hudson River via a common discharge channel located on the northern side of the site. The waste water discharges from these, and other outfalls at the site related to stormwater management, are regulated by the SPDES permit currently in effect, and would continue to be regulated as outlined in the revised draft SPDES permit (Exhibit 6).

For cooling purposes, water is withdrawn from the Hudson River via an intake canal. The mouth of the canal is located at river level on the northeast corner of the site. After the non-contact cooling water circulates through the Facility, it is

discharged from outfalls located on the south side of the site. Units 1 and 2 discharge non-contact cooling water via Outfall 002. Unit 3 discharges non-contact cooling water at Outfall 003, and Unit 4 discharges at Outfall 004. The three outfalls (002, 003 and 004) for the non-contact cooling water are submerged and are located adjacent to each other. The adjudicatory hearing focused on disputes associated with installing equipment and implementing operational practices that would limit the amount of water withdrawn from the Hudson River for cooling purposes.

Conditions proposed in the revised draft SPDES permit would require Dynegy to monitor mortality from entrainment and impingement (Exhibit 6, Proposed Conditions Nos. 8 and 9). Entrainment occurs when small benthic, planktonic and nektonic organisms, including early life stages of fish and shellfish, are drawn through cooling water intake structures and into the cooling system. As entrained organisms pass through a plant's cooling system, they may be subject to fatal mechanical, thermal and toxic stresses. Impingement takes place when organisms are trapped against intake screens by the force of the water passing through the cooling water intake structure. This can result in physical harm such as starvation, exhaustion, asphyxiation, and descaling.

During the first two years of the five-year term of the revised draft SPDES permit, Dynegy would be required to reduce entrainment mortality by at least 70% and to reduce impingement mortality by at least 80% (Exhibit 6, Proposed Condition No. 11a, at 15 of 25). During the subsequent three years of the permit term, Dynegy would be required to reduce entrainment mortality by at least 80% and to reduce impingement mortality by at least 85% (Exhibit 6, Proposed Condition No. 11b, at 15 of 25).⁶ Dynegy would meet these goals, in part, by operating the Facility in a manner that withdraws the minimum volume of water from the Hudson River necessary to provide cooling while complying with the thermal discharge limits outlined in the permit. Dynegy would use the Danskammer Alternative Technology Evaluation Model (DATEM) to verify flow, the temperature of the discharge, and reductions in entrainment and impingement mortality.

⁶ In the discussion concerning the baseline flow in DATEM (§ III.A), the percentage reductions outlined in Proposed Condition Nos. 11a and 11b are referred to as the performance standards for limiting mortality from entrainment and impingement.

To reduce flow further, Dynegy would be required to evaluate: (1) the installation of an additional half capacity cooling water pump, and (2) the retrofiting of variable speed motor controls to the existing cooling water pumps at Unit 4 (Exhibit 6, Proposed Condition No. 13). Three years after the effective date of the proposed revised draft SPDES permit, Dynegy would be required to submit a list that includes equipment and operational practices, which when implemented individually or in combination would have the potential to reduce entrainment mortality of fish eggs and larvae by at least 80%, and impingement mortality of fish by at least 90% (Exhibit 6, Proposed Condition No. 14).

In conjunction with flow reductions, Dynegy would also be required to install and evaluate a high-frequency, high-energy sonic fish deterrent device at the opening of the intake canal. The sonic deterrent device would be installed annually from August 1 to October 31 (Exhibit 6, Proposed Condition No. 10). A similar permit condition was incorporated into the permit currently in effect as part of the May 2004 modification.

II. Cooling Towers

As noted above, the Deputy Commissioner determined that whether the Facility should be retrofitted, either in whole or in part, with a closed-cycle cooling system would be an issue for adjudication, based on the proof offered in Petitioners' request for full party status. If the Facility is fully retrofitted with a closed-cycle cooling system, about 2% of the current amount of water used in the once-through cooling system would be required. (Tr. 364.) The environmental benefit associated with reduced water withdrawals would be substantial reductions in the number of aquatic organisms that could be entrained and impinged by the Facility's cooling system.

The threshold issue is whether there is sufficient space on the site to accommodate any closed-cycle cooling system. Related issues include how the closed-cycle cooling system retrofit designs proposed by Petitioners would impact the Facility's electric generating capacity and air emissions from the Facility. If there is sufficient space on the site for closed-cycle cooling towers, then an additional issue is whether the costs associated with the proposed retrofit would be wholly disproportionate to the environmental benefits to be gained compared to other available alternative technologies.

On behalf of Petitioners, William Powers, P.E., (Powers Engineering [San Diego, CA]) developed the retrofit design configurations and presented the configurations at the adjudicatory hearing. Mr. Powers proposed eight potential design configurations to fully retrofit the Facility with a closed-cycle cooling system, and four potential design configurations to retrofit electric generating Units 3 and 4 (*i.e.* the partial retrofits). The plans for the proposed configurations are collectively identified in the hearing record as Exhibit 19. On Exhibit 19, Mr. Powers superimposed the design configurations on a site plan map, and added caption boxes to describe some of the features associated with each proposed configuration. (Tr. 364.) Additional details about the proposed configurations are presented in Exhibits 30, 31, 38, 39, 45, 49, 56 and 58.

Mr. Powers explained that the Petitioners retained him to examine the feasibility of retrofitting the Facility, either in whole or in part, with a closed-cycle cooling system, and the costs associated with retrofitting the Facility. In developing the proposed retrofits, Mr. Powers considered the cooling cell model, pipes and piping runs, the pumps and pumphouse, the surface condenser, obstacles in and above the ground, as well as a plan to operate the Facility's once-through cooling system during the construction of the retrofits as major design elements. (Tr. 895-896.) The discussion that follows is a description of each full and partial retrofit design proposed by Petitioners.

A. Components

1. Cooling Cells

To determine the number of cooling cells, Mr. Powers relied upon the heat input ratings for Units 1 through 4 from the air emissions permit for the Facility. Based on guidance from the US Environmental Protection Agency (EPA), which was referenced in his prefiled testimony,⁷ Mr. Powers calculated the cooling system heat rejection required for Units 1 through 4 to be 44% of the heat input ratings for the four electric generating units. Based on these calculations, Mr. Powers determined that for Units 1 and 2, the cooling system heat rejection requirement is 396 million British thermal units per hour (MMBtu/hr) for each unit. For

⁷ US EPA Technical Development Document (TDD) for the Proposed § 316(b) Phase II Existing Facilities Rule, April 2002, at 5-7. (Tr. 357.)

Unit 3, the cooling system heat rejection requirement is 593 MMBtu/hr, and the cooling system heat rejection requirement for Unit 4 is 1,105 MMBtu/hr. The total heat rejection requirement for Units 1 through 4 is 2,490 MMBtu/hr. The total heat rejection requirement for Units 3 and 4 is 1,698 MMBtu/hr. (Tr. 357.)

According to Mr. Powers, Marley SPX Cooling Technologies, Inc. (Marley) is a leading wet and dry (*i.e.* air cooled condensers [ACCs]) cooling system manufacturer. Mr. Powers identified the plume-abated F488-6.0-6 model (Exhibit 22) as the best combination of performance and size for the Facility. Each F488-6.0-6 cooling cell measures 48 feet long by 48 feet wide by 49 feet high. (Tr. 371.)

To fully retrofit the Facility, Configuration Nos. 1 through 6 would use a total of 14 wet cooling cells grouped into three towers, and located on the areas described below. According to Mr. Powers, Units 1 and 2 would each need two wet cooling cells. Unit 3 would need four wet cells, and Unit 4 would need six wet cells. The design reduces circulating water temperature to within 13°F of wet bulb temperature at rated conditions of 76°F wet bulb temperature and rated load (235 MW). Mr. Powers explained that this temperature is known as the approach temperature. For Unit 3, the approach temperature would be 12°F using four F488-6.0-6 cells. (Tr. 371.)

For Configuration Nos. 7 and 8 described below (see §§ II.C.7 and 8), Mr. Powers proposed to retrofit Unit 3 with a series of ACCs. The dimensions of each ACC would be 44 feet long by 44 feet wide. (Exhibit 19.) Some features of typical ACCs are provided in Exhibit 58. (Tr. 436-437.) To determine the appropriate number of ACCs for Unit 3, Mr. Powers explained that the design objective was to maintain the steam turbine backpressure at less than 5.5 inches of Hg at 90°F. Based on Mr. Powers' analysis, a set of twelve Marley ACCs would meet this design objective. (Tr. 371-372, 744-748.) The proposed orientation and locations of the ACCs for Configuration Nos. 7 and 8 are described in §§ II.C.7 and 8.

With respect to the partial retrofits, Partial Retrofit Configuration Nos. 1 through 3 would use a total of ten wet cooling cells grouped into two towers, and located on the areas described below. Partial Retrofit Configuration No. 4 would consist of a combination of eight wet cooling cells and six ACCs.

2. Cooling Water Return and Discharge Pipes, Intake Basins, and Pumps

Each wet cooling tower would have two pipelines associated with it. The cooling water return pipe extends from the condenser of the individual electric generating unit to the wet cooling tower, and transports heated water from the condenser to the wet cooling tower. As the heated water passes through the wet cooling tower cells, the water cools. The cooled water is collected at the base of the cooling tower and transported via the cooling water discharge pipe to the intake basin. The routes for the cooling water return and the cooling water discharge pipelines depend on the existing infrastructure and proposed location of the cooling cell towers on the site. (Exhibit 19; Tr. 409.)

At present, there is a common intake basin at the end of the intake canal from which each electric generating unit draws its once-through cooling water. (Exhibit 69; Tr. 673-678.) If the Facility is fully retrofitted with a closed-cycle cooling system, Mr. Powers explained how the existing intake basin could be sealed off from the current intake canal,⁸ and reconfigured into four separate intake basins using precast partitions. All electric generating units would need to be offline while the common intake basin is partitioned, which should not take more than a few days, according to Mr. Powers. (Exhibits 19 and 39; Tr. 365-367, 399-400.)

If the Facility is fully retrofitted, each newly created intake basin would receive the cooling water discharge pipe from a particular wet cooling tower. (Tr. 365.) Cooled water from the four newly created intake basins would be recirculated to each of the condensers of the four electric generating units. (Exhibit 19.) Mr. Powers anticipated that the existing pumps could be reused provided they could withstand the higher hydraulic pressure associated with the closed-cycle operation. Nevertheless, the retrofit cost estimates provided by Mr. Powers assume that the pumps would be replaced. (Tr. 367.)

Mr. Powers stated that the size of the cooling water return and the cooling water discharge pipes would depend on the size of the electric generating unit. For Units 1 and 2, the cooling

⁸ For some proposed configurations, the intake canal would be filled in (see e.g. Exhibit 19, Configuration Nos. 1, 6, 7, and 8, as well as Partial Retrofit Configuration No. 1).

water return and discharge pipes would each be 40 inches in diameter for each unit. For Unit 3, the cooling water return and discharge pipes would each be 60 inches in diameter. For Unit 4, the cooling water return and discharge pipes would each be 78 inches in diameter. (Exhibit 19.)

B. Cooling Tower Locations.

Mr. Powers identified seven potential areas on the site to locate closed-cycle cooling towers.⁹ To develop the proposed configurations, Mr. Powers based his designs on a to-scale drawing plan provided to him by Dynegy. Moving clockwise around the site, the first potential area is north of the waste water treatment storage lagoons between the right-of-ways for the CSX railroad and the FAA radio beacon (Area 1). (Exhibits 19 and 45.)

As part of Configuration No. 1, Mr. Powers proposes to place two wet cooling units on a concrete slab without piles. The approximate footprint would be 50 feet by 96 feet. According to Mr. Powers, piles would not be necessary because the associated cold water basin is relatively shallow, the cooling units are relatively light, and their weight would be distributed evenly over a relatively large area. (Tr. 412, 552-553.) Mr. Powers acknowledged that Area 1 is located in the A-3 flood plain, and observed that the powerhouse, the electrical substation, as well as many other features of the Facility are also located in the A-3 flood plain. (Tr. 414.) If it becomes necessary to stabilize the shoreline to use Area 1, Mr. Powers explained that "hard armor" techniques such as low walls, similar to the ones used to construct the intake canal and the discharge tunnel outfalls, or rip-rap could be installed. (Tr. 412-413.)

To assemble the components of the cooling tower on Area 1, Mr. Powers acknowledged that a barge-mounted crane (as suggested by Mr. Micheletti¹⁰ [Tr. 1355-1356]) could be used. Mr. Powers

⁹ Appendix D is a chart based on Exhibit 19 which, for each of the twelve proposed retrofit configurations, identifies the seven areas where towers would be potentially located, the number and type of cooling cells, and the electric generating unit that would be cooled by the proposed towers.

¹⁰ Wayne C. Micheletti testified on behalf of Dynegy. Mr. Micheletti is the founder, owner and president of Wayne C. Micheletti, Inc. (Charlottesville, VA), an engineering

would prefer, however, to transport the cooling tower components by barge, and off-load them with a land-based crane. According to Mr. Powers, this method was used at the Crockett Cogeneration Plant in California. (Exhibit 46; Tr. 413.) Mr. Powers stated there is ample space for a land-based crane to pass through either the FAA beacon easement or the northern edge of the waste water treatment area. (Tr. 413).

According to Mr. Powers, the construction and operation of cooling towers on Area 1 would not encroach on the CSX railroad right-of-way. As a result, Mr. Powers concluded that no approval from CSX would be required to put the proposed cooling tower on Area 1. Mr. Powers stated that the proposed two-cell cooling tower on Area 1 would be no closer to the CSX right-of-way than the existing waste water treatment plant or the active coal pile. (Tr. 416.)

The second potential area is east-southeast of the area reserved for the FAA beacon (Area 2). (Exhibit 19.) Area 2 is also in the A-3 flood plain, and poses no limitation to the construction of cooling towers because the mechanical components are elevated and the base of the cooling tower is essentially a swimming pool, according to Mr. Powers. Area 2 is the site of a decommissioned waste water treatment storage lagoon that is presently covered with scrub forest vegetation. (Exhibit 48; Tr. 417.) Mr. Powers proposes to fill the decommissioned waste water treatment lagoon to grade, and place a four-cell cooling tower on Area 2 as part of Configuration Nos. 1, 2, 5, 6, as well as Partial Retrofit Configuration No. 1. Using this area would require the discharge stream, associated with Outfalls 006, 06A and 019 in the draft SPDES permit, to be relocated around the cooling tower placed on this area. (Exhibit 19; Tr. 368, 433, 1356.)

The third area identified as a potential location for a wet cooling tower is over the intake canal (Area 3). According to Mr. Powers, the intake canal would not be needed if the Facility is fully retrofitted with a closed-cycle cooling system because the amount of water that would be needed to cool the Facility would be substantially reduced, compared to the current once-through system. Any required pipes for the various closed-cycle cooling system configurations that have been proposed could be placed in the decommissioned canal before the canal is backfilled. (Exhibit 19.) Mr. Powers estimates that the volume

consulting firm.

of material that would be excavated for the foundations of the various proposed cooling towers would be approximately equal to the volume of fill needed to fill in the intake canal. (Tr. 364-365.) Subsequently, cooling cells would be placed on this area. Wet cooling cells would be placed on Area 3 as part of Configuration Nos. 1, 6, 7, as well as Partial Retrofit Configuration No. 1. The number of wet cooling cells depends on the details associated with each configuration and varies from two to eight. For Configuration No. 8, six ACCs would be placed on Area 3. (Exhibit 19.)

The fourth potential area is west of the intake canal (Area 4). Presently, a one-story metal warehouse building occupies this area, which would have to be razed before a cooling tower could be placed at this location. (Exhibit 19; Tr. 363, 393, 1356.) Some of the materials stored in this warehouse are associated with the maintenance of the intake canal, the fish screens, and the traveling racks. These materials would no longer be necessary if the Facility is fully retrofitted, according to Mr. Powers. (Tr. 419-420.) A closed cycle cooling tower consisting of four cells, as described above, would be placed on Area 4 as part of Configuration Nos. 2, 3, 4 and 5, as well as Partial Retrofit Configuration Nos. 3 and 4. (Exhibit 19.)

The fifth potential area for a cooling tower is along the eastern wall of the powerhouse (Area 5). Area 5 would be used to locate ACCs (*i.e.* dry cooling towers) as part of Configuration Nos. 7 and 8, as well as Partial Retrofit Configuration No. 4. According to the proposed configurations, the ACCs on Area 5 would be raised 40 feet above grade, which would permit light and medium weight vehicles to pass underneath the cooling units. (Exhibit 19, Configuration 8, at 1 of 3; Tr. 437.) The overall height of the ACCs tower is unknown.

The sixth proposed location is an area south of the powerhouse between the common air emission stack for Units 3 and 4, and the sand filter for the sanitary waste water system (Area 6). To place a cooling tower on Area 6, a portion of the discharge pipe from the sanitary waste water system would have to be relocated. (Exhibit 19; Tr. 368, 433.) Depending on the proposed configuration, four or six wet cooling units would be placed on Area 6 as part of Configuration Nos. 3, 4, 5, 6, 7 and 8, as well as Partial Retrofit Configuration Nos. 2, 3 and 4. (Exhibit 19.)

Dynegy maintains that a cooling tower could not be located on Area 6 for several reasons. Two principal reasons are that the area is presently used as an equipment lay-down area during maintenance events. In addition, the area is the proposed location of a fuel gas desulfurization (FGD) system. The purpose of an FGD system would be to reduce sulfur dioxide (SO₂) emissions. According to Mr. Powers, however, Area 6 would be at least 400 feet from the southern wall of the powerhouse, which would still provide for a lay-down area, space for an FGD system, or both. (Tr. 431.) These issues are discussed in § II.F.

The seventh proposed location is a triangular area west of the right-of-way for the CSX railroad tracks and between the right-of-ways for the overhead transmission lines owned by Central Hudson (115 kV) and NYPA (345 kV) (Area 7). If a cooling tower is placed on Area 7, the proposed cooling tower would be located outside the right-of-ways. (Tr. 369, 1462-1468.) In addition, Mr. Powers stated that the Occupational Safety and Health Administration (OSHA) has issued requirements concerning crane operations in the vicinity of overhead power lines. For safety purposes, minimum distances must be maintained between crane operations and overhead power lines. Given the respective widths of the right-of-ways for the overhead transmission lines in combination with the area where the cooling tower would be placed, Mr. Powers concluded that the OSHA requirements would be met if a crane is used to assemble the cooling tower components in Area 7. (Tr. 429.) Depending on the proposed configuration, four or six wet cooling units would be placed on Area 7 as part of Configuration Nos. 2, 3, 4 and 8, as well as Partial Retrofit Configuration No. 2. (Exhibit 19.)

If a cooling tower is located on Area 7, the cooling water return pipeline from the electric generating units to the cooling tower and the cooling water discharge pipeline from the cooling tower to the intake basin would need to pass under the CSX railroad tracks and cross a natural gas pipeline. (Exhibit 19.) On Exhibit 19, Mr. Powers has proposed three potential routes for the pipelines. Two of the three potential routes may pass through portions of the transmission line right-of-ways. (Tr. 369.) More information about the potential pipeline routes is provided in § II.C.2.

C. Full Retrofits

1. Configuration No. 1

For Configuration No. 1, 14 wet cooling cells (Marley F488-6.0-6) would be grouped into three towers. Two cells, oriented along a north-northeast to south-southwest axis, would be placed on Area 1, which is located near the north shoreline between the right-of-ways for the FAA beacon and the CSX railroad. These two cells would cool either electric generating Unit 1 or Unit 2. From the two-cell cooling tower, a set of 40-inch diameter cooling water return and discharge pipes would be buried in a common trench and oriented either vertically or side-by-side. The pipeline route would pass along the western edge of the waste water treatment facilities, and then along the southern edge of the waste water treatment facilities to the northeast corner of the powerhouse. (Exhibit 19.)

Exhibit 39 provides additional details about how the existing intake basin, first, would be isolated from the intake canal, and then partitioned to create four individual basins to receive the cooling water discharge pipes from the individual cooling cell towers. With respect to the two cell unit located on Area 1, an intake basin to receive the 40-inch diameter cooling water pipes would be built by sealing the existing intake tunnels for Units 1 and 2 in the vicinity of the powerhouse wall, and constructing an internal partition to isolate cooling water flows from Units 1 and 2. (Exhibits 19 and 39; Tr. 407.)

For electric generating Unit 3, a four-cell cooling tower, oriented along a west-northwest to east-southeast axis, would be placed on Area 2, which is a decommissioned waste water treatment storage lagoon. (Exhibit 19.) As previously noted, the discharge stream (Outfall 019) at the northeast corner of the waste water treatment facility would need to be rerouted around this tower. (Tr. 368, 433, 1356.)

From electric generating Unit 3, the trench for the 60-inch diameter cooling water return pipe would follow along the eastern side of the powerhouse, then along the western side of the intake canal, and turn to the left at a 90° angle toward the four-cell cooling tower. The route for the 60-inch diameter cooling water discharge pipe from the four-cell cooling tower would pass along the eastern side of the intake canal to the intake basin. The subsurface conditions of the area along the eastern side of the intake canal are unknown. Mr. Powers requested information about

the subsurface conditions to determine whether blasting would be required to construct the trench for the 60-inch diameter cooling water discharge pipe. (Exhibits 19 and 49; Tr. 417-418.) According to Mr. Micheletti, bedrock in this area would require blasting to excavate the trench for the cooling water discharge pipe line. (Tr. 1357).

For Unit 4, and either Unit 1 or Unit 2, an eight-cell cooling tower would be oriented along a north-northeast to south-southwest axis, and placed over the current site of the intake canal, which is identified as Area 3. In part, the cooling water discharge pipe from Unit 4 would be the current 90-inch diameter return pipe for Units 1 and 2. At a point north of the powerhouse, the 90-inch diameter pipe would be reduced to a 78-inch diameter pipe, and extend to the eight-cell cooling tower. The trench for the 78-inch diameter cooling water discharge pipe from six of the eight-cell cooling tower would be relatively short to the intake basin for Unit 4. (Exhibits 19 and 39.) Details were not provided about how the required 40-inch diameter cooling water return and discharge pipes would be configured vis-a-vis the two remaining cells in the eight-cell tower that would be used to cool either Unit 1 or 2.

2. Configuration No. 2

For Configuration No. 2, 14 wet cooling cells (Marley F488-6.0-6) would be arranged into three towers, and located on Areas 2, 4, and 7. For Units 1 and 2, a single row of four cells would be oriented along a west-northwest to east-southeast axis, and placed on the decommissioned waste water treatment lagoon (Area 2). From the four-cell cooling tower, two sets of 40-inch diameter cooling water return and discharge pipes (one set for each electric generating unit) would be buried in a common trench and oriented either vertically or side-by-side. The proposed pipeline route would follow along the eastern side of the powerhouse, then along the western side of where the cooling tower for Unit 3 would be located, and then turn left toward the four-cell cooling unit. The intake basins associated with Units 1 and 2 would be constructed in the manner described in Configuration No. 1. (Exhibits 19 and 39.)

For Unit 3, a single row of four cells would be oriented along a north-northeast to south-southwest axis, and placed to the west of the intake canal, identified as Area 4, where a one-story metal warehouse building is currently located. According to Mr. Powers, a cooling tower at this location should not

adversely impact the parking spaces currently available near this area. (Tr. 420.)

The initial portion of the cooling water return pipe from Unit 3 would be the current 90-inch diameter discharge pipe for Units 1 and 2, which would subsequently be reduced to a 60-inch diameter pipe and extended to the four-cell cooling tower. The distance from the trench for the 60-inch diameter cooling water discharge pipe from the four-cell cooling tower to the intake basin would be relatively short. (Exhibit 19.) Exhibit 39 provides additional details about how the intake basin for Unit 3 would be configured from the existing intake basin.

The cooling tower for Unit 4 would consist of six cells arranged in a 3x2 configuration, and located on Area 7, which is west of the railroad tracks in a triangular area formed by the railroad right-of-way, and the right-of-ways for the overhead transmission lines. The cooling water return and discharge pipes would be 78-inches in diameter, and would be stacked vertically or placed side-by-side in a common trench using open trench construction. (Exhibit 19.) An intake basin to receive the 78-inch diameter discharge pipe from the cooling cells would be constructed by enclosing the existing area in front of the pumps for Unit 4. (Exhibit 39.)

In Exhibit 19, Mr. Powers proposes three potential routes for the cooling water return and discharge pipelines from Area 7 on the west side of railroad tracks. The potential routes are identified as Alternatives A, B and C on Exhibit 19 (Configuration 2, Units 1-4, at 2 of 2). Alternative A would pass under the railroad tracks just south of the right-of-way for the Central Hudson 115 kV transmission line, and across from the coal unloading building. Alternative B would pass under the railroad tracks just north of the reserve coal pile, and Alternative C would pass under the railroad tracks just south of the reserve coal pile. The preferred trench pathway would be determined by the most advantageous point to tunnel under the railroad right-of-way and the natural gas pipeline. (Exhibit 19.)

Exhibit 38, which is a portion of the 1983 plan view of the Facility, depicts a culvert passing under the railroad tracks. The culvert is about 25 feet wide, and is located south of the reserve coal pile. The culvert was built to accommodate the Roseton-Iroquois gas pipeline. (Tr. 427.) The location of the culvert is in the vicinity of the proposed cooling water pipe route identified as Alternative C on Exhibit 19 (Configuration 2, Units 1-4, at 2 of 2). Mr. Powers stated that from a cost and

engineering standpoint, using the culvert to convey the cooling water return and discharge pipe lines under the railroad tracks makes Alternative C the most attractive route for the required cooling water return and discharge pipelines. The natural gas pipeline is 16 inches in diameter in a 24-inch diameter casing. According to Mr. Powers, there should be sufficient space in the existing culvert for a set of cooling water pipelines. Mr. Power did not review any details about where the gas pipeline passes through the culvert, and acknowledged that additional information about the culvert would need to be reviewed. Mr. Powers stated that the natural gas pipeline may have to be relocated within the culvert in order to accommodate the cooling water pipelines. (Tr. 406, 427-428, 613-615.)

With respect to the Alternative C proposed pipeline route, Mr. Powers explained further that the minimum distance between the edge of the reserve coal pile and the NYPA transmission line right-of-way is 25 feet at the southwest corner of the reserve coal pile. According to Mr. Powers, the maximum trench width including trench shields to accommodate two 78-inch cooling water pipes for Unit 4 would be 20 feet. Mr. Powers estimates, however, that the initial section of the reserve coal pile runoff collector wall is about 15 feet, at its narrowest point, from the right-of-way for the NYPA overhead transmission line. Therefore, to use this proposed alternative pipeline route, Mr. Powers explained that either the first 30 to 40 feet of the reserve coal pile runoff collector would have to be relocated to prevent the trench for the cooling water pipelines from encroaching onto the NYPA right-of-way, or NYPA would have to provide permission to bury the cooling water pipelines in the transmission right-of-way for this approximate distance. (Tr. 428.)

If the 25-foot wide culvert under the CSX railroad tracks will not accommodate the cooling water pipelines, then Mr. Powers has proposed a process called "horizontal" drilling to tunnel under the tracks at the proposed alternative locations. According to Mr. Powers, this process would not disturb the railroad tracks during the excavation of the pipeline trench and tunnel. (Tr. 369.)

The "horizontal" drilling process requires digging a pipe-launch shaft and a receiving shaft. These shafts would be dug on either side of the tracks. According to Mr. Powers, there is adequate space on either side of the railroad right-of-way for these shafts. Mr. Powers explained further that the minimum diameter of the launch shaft would be 26 feet and the diameter of the shaft diameter would be 16 feet. Under these conditions, Mr.

Powers explained that an 84-inch diameter pre-stressed concrete pipe with liner could be placed under the railroad tracks. The 84-inch diameter pre-stressed concrete pipe and liner would be slightly larger than the 78-inch diameter pipes needed for the cooling water return and intake pipes for Unit 4. The geotechnical report reviewed by Mr. Powers shows that the soil depth is 30 feet or more below the railroad tracks at the proposed crossing points. Soil is a favorable medium for tunneling, according to Mr. Powers. (Tr. 369-370, 423.)

If cooling cell units are located on Area 7, west of the railroad tracks, and if the 25-foot wide culvert cannot be used to pass the cooling water return and discharge pipes under the railroad tracks, a natural gas pipeline will also have to be traversed. Mr. Powers explained that standard gas line excavation, cutting, replacement, and testing procedures would be used to traverse the pipeline. Mr. Powers estimated that the gas pipeline would be taken out of service for about one week. (Exhibit 52; Tr. 407.)

3. Configuration No. 3

Configuration No. 3 would consist of 14 wet cooling cells (Marley F488-6.0-6) grouped into three towers on Areas 4, 6 and 7. For Units 1 and 2, a single row of four cells would be located west of the intake canal (Area 4). Two sets of cooling water return and discharge pipes, one set for each electric generating unit, would be buried in a common trench and oriented either vertically or side-by-side. (Exhibit 19.) Details concerning the construction of the intake basins for Units 1 and 2 are presented above as part of the description for Configuration No. 1. (Exhibit 39.)

For Unit 3, a four-cell tower, oriented along a northeast to southwest axis, would be located south of the powerhouse between the common emission stack for Units 3 and 4, and the sand filter for the sanitary waste water system. A cooling water pump would be required on the northern end of the four-cell cooling tower. (Exhibit 19.) This proposed location is identified as Area 6. According to Mr. Powers, the south site is an excellent area for placing a cooling tower and has no fatal flaws associated with it. (Tr. 435).

Two alternative routes for the trench needed to contain the 60-inch diameter cooling water return and discharge pipes have been proposed. One route would pass along the western side of the substation and around the northern side of the powerhouse,

turn south and then proceed along the eastern side of the powerhouse. The other route would go along the east side of the powerhouse. (Exhibit 19.) A portion of the discharge pipe from the sanitary waste water system may have to be relocated to accommodate the cooling tower proposed for this location. (Tr. 368, 433.)

The cooling tower for Unit 4 would consist of six cells arranged in a 3x2 configuration, and located on Area 7, which is west of the railroad tracks. (Exhibit 19.) The discussion related to Configuration No. 2 provides a description of the size of the cooling water return and discharge pipes, the proposed alternative trench pathways, as well as the construction of the intake basin for Unit 4.

4. Configuration No. 4

Configuration No. 4 is similar to Configuration No. 3. As previously described in Configuration No. 3, a four-cell tower would be located on Area 4 for Units 1 and 2. (Exhibit 19.) The details concerning the placement and use of cooling cells at this location for Units 1 and 2 are addressed in § II.C.2.

For Unit 3,¹¹ four cells would be arranged in a single row on a west-northwest to east-southeast axis, and located west of the railroad tracks on Area 7. (Exhibit 19.) Details about the 60-inch diameter cooling water return and discharge pipes, the proposed alternative trench pathways, and construction of the intake basin for Unit 3 would be similar to the features proposed as part of Configuration No. 2.

The cooling tower for Unit 4 would consist of six wet cells arranged in a single row, oriented along a northeast to southwest axis, and located on Area 6. (Exhibit 56.) This area is between the access road and the river bank. Mr. Powers explained that

¹¹ The caption boxes on page 2 of 3 for Configuration 4 (Exhibit 19) provide details for the retrofit of Units 1 and 2. Based on a review of the entire proposed configuration, however, it appears that the caption boxes on page 2 of 3 for Configuration No. 4 actually relate to Unit 3. The basis for this determination is as follows. First, page 1 of 3 provides a description for the retrofit of Units 1 and 2. Second, Mr. Powers testified that Unit 3 would require four cooling cells (Tr. 371), which are proposed on page 2 of 3.

six wet cooling cells at this location¹² would not abut the small hill across the access road to the west. At its closest point, the proposed cooling tower would be about 40 feet from the base of the hill and about 20 feet from the shoreline. Mr. Powers stated that the design for this set of cooling cells would ensure the continued use of the access road. (Exhibit 56, Tr. 434-435.) According to Mr. Powers, an area of 150 feet by 200 feet would remain available south of the powerhouse to use as a lay-down area. (Tr. 435.)

5. Configuration No. 5

Configuration No. 5 would consist of 14 wet cooling cells (Marley F488-6.0-6), grouped into three towers on Areas 2, 4, and 6. (Exhibit 19.) For Units 1 and 2, a single row of four cells would be placed on Area 2, which is the decommissioned waste water treatment storage lagoon. For electric generating Unit 3, a single row of four wet cells would be placed west of the intake canal, which is Area 4. The six-cell cooling tower for Unit 4 would be placed on Area 6, which is south of the powerhouse. Details about the cooling water return and discharge pipes, the proposed trench pathways, and the construction of the intake basins for the individual electric generating units are discussed in §§ II.C.1 and 3.

6. Configuration No. 6

Configuration No. 6 would place wet cooling towers on Areas 2, 3 and 6. (Exhibit 19.) For Units 1 and 2, a single row of four cells would be placed on Area 2, which is over the decommissioned waste water treatment storage lagoon. For Unit 3, four cells would be arranged in a single row and located south of the powerhouse on Area 6. For electric generating Unit 4, a single row of six cells would be placed over the current site of the intake canal, which is Area 3. Details about the cooling water return and discharge pipes, the proposed trench pathways, and the construction of the intake basins for the individual electric generating units are discussed in §§ II.C.1 and 3.

¹² At this location (Area 6), a four-cell wet cooling tower has been proposed for electric generating Unit 3 in Configuration Nos. 3 and 6.

7. Configuration No. 7

Configuration No. 7 would consist of a combination of 12 wet cooling cells and 6 ACCs. A single row of six wet cells would be placed over the current site of the intake canal, which is Area 3. Four of the six wet cells would cool Units 1 and 2, and the remaining two wet cells would be used in combination with six ACCs to cool Unit 3. (Exhibit 19.)

For Unit 3, the two wet cells identified above would be connected in parallel to a single row of six ACCs, and placed along the east wall of the powerhouse (Area 5). (Exhibit 19.) If retrofitted with ACCs, the existing surface condenser for Unit 3 can be reused, according to Mr. Powers. The internal components, however, would be removed, and the condenser shell would serve as the plenum for the 12-foot diameter main ACCs steam duct. A round to square duct transition may be necessary to interconnect the duct to the east wall of the surface condenser. Mr. Powers stated further that the supporting infrastructure for the steam turbine would not be disturbed as part of this retrofit. In the powerhouse, a number of small pumps and a small office may need to be relocated to accommodate the main steam duct. According to Mr. Powers, the open areas in front of the north and south walls of the Unit 3 surface condenser are good alternative locations for the components that would need to be moved. Mr. Powers stated that much of the overhead piping that could potentially obstruct the passage of the main steam duct to the surface condenser wall appears to be decommissioned. (Exhibit 30; Tr. 370-371, 397, 436, 1356-1366.)

Mr. Powers explained further that a convenient location for the 12-foot diameter main steam duct would be on the powerhouse roof immediately adjacent to the ACCs. At this proposed location, the 12-foot main steam duct would not be a ground level obstacle. An alternative location would be to elevate the main steam duct to the same height as the ACCs, and then lower the main steam duct to ground level at the point where it would enter the powerhouse. (Tr. 437-438.)

The cooling tower for Unit 4 would consist of six cells located south of the powerhouse on Area 6. (Exhibit 19.) Details about the 78-inch diameter cooling water return and discharge pipes, the proposed alternative trench pathways, and the construction of the intake basin for Unit 4 are discussed in § II.C.2.

8. Configuration No. 8

Configuration No. 8 would consist of a combination of ten wet cooling cells and 12 ACCs. Units 1 and 2 would be cooled with a set of four wet cells placed on Area 7, west of the railroad tracks. Unit 4 would be cooled with a set of six wet cells placed on Area 6, which is south of the powerhouse. (Exhibit 19.) Details about the cooling water return and discharge pipes, the proposed trench pathways from Areas 6 and 7, and the construction of the intake basins for Units 1, 2 and 4 are discussed in §§ II.C.2 and 3.

Unit 3 would be cooled using two sets of ACCs placed on Areas 3 and 5. The first set would be a single row of six cells, placed over the current site of the intake canal (Area 3). The second set would be another row of six dry cooling cells placed along the east wall of the powerhouse (Area 5). Along the southeast wall of the surface condenser for Unit 3, a 9-foot by 12-foot duct would interconnect with the shell of the surface condenser, as described in Configuration No. 7. From Unit 3, the 9-foot by 12-foot duct would transition to a round 12-foot diameter duct. At the ACC tower, the round 12-foot diameter duct would split into two round 8.5-foot diameter ducts and connect to each set of six ACCs. As noted in Configuration No. 7, two service water pumps, two bearing water pumps and potentially the foreman's office in the powerhouse may need to be relocated to accommodate the duct work. (Exhibits 19 and 30.)

D. Partial Retrofits

Petitioners proposed four partial retrofit configurations. For each partial retrofit, Units 3 and 4 would be converted from a once-through cooling system to a closed-cycle cooling system. Units 1 and 2 would not be converted and would retain their once-through cooling system configurations. Compared to Units 1 and 2, Units 3 and 4 are larger units, operate more frequently, and require more cooling water. With respect to the proposed partial retrofit configurations, the areas where cooling units would be placed are the same as for the proposed full retrofit configurations.

Exhibit 31 is a diagram that shows how the common intake basin would be reconfigured to permit Units 1 and 2 to withdraw water from the river on a continuous basis for once-through cooling purposes while providing a common closed-cycle cooling water intake basin for Units 3 and 4. The current intake basin would be partitioned from the intake canal, which would be filled

in. For Unit 4, partial Retrofit Configuration No. 1 would place six wet cooling units on the area of the filled-in canal (Area 3). Another partition would separate Units 1 and 2 from Units 3 and 4. This partition, however, would have a hole through which a round pipe or square channel with an equivalent diameter of at least 60 inches would be installed that would interconnect the intake basin for Units 1 and 2 with the Hudson River via the existing auxiliary (or emergency) intake. Cooling water discharge pipes from the closed-cycle cooling towers would be connected to the common intake basin for Units 3 and 4, and cooling water would recirculate through the intake basin to these two electric generating units. (Tr. 366.)

1. Partial Retrofit Configuration No. 1

Partial Retrofit Configuration No. 1 would consist of ten wet cooling cells grouped into two towers. For Unit 3, a single row of four cells would be placed over a decommissioned waste water treatment storage lagoon (Area 2). For Unit 4, a single row of six cells would be placed over the current site of the intake canal, which is Area 3. (Exhibit 19.) Details about the cooling water return and discharge pipes, and the proposed trench pathways from Areas 2 and 3 are presented in § II.C.1.

2. Partial Retrofit Configuration No. 2

The same number and type of wet cooling cells that would be used in Partial Retrofit Configuration No. 1 would also be used in Partial Retrofit Configuration No. 2, but the cells would be placed on different areas. For Unit 3, four cells would be arranged in a single row and placed on Area 7, which is west of the railroad tracks. For Unit 4, six cells arranged in a single row would be located south of the powerhouse on Area 6. (Exhibit 19.) Details about the cooling water return and discharge pipes, and the proposed trench pathways from Areas 6 and 7 are outlined in §§ II.C.2 and 3.

3. Partial Retrofit Configuration No. 3

Partial Retrofit Configuration No. 3 would consist of ten wet cooling cells grouped into two towers. For Unit 3, a single row of four cells would be placed to the west of the intake canal on Area 4. For electric generating Unit 4, six cells arranged in a single row, would be located south of the powerhouse on Area 6. (Exhibit 19.) Details about the cooling water return and discharge pipes, and the proposed trench pathways from Areas 4 and 6 are discussed above in §§ II.C.2 and 3.

4. Partial Retrofit Configuration No. 4

Partial Retrofit Configuration No. 4 would consist of a combination of eight wet and six ACCs. For Unit 3, two of the eight wet cells would be placed on the western side of the intake canal (Area 4). In addition, Unit 3 would be connected in parallel with a single row of six ACCs placed along the east wall of the powerhouse (Area 5). A steam duct (8.5 ft diameter) would connect Unit 3 to the six dry cells. To accommodate the steam duct, service water pumps, bearing water pumps and, potentially, the foreman's office in the powerhouse may need to be relocated. (Exhibit 19.)

The cooling tower for Unit 4 would consist of six wet cells located south of the powerhouse on Area 6. Details about the cooling water return and discharge pipes, and the proposed trench pathways from Areas 4 and 6 are outlined in §§ II.C.2 and 3. (Exhibit 19.)

E. Cooling Tower Size - Unit 4

1. Petitioners' Proposed Cooling Tower Design

Mr. Powers stated that the thermal performance of Facility's current once-through cooling system served as the basis for the design of the proposed closed-cycle cooling system retrofit configurations. (Tr. 478.) Mr. Powers, however, identified three factors that limited the design of the proposed retrofit configurations. The principal factor is the amount of space on which to locate the cooling towers for the four electric generating units. The two remaining factors are costs, and the climatic conditions, which directly affect the thermal performance of the proposed retrofit cooling system. (Tr. 903-904.) According to Mr. Powers, a point is reached when additional capital investment in equipment and the associated energy costs outweigh any additional efficiency. (Tr. 912.) Mr. Powers concluded that optimizing the design of the proposed retrofit configurations to meet the thermal performance level of the current once-through cooling system should be a goal or target, rather than an absolute requirement (Tr. 479, 725), and he designed the proposed retrofit configurations accordingly.

Mr. Powers identified the Palomar Energy Project (PEP) in southern California as a facility comparable to Unit 4 at the Facility. PEP, which at the time of the hearing was under construction, would generate 229 MW, and the design wet bulb

temperature for the closed-cycle wet cooling system is 77°F.¹³ The plume abated closed-cycle cooling tower at PEP would consist of seven cells to meet a design heat rejection rate of 1,250 MMBtu/hr. The dimensions of the cooling tower for PEP would be 384 feet long by 54 feet wide and 65 feet high. (Tr. 360.) With respect to the PEP facility, Mr. Powers did not identify the cooling tower manufacturer, provide the model number of the cooling cells, or explain whether any features of the cooling cells were either modified or augmented to improve their thermal performance.

To design the closed-cycle cooling tower for Unit 4, Mr. Powers reviewed the specifications for two different plume abated, wet cooling cell models manufactured by Marley, which are identified by model numbers F488 and F489. The dimensions of the Marley F488 cell are 48 feet long by 48 feet wide by 49 feet high. The dimensions of the Marley F489 cell are 54 feet long by 48 feet wide by 49 feet high. (Tr. 371, 538, 937, 1408.)

Mr. Powers explained that the Marley F489 had desirable thermal performance qualities, but the required number of cells would be too large given the spatial constraints of the site. (Tr. 937.) Six Marley F489 cells at 54 feet each would result in a cooling tower length of 324 feet (6 cells x 54 feet = 324 feet). Though shorter in length, the Marley F488 cell would not provide a sufficient heat rejection rate. (Tr. 937.) After conferring with the manufacturer, Mr. Powers explained that the thermal performance qualities of the Marley F488 cell could be improved by adding six feet of film fill material and by increasing the number of blades on the exhaust fan for each cell. (Tr. 922, 938.) With these modifications, the Marley F488 cell would match the thermal performance qualities of the Marley F489 cell without the added length associated with the Marley F489 cell, according to Mr. Powers. (Tr. 938, 946-947.)

As a result, Mr. Powers has proposed six Marley F488 with additional components, as described in the preceding paragraph, to retrofit the cooling system for electric generating Unit 4. The dimensions of each cell would be 48 feet long by 48 feet wide by 49 feet high. Therefore, the cooling tower for Unit 4 would be 288 feet long (6 x 48 = 288) by 48 feet wide, which would

¹³ Additional design details for the PEP project are provided in footnote 3 at 6 of Mr. Powers' direct testimony. Unit 4 generates 235 MW and the design wet bulb temperature for Newburgh, New York is 76°F. (Tr. 357, 360.)

occupy an approximate area of 13,824 square feet. (Tr. 371, 1409.)

2. Dynegy's Proposed Cooling Tower Design

Dynegy offered the expert testimony of a panel of witnesses to address the physical feasibility of retrofitting the Facility with the various closed-cycle cooling system configurations proposed by Petitioners. The panel members were Martin W. Daley, Michael C. Ascenzi, P.E., Wayne C. Micheletti, David B. Grogan, and Matthew W. Allen. Mr. Daley is the Senior Director of Regulatory Affairs and Administrative Services with Dynegy Northeast Generation, Inc. (Exhibit 109; Tr. 1328.) Mr. Ascenzi is a registered professional engineer in New York State, and serves as the Director of Engineering at the Danskammer Generating Station. (Exhibit 110; Tr. 1328.) Mr. Micheletti is the founder, owner and president of Wayne C. Micheletti, Inc. (Charlottesville, VA), an engineering consulting firm. (Exhibit 107; Tr. 1328.) Mr. Grogan is the Managing Principal of DB Grogan Associates, LLC (Gloucester, MA), an engineering consultant firm. (Exhibit 108; Tr. 1328.) Mr. Allen is an Associate Principal with Saratoga Associates, Landscape Architects, Architects, Engineers and Planners, PC (Saratoga Springs, NY). (Exhibit 113; Tr. 1384.)

Although the panelists identified many concerns about retrofitting the Facility with a closed-cycle cooling system, the principal concern was whether the proposed closed-cycle cooling tower for Unit 4 was properly sized. According to Messrs. Grogan and Micheletti, the proposed retrofit is undersized. (Tr. 1406.) The dispute centers around whether the thermal performance of the proposed closed-cycle cooling tower for Unit 4 would adequately match that of the Facility's once-through cooling system.

Units 1, 2, 3 and 4, use single-cycle steam-driven turbines to generate electricity. For each electric generating unit at the Facility, process water is heated and the resulting steam is directed to the turbine. As the steam passes over the turbine blades, the turbine spins to operate the electric generator. The steam is then directed to the condenser, where the heat from the steam is transferred to the non-contact cooling water from the Hudson River. The heated non-contact cooling water is discharged to the Hudson River. Meanwhile, the steam from the turbine condenses, and the cooled process water recirculates to the boiler where it is reheated and converted to steam. The cycle repeats.

As the steam cools in the condenser, the pressure at the turbine outlet decreases, which results in a slight vacuum. The change in pressure is called the turbine backpressure. The reduction in pressure increases power generation efficiency. Generally, a steam-turbine generator can operate over a modest range of backpressures; however, each turbine model has an unique design point for optimum efficiency. Operating a turbine at backpressures greater than its design point reduces its electric generating efficiency. Therefore, the efficiency of a particular electric generating turbine directly depends on the effectiveness of the cooling system associated with it. (Exhibit 23, at 1.) For Units 3 and 4, the turbine backpressure design points are, respectively, 1.0 inch of Hg and 1.5 inches of Hg. (Tr. 1406, 1749, [Dec. 19] 2992.)

Because the turbine backpressure design points for Units 3 and 4 are 1.0 and 1.5 inches of Hg, respectively, Messrs. Grogan and Micheletti disagree with Mr. Powers' opinion that little additional benefit would be gained from designing closed-cycle cooling retrofits that would lower the turbine backpressure for Units 3 and 4 below 2.0 to 2.5 inches of Hg. (Tr. 356-357, 1406.) According to Mr. Grogan, most electric generating units located in the northeastern United States with once-through cooling systems have turbine backpressure design points of 1.5 inches of Hg or less. Mr. Micheletti attributes this design criterion to low river water temperatures, which have been traditional sources of cooling water, and acknowledges that newer turbines cooled with recirculating systems have higher turbine backpressure design points in the range identified by Mr. Powers. (Tr. 1406-1407.)

To verify whether the proposed cooling tower retrofit for Unit 4 was properly sized, Mr. Grogan consulted the on-line computer program available on the Marley website. (Tr. 1407.) Mr. Grogan compared the Btu/hour for the heat rejection rate for the PEP cooling tower with the rate from the proposed cooling tower for Unit 4. The heat rejection rate for PEP would be 1,250 MMBtu/hr, and the heat rejection rate to the proposed closed-cycle cooling tower for Unit 4 would be 1,105 MMBtu/hr. (Tr. 1408.) Mr. Grogan also reviewed the dimensions of the cooling towers for PEP and Unit 4, and compared the areas of the two cooling towers. For the PEP cooling tower, the area is about 20,736 square feet. (Tr. 1409.) As noted above, Unit 4 cooling tower would be 288 feet long (6 cells x 48 feet long = 288 feet) by 48 feet wide (Tr. 371, 1408), which is 13,824 square feet. (Tr. 1409.)

Based on these calculations, Mr. Grogan observed that the heat rejection rate for the PEP cooling tower would be 11.6% greater than the heat rejection rate for the proposed cooling tower for Unit 4, but the area of cooling tower for PEP is about 33% larger than the area of the proposed cooling tower for Unit 4. (Tr. 1408, 1410.) This comparison does not account for the difference in the height of the two different cooling towers, which for PEP is 65 feet, and for Unit 4 would be 49 feet.

At the Marley website, Mr. Grogan found there were several F488 cooling tower variations. According to Mr. Grogan, several parameters are critical to designing a retrofit closed cooling system that would be compatible with the turbine backpressure design point for a particular turbine model. The primary parameters are selecting water and steam temperatures that reflect the current operating conditions to ensure an acceptable level of plant efficiency under all seasonal and load fluctuations. (Tr. 1410, [Dec. 19] 2990.)

As part of his direct testimony, Mr. Powers presented an estimate of the turbine back pressure for Unit 4 retrofitted with a closed-cycle cooling system at peak summertime conditions. In this analysis, Mr. Powers assumed a wet bulb temperature of 76°F, a hot cooling water temperature of 109°F, and a saturated steam temperature of 117°F, based on a terminal temperature difference (TTD) of 8°F.¹⁴ The approach temperature for this estimate was 13°F.¹⁵ Under these conditions, the turbine backpressure would be 3.2 inches of Hg. (Exhibit 22, § B.1, at 2 of 5.) Mr. Powers chose the 13°F approach temperature based on his experience with merchant plants, which typically have approach temperatures that range from 12 to 13°F. (Tr. 906.) He considered the 13°F approach temperature to be "a prudent and appropriate balance of cost and efficiency." (Tr. 907.) To further support his choice

¹⁴ The terminal temperature difference (TTD) is the difference between the temperature of the steam entering the condenser and the temperature of the hot water leaving the condenser. (Exhibit 23, at 6; Tr. 633-634.)

¹⁵ The approach temperature is the difference between the temperature of the cold water leaving the cooling tower and the temperature of the inlet air wet-bulb temperature. (Exhibit 23, at 7.) Cooling towers are designed to meet a minimum approach temperature. The temperature of the cold water leaving the cooling tower can never be lower than the inlet air wet-bulb temperature. (Exhibit 23, at 7.)

of a 13°F approach temperature for the cooling tower for Unit 4, Mr. Powers stated that Entergy approved an approach temperature of 15°F for the Indian Point facility.¹⁶ (Tr. 907.)

With his rebuttal testimony, Mr. Powers presented a revised estimate of the turbine backpressure for Unit 4 retrofitted with a closed-cycle cooling system at peak summertime conditions. In the revision, Mr. Powers assumed a wet bulb temperature of 76°F, and a hot cooling water temperature of 109°F. Mr. Powers reduced the saturated steam temperature to 115°F, based on a TTD of 6°F. The approach temperature for the revision remained 13°F. Under these conditions, the turbine backpressure would be 3.0 inches of Hg. (Exhibit 28, § B.1, at 2 of 4; Tr. 620.) In the revised estimate of the turbine back pressure at peak summertime conditions, Mr. Powers lowered the TTD from 8°F in the initial estimate to 6°F. (Tr. 633-634, 735.) Mr. Powers relied on the discussion in Exhibit 23¹⁷ as the basis for reducing the TTD from 8°F to 6°F. (Tr. 622.)

Mr. Grogan opined that the proposed cooling tower retrofit for Unit 4 would not provide adequate cooling capacity. The basis for Mr. Grogan's opinion is that the estimated steam turbine backpressure on Unit 4 retrofitted with the proposed wet cooling tower at peak summer conditions would be either 3.2 inches of Hg (Exhibit 22, § B.1, at 2 of 5) or 3.0 inches of Hg.

¹⁶ The record of this proceeding includes no information about the turbines installed at the Indian Point facility. Consequently, such comparisons have no probative value here.

¹⁷ Exhibit 23 is an article entitled, Emerging Issues and Needs in Power Plant Cooling Systems, by Wayne C. Micheletti and John M. Burns, P.E. According to Mr. Powers, this article was presented at the *Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures*. US EPA sponsored the symposium in May 2003 in Arlington, Virginia. Exhibit 23 was introduced with Mr. Powers' rebuttal testimony, and was initially identified as WP-6. (Tr. 258.) At the hearing, Mr. Micheletti explained that this paper, which he co-authored, addressed national, rather than site specific, issues. Mr. Micheletti stated that in the United States there is a wide range of turbines used in power plants. He stated further that, for Unit 4, the turbine backpressure design point is 1.5 inches of Hg, and for Unit 3, the turbine backpressure design point is 1.0 inches of Hg. (Tr. 1749.)

(Exhibit 28, § B.1, at 2 of 4.) According to Mr. Grogan, operating data showed that under peak summer conditions with the current once-through cooling system, the steam turbine back pressure for Unit 4 actually ranged from 1.3 to 1.5 inches of Hg. (Tr. 1411.) As noted above, the turbine backpressure design point for Unit 4 is 1.5 inches of Hg.

In an attempt to reduce the estimated steam turbine backpressure presented in Exhibit 22 (§ B.1, at 2 of 5), Mr. Grogan evaluated alternative configurations using the on-line program available on the Marley website. As part of the evaluation, Mr. Grogan reduced the approach temperature from 13°F to 8°F. Mr. Grogan kept, as constant, the heat inputs, flows, and design wet bulb temperature. (Tr. 1411-1412.) According to Mr. Grogan, the on-line Marley program recommended eight Marley F489 cooling cells, rather than the six Marley F488 cooling cells proposed by Mr. Powers. (Tr. [Dec. 19] 2990.) Based on the design changes described above, the estimated steam turbine backpressure at peak summertime conditions would change from 3.0 inches of Hg (Exhibit 28, § B.1, at 2 of 4) to 2.6 inches of Hg (Exhibits 197 and 198, § B.1, at 2). (Tr. [Dec. 19] 2986.) With these design changes, the average steam turbine backpressure for June through October would decrease slightly (Exhibits 197 and 198, § B.2, at 2; Tr. [Dec. 19] 2987) from the estimates calculated by Mr. Powers (Exhibit 22, § B.2, at 2 of 5 and Exhibit 28, § B.2, at 2 of 4).

Mr. Grogan explained further that the revised cooling tower design would have four feet of film fill, which is more common than the six feet of film fill recommended by Mr. Powers (Tr. [Dec. 19] 2993.) Mr. Micheletti stated that film fill can improve the thermal efficiency of individual cooling cells, but cautioned that film fill can foul when it becomes plugged. According to Mr. Micheletti, plugging normally occurs in the center of the film fill. When film fill becomes plugged, there can be a substantial loss of thermal efficiency. In addition, Mr. Micheletti stated that instances have been reported where the fill has collapsed into the collection basin. (Tr. [Dec. 19] 3000-3002.) If the depth of the film fill is shorter, then it is easier to clean, according to Mr. Micheletti. (Tr. [Dec. 19] 2995-2996.)

As a result of Mr. Grogan's analysis, the length of the alternative cooling tower for Unit 4 would increase from 288 feet (6 cells x 48 feet long = 288 feet) to more than 380 feet (compare 8 cells x 48 feet long [Marley F488] = 384 feet, with 8 cells x 54 feet long [Marley F489] = 432 feet). Mr. Grogan

stated that the alternative, longer cooling tower demonstrates that Petitioners' proposed retrofit design for Unit 4 is undersized. In addition, Mr. Grogan noted that the proposed undersized cooling tower designed by Mr. Powers would adversely impact the reliability of Unit 4. By considering only the difference in the number of cooling cells, Mr. Grogan explained that Unit 4 could avoid being taken offline if one of eight cooling cells (rather than one of six cells) needed to be shut down for maintenance or repairs. (Tr. [Dec. 19] 2993 and 3112.)

Mr. Powers acknowledged that a closed-cycle cooling tower retrofit for Unit 4 designed with an approach temperature of 13°F would result in a higher turbine backpressure compared to a retrofit cooling tower designed with a lower approach temperature. (Tr. 621.) Mr. Powers also acknowledged that the resulting higher turbine backpressure would reduce the efficiency of the electric turbine generation unit, which in turn would increase fuel consumption and the resulting net air emissions. (Tr. 624.) Mr. Powers maintained, however, that an approach temperature of 8°F, advocated in Mr. Micheletti's article (Exhibit 23, at 7), is a very conservative design criterion. (Tr. 624.) Mr. Powers, nevertheless, agreed that designing a closed-cycle cooling tower retrofit for Unit 4 with an approach temperature of 8°F would require a longer tower than the retrofit he has proposed. (Tr. 627.)

3. Findings

The detailed record of this proceeding, as summarized above, illustrates the challenge of balancing the factors associated with retrofitting the Facility with a closed-cycle cooling system. Though attempting to address the spatial constraints of the site, I find that the proposed closed-cycle cooling tower for Unit 4, which would consist of six Marley F488 cells with six feet of film fill and an approach temperature of 13°F, would be significantly undersized. I find further that the proposed retrofit would routinely contribute to excessively high turbine backpressures that would not adequately meet the original design standards for the Unit 4 steam-driven turbine. If retrofitted as proposed by Petitioners, the resulting operating conditions would be unacceptable from a system performance perspective and, over time, could damage the Unit 4 steam-driven turbine.

I assign significant weight to the expert testimony offered by Messrs. Grogan and Micheletti as the basis for the findings presented in the preceding paragraph. Mr. Grogan has extensive experience designing and evaluating cooling systems for electric

generating facilities, in general. In particular, Mr. Grogan has evaluated the use of variable speed pumps and their anticipated effects on the total performance of the Facility. (Tr. [Dec. 19] 2957.) Such an evaluation reflects Mr. Grogan's familiarity with the Facility and the details of its operations. In addition, Mr. Micheletti has similar, extensive experience with designing and evaluating cooling systems for electric generating facilities. (Tr. [Dec. 19] 2963.)

By his own admission, Mr. Powers did not select the Marley F489 cooling cell, in part, because the resulting tower, which would consist of six cells, would not fit on the site. (Tr. 937.) Furthermore, the design for the proposed retrofit closed-cycle cooling tower presented in this proceeding assumes, without adequate explanation, that the Unit 4 steam-driven turbine could easily adopt to the additional mechanical stress associated with elevated turbine backpressures that would routinely exceed the original design point. Therefore, I conclude that the proposed retrofit design is not based on good engineering practices, and reject it.

The resulting significant design flaw with respect to retrofitting Unit 4 with a closed-cycle cooling tower removes from consideration proposed Configuration Nos. 1, 4, 5, 6, 7 and 8, as well as Partial Retrofit Configuration Nos. 1, 2, 3, and 4 as potentially available with respect to the best technology available determination.

F. Flue Gas Desulfurization (FGD)

1. Net Increase in Emissions

Mr. Powers has proposed to place a cooling tower on an area south of the powerhouse between the common air emissions stack for Units 3 and 4, and the sand filter for the sanitary waste water system. This location has been identified as Area 6 in the discussion related to the proposed closed-cycle cooling retrofit configurations. Depending on the proposed configuration, a cooling tower would be placed on Area 6 as part of Configuration Nos. 3, 4, 5, 6, 7 and 8, as well as Partial Retrofit Configuration Nos. 2, 3 and 4. (Exhibit 19.) Dynegy maintains, however, that a cooling tower could not be located on Area 6 due to the potential need to install an FGD system. (Tr. 1362-1363.)

The proposed retrofits include replacing the heat exchange tubes in the condensers, which Mr. Powers maintains would improve the efficiency of the electric generating units. According to

Mr. Daley, replacing the condensers could subject the Facility to additional requirements of the federal Clean Air Act, such as Prevention of Significant Deterioration (PSD) and New Source Review (NSR). (Tr. 1404.) If, as a result of the retrofit, the net emissions of SO₂ increase by more than 40 tons per year, Dynegy would have to install the best available control technology (BACT) to reduce the net emission increase.¹⁸ For a coal fired electric generating facility, Mr. Daley stated that BACT to reduce SO₂ emissions would be an FGD system. (Tr. [Dec. 19] 3010.) According to Mr. Daley, using lower sulfur coal at the Facility would not control SO₂ emissions sufficiently to obviate the need to install an FGD system. (Tr. [Dec. 19] 3013-3014.)

Mr. Daley stated that the components associated with an FGD system would occupy a considerable area on the site, and that the components would need to be located adjacent to the Facility's existing flue gas duct-work for Units 3 and 4. According to Mr. Daley, the FGD system, if needed, would occupy or encroach upon the location south of the plant that Mr. Powers has identified for cooling towers (*i.e.* Area 6). Mr. Daley estimated that an FGD system for Units 3 and 4 would cost \$63.6 million. (Tr. 1405.) Mr. Ascenzi shared Mr. Daley's opinion with respect to the potential need for, and the location of, the FGD system. (Tr. 1363.)

Mr. Powers tested Dynegy's claim that retrofitting the Facility, either in whole or in part, with a closed-cycle cooling system would require Dynegy to install an FGD system, and other pollution control equipment. In Exhibits 22, and 28, Mr. Powers evaluated the anticipated changes in the operating efficiencies associated with retrofitting Unit 4 with a closed-cycle cooling system. In Exhibit 82, Mr. Powers undertook calculations to determine whether the proposed retrofits would result in a net increase in SO₂ emissions above the annual PSD threshold limit of 40 tons.¹⁹

¹⁸ The PSD threshold limit for SO₂ is 40 tons per year, and the threshold for NO_x is 40 tons per year (40 CFR 52.21).

¹⁹ Exhibit 22 is entitled, *Closed-Cycle Impact on Efficiency, Parasitic Load, Operations and Maintenance, Hydraulic Friction Loss*. In Mr. Powers' prefiled direct testimony, Exhibit 22 was identified as WP-5. (Tr. 376.) Exhibit 28 is entitled, *Refined Calculations on Closed-Cycle Conversion Effect on Steam Cycle Thermal Efficiency*, and was submitted

There is no dispute that the proposed retrofit of Unit 4 with a closed-cycle cooling system will change its efficiency. Changes in efficiency will in turn change the parasitic load. Parasitic load is a percentage of the total amount of electricity produced by Unit 4 that is required to operate equipment associated with electricity production. For example, the water pumps associated with the once-through cooling system for Unit 4 require electricity to operate and contribute to the parasitic load. In Exhibit 22 (§ C, at 3 of 5), Mr. Powers estimated that the parasitic load attributed to the water pumps for the once-through cooling system is 2.0 MW.

Mr. Powers recognized that the parasitic load would change if Unit 4 is retrofitted with a closed-cycle cooling system. Mr. Powers estimated that the parasitic load attributed to the water pumps would increase from 2.0 MW to 3.0 MW, and that the additional load related to the cooling tower fans would be 1.1 MW. An additional factor that would effect the parasitic load is the condenser. According to Mr. Powers, upgrading the condenser would improve the overall efficiency of Unit 4 and, thereby, reduce the parasitic load by 1.2 MW. In Exhibit 22 (§ C, at 3 of 5), Mr. Powers estimated that the total parasitic load associated with the proposed retrofit of Unit 4 would be 2.9 MW (3.0 MW - 1.2 MW + 1.1 MW = 2.9 MW). As a result, the net increase in parasitic load resulting from the proposed retrofit would be 0.9 MW (2.9 MW - 2.0 MW = 0.9 MW), which would increase the parasitic load by 0.4% ($0.9 \text{ MW} / 235 \text{ MW}^{20} = 0.4\%$), according to Mr. Powers (Exhibit 22, § C, at 3 of 5; Tr. 1234).

In Exhibit 82, Mr. Powers presented the calculations he relied on to determine whether the increase in the parasitic load associated with the proposed retrofit would increase net air emissions above the annual PSD threshold limits. If the proposed retrofit would increase the net emissions of SO₂ by more than 40

with Mr. Powers' prefiled rebuttal testimony as WP-11. (Tr. 396.) Exhibit 82 is entitled, *PSD/NSR/NSPS Air Emission Increase Significance Levels and Estimated Emissions Increase from Closed-Cycle Retrofit*, and dated November 15, 2005. (Tr. 971-972.) The analyses presented in Exhibits 22, 28 and 82 relate specifically to Unit 4, which has an electric generating capacity of 235 megawatts.

²⁰ The electric generating capacity of Unit 4 is 235 megawatts.

tons per year, then Dynegy would need to install additional pollution control equipment, such as an FGD system.

According to Mr. Powers, SO₂ emissions from the Facility are 1.1 lbs/MMBtu, which he converted to an annual emission rate of 15,318 tons. (Exhibit 82, § II.) In Section III of Exhibit 82, Mr. Powers calculated the incremental net increase in air emissions from the Facility based on the change in efficiency, which Mr. Powers initially estimated was 0.1%. Mr. Powers determined that the net increase in SO₂ emissions would be approximately 15.3 tons per year (Exhibit 82, § III), which is less than the annual PSD threshold limit of 40 tons. At that time, Mr. Powers concluded that the Facility would not need an FGD system.

Subsequently, Mr. Powers discovered that his reliance on a 0.1% change in efficiency was incorrect. According to Mr. Powers, the correct change in efficiency associated with the proposed retrofit would be 0.6%.²¹ (Tr. 1235-1241.) Consequently, Mr. Powers revised his calculations, which showed that the expected net increase in SO₂ emissions would be about 92 tons per year. (Tr. 1241.) Emissions of NO_x and PM₁₀ would also increase more than initially estimated. (Tr. 1243.) Based on these revisions, Mr. Powers acknowledged that retrofitting the Facility's cooling system would require Dynegy to install additional air pollution control equipment, such as an FGD system, to reduce the anticipated net increase in SO₂ emissions. (Tr. 1242, 1244).

Mr. Grogan evaluated Mr. Powers' analyses, and concluded that the analyses had significantly underestimated the potential effects. Mr. Grogan presented revised calculations in Exhibits 196, 197 and 198.²² (Tr. [Dec. 19] 2974-2975.) According to Mr. Grogan, the actual parasitic load for the pumps associated with

²¹ Mr. Powers did not explain why he used an energy penalty of 0.6% in Exhibit 82, when, in Exhibit 22 (§ C.4, at 3 of 5), he calculated the increase in the parasitic load to be 0.4%. In the discussion that follows, the values that Mr. Powers presented in Exhibits 22, 28 and 82 are compared with Mr. Grogan's calculations, which are presented in Exhibits 196, 197 and 198.

²² Exhibit 196 corresponds to Exhibit 82. Exhibit 197 corresponds to Exhibit 22 (WP-5). Exhibit 198 corresponds to Exhibit 28 (WP-11).

the once-through cooling system is 0.7 MW. To support this result, Mr. Grogan referred to the cooling water pump curve for Unit 4, which is attached to Exhibit 197. If Unit 4 is retrofitted with a closed-cycle cooling system, Mr. Grogan stated that upgrading the condenser would decrease the overall efficiency of the unit, contrary to Mr. Powers' estimate. (Exhibit 197; Tr. [Dec. 19] 2979-2980 and 2983-2984.)

The basis for Mr. Grogan's opinion is the resulting change in the flow rate through the condenser. Regardless of whether the condenser is upgraded, Mr. Grogan explained that the current flow rate through the condenser under once-through conditions would decrease from 142,000 gallons per minute (gpm) to 110,000 gpm if Unit 4 is retrofitted with a closed-cycle cooling tower. The reduction in flow, even with an upgraded condenser, would result in an overall decrease in efficiency, according to Mr. Grogan. (Exhibit 197, Danskammer Unit 4, Closed-cycle System Performance; Tr. [Dec. 19] 3134-3136.)

Mr. Grogan estimated that the parasitic load associated with the condenser upgrade would be 1.9 MW. Mr. Grogan anticipated further that the parasitic load associated with the cooling tower fans would be 1.5 MW, based on the larger cooling tower design he developed. Therefore, the estimated parasitic load associated with retrofitting Unit 4 with a closed-cycle cooling system would be 6.4 MW (3.0 MW + 1.9 MW + 1.5 MW = 6.4 MW). The net increase in parasitic load on Unit 4 from the proposed retrofit would be 5.7 MW (6.4 MW - 0.7 MW = 5.7 MW), which would increase the parasitic load by 2.4% (5.7 MW/235 MW = 2.4%), rather than by 0.4%,²³ as Mr. Powers had estimated. (Exhibit 197; Tr. [Dec. 19] 2979-2980 and 2983-2984.)

In Exhibit 196, which is a revision of Mr. Powers' calculations presented in Exhibit 82, Mr. Grogan substituted 2.4% from Exhibit 197 into Section III of Exhibit 82. Based on a change in efficiency of 2.4%, Mr. Grogan calculated that: (1) NO_x emissions would increase by 142.1 tons per year, (2) SO₂ emissions would increase by 372.2 tons per year, and (3) PM₁₀ emissions would increase by 10.1 tons per year. Based on these calculations, Mr. Grogan concluded that the proposed retrofit of Unit 4 would increase SO₂ and NO_x emissions above the PSD threshold limits. As a result, Dynegy would be required to install additional pollution control equipment to control not only a net increase in SO₂ emissions, but also a net increase in

²³ See footnote 21.

NO_x emissions. (Exhibit 196, §§ III and IV; Tr. [Dec. 19] 2975-2978.)

After Mr. Powers revised his calculations in Exhibit 82, he acknowledged that the net increase in SO₂ emissions would exceed the PSD threshold limit of 40 tons per year if the Facility is retrofitted with a closed-cycle cooling system. Consequently, there is no dispute about the need to install an FGD system to reduce the anticipated increase in SO₂ emissions associated with retrofitting Unit 4.

With respect to NO_x emissions, Mr. Powers' revised calculations estimate that the net increase in NO_x emissions would be about 35 tons per year if the Facility is retrofitted. (Tr. 1243.) Mr. Grogan's calculations show that the net increase of NO_x emissions would exceed the 40 ton per year PSD limit (Exhibit 196, § III). Based on Mr. Grogan's estimates, Dynegy would have to install additional equipment to reduced the anticipated increase in NO_x emissions. Mr. Daley stated that Dynegy would use a selective catalytic reduction (SCR) system to control NO_x emissions. Mr. Daley explained further that the SCR system would have to be located near the common stack for Units 3 and 4 and adjacent to the FGD system. According to Mr. Daley, the cost of an SCR system for Units 3 and 4 would be \$56.5 million. (Tr. 1405, 1726, 1734.) The parties did not offer any information about the components associated with an SCR system, or the amount of space that these components would occupy. Therefore, the discussion that follows focuses on the components and related features of the FGD system.

2. Components, Location and Size of the FGD System

Based on the foregoing discussion, the Facility would need an FGD system if retrofitted with a closed-cycle cooling system. Consequently, the inquiry now focuses on what the required components of an FGD system would be, where these components would be located, and the amount of space that these components would occupy. According to Mr. Powers, the site of the decommissioned fuel oil storage tank, which is shown on the *Danskammer Site (1 of 2) Survey Map Showing Parcels and Easements* (Exhibit 111), would be the preferred location for the FGD system due to the proximity of this area to the existing railroad. Mr. Powers stated that storing limestone (a reagent) and gypsum (a by-product) could occupy large areas on the site, and opined that the reagents and products could be moved easily by rail or truck from this proposed location. With his prefiled rebuttal

testimony, Mr. Powers offered Exhibit 53²⁴ to show that in 1983, Central Hudson evaluated wet and dry FGD systems, and identified the wet FGD system as the preferred system, should one become necessary. (Tr. 432.)

With his rebuttal testimony, Mr. Powers included Exhibit 54, which is a description and a cost estimate for a Chiyoda wet FGD system. The Chiyoda wet FGD system had been proposed for the Weston Unit 4 facility, which is a 500 MW coal-fired plant in Wisconsin. The last page of Exhibit 54 is an area arrangement of the various components of the Chiyoda wet FGD system. According to Mr. Powers, Chiyoda wet FGD systems, like the one discussed in Exhibit 54, have been "ordered" by US coal-fired power plants that generate more than 6,000 MW of power (Tr. 432). Mr. Powers stated that the Chiyoda wet FGD system is relatively compact, and estimated that its main components occupy about 40,000 square feet. Mr. Powers stated that a similar system would fit in the general area of the decommissioned fuel oil tank on the site. (Tr. 432, 983-984.)

During Mr. Powers' cross examination, Dynegy offered Exhibit 67, which includes additional pages from the DEIS concerning the coal conversion of Units 3 and 4, as well as a plan for a wet FGD system. (Exhibit 67, Fig. 11-3; Tr. 577.) In addition to Exhibit 67, Mr. Ascenzi explained that sometime prior to the hearing, representatives from Sargent and Lundy, LLC, an engineering consulting firm, conducted a preliminary cost study for designing and installing a wet FGD system for Units 3 and 4. (Tr. 1501.) Mr. Ascenzi explained that after consulting with colleagues at Dynegy Midwest Generation, a representative from Sargent and Lundy, LLC, provided Mr. Ascenzi with a sketch of the components for an FGD system via e-mail, and Mr. Ascenzi forwarded the sketch to Mr. Allen. (Tr. 1486, 1502.) Mr. Allen then transferred the FGD components from the sketch to Exhibit 114. Mr. Ascenzi stated that he did not make any determinations about the size of the FGD components depicted on Exhibit 114. (Tr. 1507.)

²⁴ Exhibit 53 is § 11.6.3.2 (at 11-14 through 11-16) entitled, Flue Gas Desulfurization, from the *Draft Environmental Impact Statement (DEIS) for Coal Reconversion at Danskammer Point Generating Plant Units 3 and 4, Town of Newburgh, Orange County, New York*. Dynegy offered Exhibit 67, which includes additional pages from the DEIS, as well as a plot plan for a wet FGD system.

Although some of the components of the FGD system on Exhibit 67 are arranged differently on Exhibit 114, many components of the FGD system depicted in both exhibits would generally occupy the space where Mr. Powers has proposed to locate a closed-cycle cooling tower (*i.e.* Area 6). In particular, the inactive limestone storage area would be located on the open area south of the powerhouse and north of the sanitary system, and between the roadway and the bank of the Hudson River. (Exhibit 114, Configuration No. 1, Units 1-4.) It is significant to note that on Exhibit 114, portions of the emergency gypsum building and the gypsum house would be located at the site of the decommissioned fuel oil storage tank (Exhibit 111), as suggested by Mr. Powers.

According to Mr. Ascenzi, the following factors, among others, would be considered when sizing an FGD system for an electric generating facility. They are: (1) the sulfur content of the coal, (2) the size of the unit, (3) the heat input of the unit, (4) sources of limestone, and (5) options for storing the gypsum by-product. With respect to limestone, questions about how it would be transported to the site, and how it would be stored on site need to be addressed. With respect to gypsum, questions about whether it can be sold as a product, and if so, whether the market is year round or seasonal, need to be considered. Depending on these factors, Mr. Ascenzi stated that the size of the FGD system would vary accordingly. (Tr. 1503-1505.)

Mr. Powers estimated that the components of the FGD system presented on Exhibit 114 would occupy about 60,000 square feet (Tr. 984), and Mr. Allen accepted this estimate. (Tr. 1471.) Mr. Ascenzi stated that the FGD system on Exhibit 114 is properly sized for Units 3 and 4 for two reasons. First, it is about the same size as the system depicted in the DEIS for the coal conversion in 1985-86. (Exhibit 67.) Second, the sketch came from Sargent and Lundy, LLC, who has extensive knowledge about the Facility because the engineering firm has done work at the Facility before. (Tr. [Dec. 19] 3011.) Mr. Micheletti observed that the layout for the Chiyoda system in Exhibit 54 was not prepared for the Facility. According to Mr. Micheletti, the Chiyoda system has been installed at only one facility (presumably, Weston Unit 4, Wisconsin) in the United States. (Tr. [Dec. 19] 3012.)

Mr. Powers did not present sufficient evidence to determine whether the Chiyoda FGD system presented in Exhibit 54 is properly sized for Units 3 and 4, and that the Chiyoda configuration would be transferable to the Dynegy site. The

experts agree that the size of some of the components of the FGD system would vary. For example, the Chiyoda system in Exhibit 54 provides for a 30-day limestone storage area at 4,500 cubic yards, and an 88-hour gypsum storage bunker at 1,500 cubic yards. Whether these Chiyoda components would be similarly sized at the Facility is unknown. Therefore, for the reasons stated by Mr. Ascenzi in the preceding paragraph, I find that the FGD design provided by Stanley and Lundy, LLC, which is depicted on Exhibit 114, is a more credible design for the Facility than the Chiyoda design depicted in Exhibit 54.

Retrofitting Unit 4 with a closed-cycle cooling system would require a larger cooling tower than originally proposed, and the installation of additional pollution control equipment. Based on the foregoing discussion, I find that the installation of the FGD system at the Facility would preclude the installation of any cooling towers south of the powerhouse on what has been identified as Area 6. As a result, Configuration Nos. 3, 4, 5, 6, 7 and 8, as well as Partial Retrofit Configuration Nos. 2, 3 and 4 would not be available with respect to the best technology available determination.

G. Cooling Towers on Area 2

Mr. Powers identified the site of a decommissioned waste water treatment lagoon located on the northern part of the site between the right-of-way for the FAA beacon and the waste water treatment building as a potential location for a closed-cycle cooling tower. In the discussion concerning the proposed locations for the closed-cycle cooling towers, this site has been identified as Area 2. Based on Exhibit 19, the northern side of the proposed four-cell cooling tower placed on Area 2 would line up with the northern side of the waste water treatment building. As depicted in Exhibit 19, the eastern end of the cooling tower would be about 25 feet from the waste water treatment building. In addition, the western end of the cooling tower would extend past the current, active waste water treatment lagoons by about 30 feet.

Lawrence R. Wilson testified on behalf of Department staff. He is a Biologist in the Steam Electric Unit with the Department's Division of Fish, Wildlife and Marine Resources. (Exhibit 139.) In his professional capacity, Mr. Wilson has visited the Facility many times. (Tr. 2124, 2186, 2195, 3333.)

After reviewing the proposed closed-cycle cooling retrofit configurations depicted in Exhibit 19, Mr. Wilson initially

concluded there would be sufficient space on Area 2 to accommodate a four-cell cooling tower. (Tr. 2124, 2194, 2195.) Subsequently, Mr. Wilson visited the site to verify his initial conclusion. (Tr. 2124.) During the site visit, Mr. Wilson stood with his back to the northwest corner of the waste water treatment building and looked west toward the FAA beacon and the railroad tracks. (Tr. 2195, 2198.) He observed that the crest of the river bank extended farther south than depicted in Exhibit 19 into Area 2. (Tr. 2196, 2204, 2205.) Based on his observations, Mr. Wilson concluded that Area 2 is not sufficiently wide enough to accommodate the proposed cooling towers. Rather, he concluded that at least a portion of the four-cell cooling tower proposed for this location would be in the Hudson River. (Tr. 2124, 2200.)

Exhibit 199 is an aerial photograph of the Facility taken on December 17, 2002. During the hearing, Mr. Wilson marked Exhibit 199 in the following manner. He placed an "X" where he stood with respect to the northwest corner of the waste water treatment building. (Tr. 3336, 3337, 3338.) Then, using a green marker, Mr. Wilson marked the approximate location of the river bank along the northern edge of the site as he had observed it during his last site visit. (Tr. 3339.) After comparing Exhibit 199 with Exhibit 19, Mr. Wilson stated that the crest of the river bank shown on Exhibit 199 is more inland than what is depicted on Exhibit 19. (Tr. 3341.)

According to Mr. Wilson, it is unlikely that Department staff would issue a SPDES permit that would require Dynegy to fill in portions of the Hudson River in order to construct the proposed cooling tower on what has been identified as Area 2. Mr. Wilson explained there are permit issuance standards outlined in Environmental Conservation Law (ECL) Article 15 related to obtaining a permit to put fill in the navigable waters of the state, like this reach of the Hudson River. Mr. Wilson stated that thousands of acres of watered areas in and along the Hudson River have been filled in over the last 100 years. He observed that placing fill in the Hudson River would result in the permanent loss of aquatic habitat. Based on the foregoing, Mr. Wilson opined that it would be very unlikely that Staff would issue a permit to fill in a portion of the Hudson River for the proposed cooling tower. (Tr. 3364.)

I assign significant weight to Mr. Wilson's testimony concerning the availability of Area 2 as a potential location for closed-cycle cooling tower. Although Mr. Wilson did not take any measurements during his site visit (Tr. 2196), his current and

prior professional positions require him to make accurate field observations, and he has many years of experience doing so. Moreover, Petitioners did not offer any evidence that either contradicted Mr. Wilson's testimony, or otherwise demonstrated that Mr. Wilson's observations related to this area of the site were inaccurate.

After considering Mr. Wilson's testimony and comparing Exhibit 199 with Exhibit 19, I find that the northern shore of the site is actually farther south than what is depicted on Exhibit 19. As a result, I agree with Mr. Wilson and find that Area 2 would not be wide enough to accommodate the four-cell cooling tower proposed by Mr. Powers. Given the anticipated length of the proposed four-cell cooling tower, there is not sufficient space to move it farther south due to the location of the current, active waste water treatment lagoons and associated facilities. As a result, Configuration Nos. 1, 2, 5 and 6, as well as Partial Retrofit Configuration No. 1 are not available technologies with respect to the best technology available determination.

H. Availability of Proposed Retrofit Designs

The first of two issues identified in the May 13, 2005 Interim Decision is whether a closed-cycle cooling system would fit on the site. The record of this proceeding shows that the closed-cycle cooling tower proposed by Petitioners for Unit 4, which would consist of six Marley F488 cells with six feet of film fill and extra fan blades, would be unacceptably undersized.²⁵ Alternative retrofit designs for Unit 4 initially considered by Mr. Powers, as well as others subsequently developed by Mr. Grogan would not fit on the site because they would be too long. As a result of this circumstance, Configuration Nos. 1, 4, 5, 6, 7 and 8, as well as Partial

²⁵ According to Mr. Powers, the proposed four-cell closed-cycle cooling tower for Unit 3 would be somewhat more "robust" than the six-cell tower proposed for Unit 4. (Tr. 917.) The adjudicatory hearing record includes significantly fewer details about the proposed closed-cycle cooling tower for Unit 3 compared to the details offered about the proposed retrofit of Unit 4. Furthermore, Dynegy focused its presentation on the six-cell closed cycle cooling tower for Unit 4. For purposes of discussion, it will be assumed, therefore, that the proposed wet cooling towers for Units 1, 2 and 3 are appropriately sized.

Retrofit Configuration Nos. 1, 2, 3 and 4 are not available for consideration of the best technology available determination.

In addition, the record establishes that the net increase in SO₂ emissions from the Facility would exceed the annual PSD threshold limit if Units 3 and 4 are retrofitted with a closed-cycle cooling system. The anticipated net increase in air emission would require Dynegy to install additional pollution control equipment at the Facility that would consist of a flue gas desulfurization system. As discussed in detail, there are several components associated with an FGD system, and these components must be installed near the common emission stack for Units 3 and 4 on the south side of the powerhouse. Although Mr. Powers proposed to install closed-cycle cooling towers at this location, described as Area 6, this area would not be available because components of the FGD system would be located there. As a result, Configuration Nos. 3, 4, 5, 6, 7 and 8, as well as Partial Retrofit Configuration Nos. 2, 3 and 4 are not available for consideration of the best technology available determination.

Area 2, which is the site of the decommissioned waste water treatment lagoon on the northern end of the site, is not wide enough to accommodate the proposed four-cell cooling tower associated with Configuration Nos. 1, 2, 5 and 6, as well as Partial Retrofit Configuration No. 1. Consequently, these configurations are not available for consideration of the best technology available determination.

With respect to Configuration Nos. 2, 3, 4 and 8, as well as Partial Retrofit Configuration No. 2, the record is silent about whether the alternative retrofit designs for Unit 4 initially considered by Mr. Powers and subsequently developed by Mr. Grogan would fit on the area west of the railroad tracks (Area 7). Dynegy and Department staff raised several concerns that were addressed at the hearing about locating cooling towers west of the tracks. The disputes, however, do not need to be resolved because other components of the proposed retrofit configurations could not be located on the site. For example, concerning Configuration No. 2, the cooling tower for Unit 4 would be located west of the railroad tracks. However, a four-cell cooling tower is proposed to be located on Area 2 for Units 1 and 2, and this area is not wide enough to accommodate a cooling tower. With respect to Configurations Nos. 3, 4 and 8, as well as Partial Retrofit Configuration No. 2, a cooling tower for various electric generating units would be located on Area 7. However, for these same configurations, a cooling tower has also been proposed to be located on the area south of the powerhouse

(Area 6) where the FGD system would be installed. Area 6 is not available because components of FGD system would need to be installed in Area 6 if the Facility is retrofitted with a closed cycle cooling system.

The circumstances discussed above, whether considered separately or in combination with each other, show that at least one component of the twelve retrofit configurations proposed by Petitioners would not fit on the site. Therefore, none of the proposed configurations are available for consideration of the best technology available determination. Because the threshold question of whether a closed-cycle cooling system would fit on the site has been decided in the negative, no additional potential impacts identified in the May 13, 2005 Interim Decision related to retrofitting the Facility with a closed-cycle cooling system need to be considered further.

III. Danskammer Alternative Technology Evaluation Model (DATEM)

Proposed Condition Nos. 8 and 9 (Exhibit 6, at 14 and 15 of 25) of the revised draft SPDES permit would require Dynegy to monitor impingement and entrainment for two years, and report the results in tabular and graphic formats to Department staff. In addition, Proposed Condition No. 11 (Exhibit 6, at 15 of 25) would require Dynegy to implement a flow reduction and outage program by managing flow and the cooling water discharge temperature on a daily basis using DATEM. Within the first two years of the permit term, Proposed Condition No. 11(a) would require Dynegy to reduce flows so that entrainment mortality is reduced by at least 70% and impingement mortality is reduced by at least 80%. During the last three years of the permit term, Proposed Condition No. 11(b) would require Dynegy to reduce flows so that entrainment mortality is reduced by at least 80% and impingement mortality is reduced by at least 85%.²⁶ Compliance with the performance standards would be based on cumulative daily averages (CDA) of the percent reductions.

DATEM is a computer calculation tool that Dynegy would use to quantitatively assess various technologies and operating strategies for complying with the revised draft permit conditions, and to track the performance of applied technologies and operating strategies. (Tr. 2747.) DATEM operates on the principle that entrainment and impingement mortality can be reliably estimated based on: (1) the volume of cooling water

²⁶See footnote 6.

withdrawn; (2) the density of organisms present in the vicinity of the intake structure; and (3) the fractional mortality of organisms involved in the intake. (Tr. 2748.)

Within the context of DATEM, "fractional mortality" means the percentage of organisms that would not survive entrainment and impingement under a given set of criteria. The fractional mortality rate associated with entrainment depends on the mechanical and thermal stresses to which organisms are exposed as they pass through the cooling water system. Mechanical stress occurs from shear, turbulence, pressure changes, and contact with surfaces of the cooling system components. Thermal stress occurs when an organism is heated beyond its zone of thermal tolerance. (Tr. 2748-2749.)

DATEM incorporates fractional mortality estimates for six fish species: striped bass, white perch, American shad, Blueback herring, Alewife and bay anchovy. (Tr. 2749.) However, Dynegy and its predecessor, Central Hudson, have not included bay anchovy when assessing compliance with the entrainment and impingement performance standards because the extensive monitoring data show that bay anchovy have low involvement with the Facility. As a result, Department staff agreed not to include bay anchovy. (Tr. 2749.) Furthermore, the distribution of American tomcod in the reach of the Hudson River near the Facility is similar to that of the bay anchovy. Therefore, tomcod are not considered in DATEM assessments. (Tr. 2750.)

As noted above, the reliability of DATEM was identified as an issue for adjudication. The issue was divided into three parts. The first is whether full pumping capacity should be used as the baseline even though the Facility has historically not operated at full capacity. The second part is whether it is appropriate to assume any entrainment survival when estimating mortality. The third concerns the accuracy of the temperature data use in DATEM. (Exhibit 17, at 19-21.)

Dynegy offered the expert testimony of a panel of witnesses to address the DATEM issue. The panel members were Lawrence W. Barnthouse, Ph.D., Charles V. Beckers, Jr., Charles C. Coutant, Ph.D., Martin W. Daley, William P. Dey, Steven M. Jinks, Ph.D., and John R. Young, Ph.D. Dr. Barnthouse is the President and Principal Scientist with LWB Environmental Services, Inc., (Hamilton, OH). (Exhibit 174; Tr. 2736.) Mr. Beckers is a registered professional engineer in Rhode Island. He is a Senior Project Manager for Mathematical Modeling in the Natural Resource Management and Permitting Section of HDR/LMS (formerly Lawler,

Matusky & Skelly Engineers, LLP) (Pearl River, NY). (Exhibit 175; Tr. 2736.) Dr. Coutant is recently retired from his position as a Distinguished Research Ecologist for the Environmental Sciences Division of the Oak Ridge National Laboratory (Oak Ridge, TN). (Exhibit 176; Tr. 2736.) Mr. Daley is the Senior Director of Regulatory Affairs and Administrative Services with Dynegy Northeast Generation, Inc. (Exhibit 109; Tr. 2736). Mr. Dey is a Senior Scientist/Associate with ASA Analysis & Communication, Inc. (Washingtonville, NY). (Exhibit 177; Tr. 2737.) Dr. Jinks is also a Senior Scientist/Associate with ASA (Washingtonville, NY). (Exhibit 178; Tr. 2737.) Finally, Dr. Young is a Senior Scientist/Associate with ASA (Lemont, PA). (Exhibit 173; Tr. 2736.) For the reasons outlined further below, the members of Dynegy's fisheries panel favor the use of a full-flow baseline and crediting the Facility for entrainment survival.

Lawrence R. Wilson testified for Department staff. He is a Biologist in the Steam Electric Unit of the Department's Division of Fish, Wildlife and Marine Resources. (Exhibit 139.) Mr. Wilson outlined Department staff's rationale for selecting the full-flow baseline and choosing to credit the Facility for entrainment survival. (Tr. 2091-2092.)

Petitioners offered the expert testimony of Peter A. Henderson, Ph.D., Director, Pisces Conservation, Ltd., Oxford, United Kingdom. (Exhibit 151; Tr. 2438-2440.) Although Dr. Henderson stated that DATEM is well constructed and perfectly reliable, (Tr. 2530), he opposed using the full-flow baseline for determining compliance with entrainment and impingement performance standards at the Facility, as well as crediting the Facility for entrainment survival.

A. Baseline Flow

Dr. Young favors the use of the full-flow baseline for three reasons. First, the full-flow baseline would allow Department staff to evaluate reductions from the Facility's potential to entrain aquatic organisms. Second, using the full-flow baseline would allow Department staff to standardize the compliance requirements associated with entrainment and impingement mortality for all facilities in the state. Third, using the full-flow baseline recognizes that any reduction in flow, regardless of the reason, has the effect of reducing entrainment mortality. According to Dr. Young, relying on anything other than full-flow would unfairly penalize facilities that have

operated at lower pumping levels by not allowing them credit for any recently implemented flow reductions. (Tr. 2758.)

Mr. Wilson explained that Department staff had tentatively determined, for purposes of developing the draft SPDES renewal permit, that full-flow should be used as the baseline for the Facility. Mr. Wilson defined "full-flow" as the flow of cooling water when all pumps at the Facility are continuously operating at full capacity every day of the year. Referring to 40 CFR 125.93, Mr. Wilson stated that relying on the full-flow baseline would be consistent with US EPA's Phase II rule for existing facilities. Mr. Wilson stated further that the full-flow baseline fulfills the mandate of both federal and state law to protect aquatic resources, and ensures fairness among energy producers. (Tr. 2107.)

Regardless of the Facility's historic operating practices, Mr. Wilson explained that every electric generating facility, including the Danskammer Facility, has the potential to operate at full-flow conditions pending operational ability and market demand as determined by the New York Independent System Operator (NYISO) and the Department of Public Service (DPS) given the deregulated nature of the electric generating industry. Although full-flow may not be the typical operating condition for all facilities for most of the year, some facilities that use the Hudson River as their source of cooling water, do operate continuously at full-flow when generating electricity, and some of the Hudson River facilities do generate electricity every day of the year, according to Mr. Wilson. (Tr. 2108.)

Department staff considered two alternatives to full-flow. They are the standard capacity factor, and past performance. With respect to the first alternative, Department staff considered using a reduced baseline flow calculated by multiplying full-flow by a standard capacity factor, which would be a percentage of maximum annual electric power actually generated at a particular facility (e.g. 80%, 85%, or 90% of maximum generating capacity). The baseline flow would be calculated using this percentage of the maximum generating capacity.

According to Mr. Wilson, the standard capacity factor alternative would require Staff to establish a single capacity factor for all existing electric generating facilities, and to decide how to distribute these reductions in cooling water flow during a particular period of time. For example, the flow limit could be imposed either year round, or during biologically

important times. Mr. Wilson stated that it would be difficult to base the capacity factor on objective criteria, and would likely result in favoring some facilities over others. (Tr. 2109.)

With respect to the second alternative, Department staff considered using past performance (i.e. historic cooling water usage) at each electric generating facility as the baseline. The time frames that Staff considered were: (1) average flow since construction; (2) average flow over the last three to five years; and (3) the greatest flow since construction. Mr. Wilson stated that this alternative would be more objective than using a standard capacity factor, but that past performance would be difficult to implement now in the deregulated electric generating industry. In addition, operations at electric generating facilities vary from year to year based on the weather and fuel costs. Also, units may be off-line for maintenance and repairs. As a result, Mr. Wilson concluded that past performance would not be an accurate indicator of either future operations at a particular electric generating facility, or future power demands given the deregulated nature of the electric generating industry. (Tr. 2109, 3259, 3301-3302.) Mr. Wilson concluded further that using past performance to calculate the baseline flow would result in a "moving target." (Tr. 2140-2141.)

Accordingly, Mr. Wilson explained that establishing a baseline other than full-flow would favor those facilities that run continuously at full-flow conditions, and would penalize facilities that have made recent investments to reduce flow and, thereby, reduce impacts associated with entrainment and impingement. Mr. Wilson stated that Department staff relied on the guidance outlined in Exhibits 144 and 145,²⁷ which support the use of the full-flow baseline. (Tr. 2110.)

To prepare for the hearing, Dr. Henderson reviewed DATEM model version 3, dated September 2, 2005. (Exhibit 179.) Dr. Henderson explained that DATEM assumes a direct relationship

²⁷Exhibit 144 is a letter dated January 24, 2005 from the DEC Deputy Commissioner of Natural Resources to Benjamin H. Grumbles, Assistant Administrator, US Environmental Protection Agency, Washington, DC. Exhibit 145 is a letter dated January 31, 2005 from the DEC Executive Deputy Commissioner to John G. Holsapple, Director, Environmental Energy Alliance of New York, Albany, NY. The letters outline how Department staff would generally implement the Phase II rule requirements in the Department's SPDES permit program.

between flow and the number of organisms entrained and impinged. On a weekly basis, DATEM calculates the mortality associated with entrainment and impingement based on historical data that estimate the concentration of fish species and their various life stages in the water column during a particular week. The estimate is then adjusted for survival. The adjusted result is compared with a baseline flow and the estimated mortality level. (Tr. 2453.)

The benefit to aquatic organisms that would result from the implementation of the proposed flow reduction and outage program outlined in the revised draft SPDES permit (Exhibit 6, Proposed Condition No. 11, at 15 of 25) is a reduction in entrainment and impingement mortality. Dr. Henderson stated, however, that DATEM would overestimate or "inflate" these intended benefits if the baseline is calculated by using full-flow. (Tr. 2454-2456.)

Dr. Henderson noted that the Facility has historically withdrawn about 80 billion gallons annually from the Hudson River, which is about half of its design capacity. Dr. Henderson noted further that, historically, Units 1 and 2 have "rarely" been used. (Tr. 2474.) Given these circumstances, Dr. Henderson contended that using the full-flow baseline at the Facility would be counterproductive because it would encourage the retention of old, little used units, such as Units 1 and 2 at the Facility, while discouraging the use of other, more efficient and productive facilities. (Tr. 2481.) Although Dr. Henderson acknowledged that averaging the flow rate based on past performance would vary over time (Tr. 2690), he favors using that method to calculate the baseline. Dr. Henderson recommended using the recent five-year average flow as the baseline. (Tr. 2597, 2681.)

Given that the term for a SPDES permit is five years, Mr. Wilson objected to using past performance to calculate the baseline flow because the baseline would shift from year to year. (Tr. 3302-3303.) Dr. Young objected to using past performance to calculate the baseline flow for the same reason. (Tr. 2791.)

The baseline flow is the initial set of operating assumptions against which DATEM will assess whether actual operating conditions at the Facility would result in reductions in entrainment and impingement mortality. The results of the assessment will demonstrate whether the Facility complies with the performance standards outlined in the revised draft SPDES permit for reducing entrainment and impingement mortality (see Exhibit 6, Proposed Conditions Nos. 11a and 11b, at 15 of 25).

No party to the captioned matter favored calculating the baseline using a capacity factor. During the hearing, the parties identified the advantages and disadvantages of calculating the baseline using either full-flow or past performance. Based upon a review of the record and for the reasons outlined below, I find that calculating the baseline by using full-flow is appropriate.

In August 2002, the Department expressed support for nationally-applicable minimum performance standards for limiting mortality from entrainment and impingement at electric generating facilities with cooling water intake structures.²⁸ The basis, in large part, for this support was that national performance standards would ensure fair competition among these facilities. (Exhibit 142.²⁹) After minimum performance standards for limiting entrainment and impingement mortality were proposed, the inquiry focused on how to implement these standards fairly and consistently in an era of governmental deregulation of the electric generating industry. By letter dated January 24, 2005, the DEC Deputy Commissioner for Natural Resources stated that the Department would determine compliance with the proposed performance standards "compared with a baseline when the facility is operating at full-flow and full capacity." (Exhibit 144.)

Mr. Wilson has reasonably observed that every electric generating facility on the Hudson River has the potential to operate at full-flow conditions given the deregulated nature of the electric generating industry. Although full-flow may not be the typical operating condition for every facility, Staff has also observed that some electric generating facilities operate continuously at full-flow. I find that calculating the baseline by using the full-flow capacity is a rational, conservative approach because the full-flow baseline would facilitate Staff's ability to determine compliance with the performance standards limiting entrainment and impingement mortality by all Hudson River electric generating facilities, on a comparative basis,

²⁸As noted in Footnote 6, the performance standards for limiting mortality from entrainment and impingement are the percentage reductions outlined in Proposed Condition Nos. 11a and 11b of the revised draft SPDES permit (Exhibit 6, at 15 of 25).

²⁹Exhibit 142 is a letter dated August 7, 2002 from the DEC Deputy Commissioner for Natural Resources to the US Environmental Protection Agency. The letter comments about the then proposed Phase II rule.

regardless of how frequently individual facilities may actually operate. By selecting the full-flow baseline, electric generating facilities would receive credit for reducing entrainment and impingement mortality when they do not operate.³⁰

Even though Department staff acknowledged that using the full-flow baseline could overestimate reductions in entrainment and impingement mortality (Tr. 3230), I find that the potential to overestimate reductions in entrainment and impingement mortality would not be as great as Dr. Henderson claimed. Moreover, I find that Staff has offered a reasoned explanation for choosing not to calculate the baseline by using past performance. As explained by Mr. Wilson, using past performance to calculate the baseline raises significant concerns about selecting the appropriate time frame (*i.e.* average flow since construction, average flow over the last three to five years, or the greatest flow since construction), and would create a baseline that shifts from year to year.

Finally, although Dr. Henderson advocated calculating full-flow by using past performance, I do not find his opinion persuasive particularly after he acknowledged the difficulty associated with selecting any method to calculate the baseline flow. (Tr. 2692-2693.) Accordingly, I find that the full-flow baseline (*i.e.* 316,000 gallons per minute [Exhibit 3D; Tr. 3276]) should be used to determine the Facility's compliance with the entrainment and impingement performance standards outlined in Proposed Condition No. 11 of the revised draft SPDES permit (Exhibit 6, at 15 of 25).

B. Entrainment Survival

Dr. Henderson opined that it would be inappropriate to assume entrainment survival when employing DATEM to assess compliance with the performance standards outlined in the proposed draft permit conditions. He explained that the early life stages of fish are very delicate, and that the data collected from relatively short-term survival studies do not provide a reliable estimate of the eventual fate of entrained organisms. According to Dr. Henderson, studies show that the death rate of fish in their early life stages following

³⁰With a full-flow baseline, Dr. Henderson acknowledged that environmental benefits would result when electric generating facilities that withdraw cooling water from the Hudson River do not operate. (Tr. 2547.)

entrainment increases over time. Dr. Henderson attributes the decline in post-entrainment survival to injuries that ultimately manifest themselves many days after entrainment has occurred. (Tr. 2466, 2487.)

To support his opinion, Dr. Henderson referred to studies (e.g. EPRI Review of Entrainment Survival Studies: 1970-2000, 1000757 December 2000, Table A-12) that were undertaken at the Facility in 1975 in which all of the post-yolk sac larvae died within 96 hours. Dr. Henderson noted that it was not possible to estimate the mortality rate of entrained organisms after 96 hours because the controls, which had not been exposed to entrainment, also died within that period.³¹ Dr. Henderson concluded that the only conservative approach would be to assume no entrainment survival. (Tr. 2466, 2487.)

Dr. Young explained that entrainment monitoring at the Facility was conducted from 1974 through 1987. In particular, Dr. Young noted that intensive weekly entrainment sampling was undertaken from 1982 to 1987. These studies were designed to describe species composition, abundance, seasonal and daily distribution patterns, and the period of entrainment. Because sampling was more intensive between 1982 and 1987, and because the data from the 1982 to 1987 sampling period is more recent than that from the prior sampling studies from the 1970s, Dr. Young stated that data collected from 1982-1987 are the basis for the entrainment density inputs for DATEM. (Tr. 2751-2752.)

Dr. Jinks supervised the entrainment monitoring studies at the Facility from 1982-1987. He explained that samples were collected at the beginning of the intake canal behind the trash racks. After collection, Dr. Jinks stated that preserved samples were sent to the laboratory, where organisms were sorted, identified by species and life stage, and counted. The length of the organisms were also recorded for sub-samples of each species. (Tr. 2752, 2811.)

The results of the entrainment studies undertaken at the Facility have been made available to Department staff and the public in a series of annual reports. (Tr. 2753.) Dr. Barnthouse stated that he reviewed the entrainment studies, and concluded that they were conducted under rigorous quality standards. He stated further that the entrainment studies meet

³¹According to Mr. Wilson, the control organisms died because they were not fed during the pendency of the study. (Tr. 2142.)

generally accepted standards and practices for collecting scientific data. Dr. Coutant concurred with Dr. Barnthouse's opinion concerning the development and implementation of the entrainment studies. Dr. Coutant characterized the studies that Dr. Jinks supervised as the model for long-term monitoring with respect to entrainment. (Tr. 2754.) According to Dr. Coutant, the entrainment survival assumptions that would be used in DATEM are reasonable and reliable. (Tr. 2765.)

Dr. Young opined that the entrainment data from the 1980s should be used to assess compliance with the performance standards outlined in the revised draft SPDES permit. According to Dr. Young, the data set is robust, statistically valid, and exceeds what is available at most other electric generating facilities. Dr. Young stated that the temporal patterns, observed in the 1980s, concerning the occurrence of various life stages of the relevant fish species have remained consistent over time. (Tr. 2754.)

Based on his review of the studies, Mr. Wilson stated that entrainment survival varies by species and life stage, and among facilities (Tr. 2112). Mr. Wilson acknowledged the difficulty in collecting data concerning long-term survival after entrainment. In general, Mr. Wilson observed that fish larvae have a very high natural mortality rate. In Mr. Wilson's opinion, most mortality observed after the first few hours following entrainment is likely due to other factors. (Tr. 2142-2143.) Therefore, Mr. Wilson concluded that a facility should not receive credit for entrainment survival unless it can provide scientifically valid data from rigorous site-specific studies. (Tr. 2112.)

Mr. Wilson stated, nonetheless, that for more than 25 years, rigorous studies concerning entrainment survival have taken place at the Facility (Tr. 2112), which Department staff has approved (Tr. 3320). Based on these site-specific studies, Mr. Wilson concluded that it would be appropriate to credit the Facility for entrainment survival. (Tr. 3319.)

As noted above, the fractional mortality rate associated with entrainment depends on mechanical as well as thermal stresses. The intake-discharge temperature differential limits the maximum discharge temperature of the non-contact cooling water based on the ambient temperature of the Hudson River. The biological fact sheet (Exhibit 3D, at 4 of 8) explains that the 1987 SPDES permit had two intake-discharge temperature differentials. From October 17 to May 14 (*i.e.* the winter), the temperature differential was limited to 34.2°F. From May 15 to

October 16 (*i.e.* the summer), the temperature differential was limited to 19.0°F. According to the revised draft SPDES permit, however, the daily maximum discharge temperature from the non-contact cooling outfalls (002, 003 and 004) would be 100°F (37.8°C).³² The revised draft SPDES permit further limits the discharge temperature as follows:

"[t]he 100°F maximum discharge temperature limitation applies when intake water temperature is less than or equal to 81°F (27.2°C). If the intake water temperature exceeds 81°F (27.2°C), then incremental (degree for degree) increases in the discharge maximum temperature above 100°F are allowed." (Exhibit 6, Footnote (a), at 12 of 25.)

According to Dr. Henderson, DATEM assesses the effects of changes in temperature that entrained organisms experience as a component of the mortality rate. (Tr. 2491.) Because the temperature of the cooling water discharged from the Facility could be higher than previously authorized given the terms of the revised draft SPDES permit, Dr. Henderson stated that estimated entrainment survival related to thermal stress should decrease. (Tr. 2459.)

For each species and life stage, Dr. Henderson explained that DATEM tracks two discharge temperature parameters, referred to as X1 and X2. X1 is the temperature below which no mortality would result. X2 is the temperature above which 100% mortality is assumed. Between these two discharge temperatures, DATEM assumes that mortality increases directly with temperature. (Tr. 2491, [Dr. Jinks] 2762.)

Dr. Henderson explained that DATEM averages the daily discharge temperatures for each week. (Tr. 2491, 2661, 2664.) According to Dr. Henderson, the averaging process is problematic because the averaging process could mask the actual effects of

³²In Exhibit D (at 9) to the October 14, 2003 petition for full party status, Petitioners asserted an issue for adjudication about the proposed change in the discharge temperature. The ALJ determined that the proposed issue was not substantive and significant (Ruling on Proposed Issues for Adjudication and Petitions for Party Status, March 25, 2004, at 20-21). Petitioners did not appeal from this particular ruling. Consequently, the Interim Decision does not discuss this proposed issue. Absent any appeal, the ALJ's ruling on this proposed issue stands.

thermal stress. (Tr. 2495, 2657-2658.) Dr. Henderson stated that DATEM has no mechanism to address periods when units are not in full operation over a seven-day period. As a result, days with little generation and flow contribute as much to the average temperature, as days when flow and generation are high. (Tr. 2491.) Dr. Henderson concluded that DATEM would significantly underestimate the entrainment mortality associated with thermal stress because the weekly average discharge temperatures for the Facility would be near or below X1 when electric generating units are either not generating or generating below capacity. (Tr. 2492.)

Dr. Young explained that the thermal tolerance studies were conducted during the 1970s, and maintained that the methodologies are valid. (Tr. 2762.) According to Dr. Jinks, the results of these studies demonstrate that the more important factors in determining entrainment mortality associated with thermal stress are the exposure temperature and, to a lesser degree, the length of the exposure. Dr. Jinks stated that the thermal stress component associated with entrainment mortality is typically negligible when temperatures in the cooling system remain below the threshold temperature (*i.e.* < X1). (Tr. 2762.)

Dr. Young explained further that DATEM assessments can use actual intake and discharge temperatures. According to Dr. Young, the use of actual intake and discharge temperature data eliminates any potential inaccuracies and, therefore, provides a reliable assessment of compliance with the performance standards. (Tr. 2767.)

The time periods for the data tracked by DATEM vary. For example, flow, as well as the water intake and discharge temperatures for each electric generating unit at the Facility are monitored daily. (Exhibits 171, 172, 183, 191, 204). The historical data related to the density of organisms in the water column in the vicinity of the Facility,³³ however, are presented in weekly increments (Monday through Sunday). As a result, adjustments for entrainment survival are presented on a weekly basis rather than on a daily basis. (Exhibits 179, 180.) Consequently, I agree with Dr. Henderson that estimates of entrainment mortality associated with thermal stress for a particular unit could be underestimated when a particular unit

³³These data are the results of the entrainment survival studies undertaken at the Facility over the past two and one-half decades.

operates for less than seven days during a particular Monday to Sunday period, and if the resulting average temperature is based on that same seven day period.

The example provided in Dr. Henderson's prefiled rebuttal testimony illustrates the outcome described above. During the week of May 17, 2004, Unit 2 operated for four consecutive days, and then went offline for the remaining three days. According to Dr. Henderson, DATEM did not calculate a discharge temperature average based on the actual four days of operation, but on seven days. Even if the river temperature is included for the days that Unit 2 did not operated,³⁴ Dr. Henderson stated that the discharge temperature, based on a seven-day average would not accurately reflect the conditions that entrained organisms experienced during those days when Unit 2 operated. (Tr. 2492.)

Estimates of entrainment mortality associated with thermal stress, however, depend not only on the discharge temperature, but also on flow. I find that the more significant variable in estimating entrainment mortality is flow because, on a weekly basis, the density of entrained organisms is directly related to flow. As a result, the average weekly flow, which accurately would reflect the density of the organisms entrained, would moderate potential temperature overestimations with respect to entrainment mortality estimates.

Therefore, I find that the potential underestimation of entrainment mortality associated with thermal stress would not be as significant as Dr. Henderson contended. Other than the example offered in Dr. Henderson's prefiled rebuttal testimony (Tr. 2492), Petitioners offered nothing else to further substantiate Dr. Henderson's characterization.³⁵ Moreover, Dr. Henderson's cross-examination established that he did not have a complete understanding of how DATEM estimates were actually calculated. (Tr. 2658-2660, 2665-2667.)

³⁴When units are not operating, the discharge temperature would be the same as the intake temperature. The source of the intake temperature data is from the Poughkeepsie water supply intakes (§ III.C).

³⁵The apparent irregularity associated with Unit 3 for the week of May 17, 2004 was later corrected. (Exhibits 171, 191; Tr. 2494-2495, 2681, [Dec. 14] 3057-3060.)

With respect to allowing Dynegy to take credit for entrainment survival, Petitioners are concerned about a lack of conservatism associated with the DATEM inputs, which in turn will affect the assessment of whether the Facility would meet the entrainment reduction performance standards outlined in the revised draft SPDES permit. As noted above, the only conservative approach would be to assume no entrainment survival, according to Dr. Henderson.

The Department, however, has taken a cautious approach to considering whether to allow any credit for entrainment survival. In a letter dated June 2, 2003 to US EPA about the proposed Phase II rule, the DEC Executive Deputy Commissioner stated, in pertinent part, that:

"The Department agrees that caution must be used in interpreting the results of entrainment survival studies. Much of the research to evaluate ichthyoplankton entrainment survival has been conducted at facilities in New York State. These studies have demonstrated that survival rates are specific to species and to life stage. More important, the survival rates are specific to the facility being studied. Thus, any measure of entrainment survival must be based upon site-specific survival studies. Results from one facility should not be used to assess entrainment survival at another facility." (Exhibit 143, at 2 of 4.)

As outlined above, Department staff's determination to allow some credit for entrainment survival is limited to site-specific studies. Studies at the Facility began in the 1970s and continued through the 1980s. Additional studies would be required by the revised draft SPDES permit. (Exhibit 6, Proposed Condition No. 9, at 15 of 25.) The protocols and data collection methods for the site-specific studies have been refined and improved over the past two and one-half decades. In addition, Department staff has reviewed the protocols, and supervised data collection. In instances where data is less robust for a particular species or life stage, DATEM inputs would assume there is no entrainment survival (i.e. the fractional mortality rate would be 100%). (Tr. 2764). The results of the entrainment studies have been available to Department staff, the public, and scientists, who have reviewed and evaluated the studies and the results reported therein.

Petitioners have offered nothing to refute either the validity of the study protocols, or the reliability of the results from the entrainment studies undertaken at the Facility.

Therefore, I conclude that Petitioners' concern about a lack of conservatism associated with the DATEM inputs is unfounded. Accordingly, I find no basis to adjust the manner in which DATEM would credit entrainment survival.

C. Temperature

In their petition for full party status, Petitioners alleged inaccuracy in the temperature data entered into DATEM because the temperature input data do not account for recent increases in the temperature of the Hudson River. (Petition, October 14, 2003, at 24-25.) As part of their offer of proof, Petitioners asserted that Dr. Henderson would present data collected at the City of Poughkeepsie water supply intakes to show that the water temperature data entered into DATEM are about 5°F too low. (Petition, at 25.) In the May 13, 2005 Interim Decision, the Deputy Commissioner determined that the accuracy of the assumptions in DATEM concerning this temperature data would be an issue for adjudication. (Exhibit 17, at 19, 21.)

Dr. Young explained that DATEM uses daily temperature measurements collected at the City of Poughkeepsie water intakes, which are located approximately 10 miles upstream from the Facility. The data from the Poughkeepsie intakes provides an estimate of the water temperature at the Facility's intake. According to Dr. Young, the temperature data collected at the Poughkeepsie intakes are used in two ways. First, the data determine the amount of water that the Facility would need for cooling purposes. Dr. Young stated that when water temperatures are low, the Facility would draw less water from the Hudson River to cool the Facility compared to when the water temperature is higher. Second, the data from the Poughkeepsie intakes determine the temperatures to which entrained organisms would be exposed, and thus affect the thermal component of the entrainment fractional mortality rate.³⁶ (Tr. 2766.)

None of Dr. Henderson's prefiled testimony³⁷ speaks to the issue of whether the water temperature data entered into DATEM

³⁶The thermal component of the fractional mortality rate associated with entrainment was discussed in the preceding section.

³⁷See Tr. 2437-2471 for Dr. Henderson's prefiled direct testimony dated October 14, 2005, and Tr. 2472-2500 for Dr. Henderson's prefiled rebuttal testimony dated November 7, 2005.

are about 5°F too low. Though given the opportunity, Petitioners presented nothing at the adjudicatory hearing to support their initial offer of proof.

To address the accuracy of the water temperature data used in DATEM, Dynegy offered the expert testimony of Charles V. Beckers, Jr., who is a Senior Project Manager for Mathematical Modeling in the Natural Resource Management and Permitting Section of HDR/LMS (formerly Lawler, Matusky & Skelly Engineers, LLP). (Tr. 2736, Exhibit 175.) According to Mr. Beckers, the temperature data collected at the Poughkeepsie water supply intakes are reliable. Mr. Beckers explained that the data provide a representative measurement of the near-surface water temperature in the Hudson River at the time the measurements are taken. Mr. Beckers noted that the temperature data from Poughkeepsie have been widely used by the scientific and engineering community to address questions related to water temperatures in the reach of the Hudson River extending southward from the Poughkeepsie intakes to the vicinity of the Tappan Zee Bridge. (Tr. 2767.)

During the hearing, the parties agreed to waive their respective rights to cross-examine Mr. Beckers. Subsequently, the parties agreed further to allow Mr. Beckers' prefiled direct testimony to be incorporated into the record via an affidavit sworn to January 4, 2006. (Exhibit 175A; Tr. 2825-2826; 3559; see also Memorandum regarding Conference Call held on January 5, 2006 dated January 9, 2006, at 4.)

Mr. Beckers' testimony is unrefuted, and I assign it substantial weight. The information presented in Mr. Beckers' testimony speaks directly to the issue identified in the May 13, 2005 Interim Decision concerning the accuracy of the temperature assumptions in DATEM. (Exhibit 17, at 19, 21.) Accordingly, I find that the data collected at the Poughkeepsie water supply intakes concerning the near-surface temperature of the Hudson River are reliable. Based on this reliable source of data concerning the near-surface temperature of the Hudson River, I find further that the temperature assumptions in DATEM are accurate.

IV. Best Technology Available (BTA)

The final question to be resolved in this proceeding is whether the Facility, as conditioned by the revised draft SPDES permit, will implement the best technology available (BTA) for minimizing adverse environmental impacts. The May 13, 2005

Interim Decision identified the requirements outlined at 6 NYCRR 704.5 and state administrative decisional precedent (see e.g. *Matter of Athens Generating Company, LP*, Interim Decision, June 2, 2000, at 9), as the appropriate legal standard to be applied to the captioned matter. For several reasons, the May 13, 2005 Interim Decision expressly excluded reliance on the recently promulgated EPA Phase II Rule. (Exhibit 17, at 31; see also Exhibit 144, at 5-7; Exhibit 145, at 5-7; Exhibit 146, attached memo dated 3/18/05, at 1.)

The following discussion addresses the potential impacts associated with the design and the capacity of the cooling water intake structure on aquatic organisms in the vicinity of the Facility.³⁸ The following discussion briefly describes the undisputed facts related to river setting, the cooling water intake structure, and Outfalls 002, 003 and 004. The second part of the discussion outlines the elements of the four-step BTA analysis. The third part of the discussion considers whether the design and capacity of the Facility's cooling water intake structure would minimize adverse environmental impacts as required by 6 NYCRR 704.5.

A. River Setting, and Description of the Cooling Water Intake Structure and Outfalls 002, 003 and 004

The Facility is located on the west shore of the Hudson River at river mile 65 in the Town of Newburgh, Orange County. The Facility consists of four single-cycle steam driven electric generating units. The total generating capacity of the Facility is 491 megawatts.

The intake canal is located on the north side of the site. The intake canal is open and at river level. The mouth of the intake canal is 115 feet wide and quickly narrows to 34 feet. The intake canal is 11 feet deep and 450 feet long. At the present time, water is drawn into the canal by single-speed

³⁸No party to the captioned matter asserted any issues related to the location of the Facility's cooling water intake structure. Therefore, the analysis that follows does not need to address the location criterion of the BTA standard. Similarly, no party asserted any issues related to the construction of the Facility's cooling water intake structure. Issues related to the construction of closed-cycle cooling towers on the site relate to the capacity criterion, and will be addressed in § IV.C.2 of the BTA discussion.

pumps. Units 1 and 2 each have two cooling water pumps, and each pump is rated at 21,000 GPM. Unit 3 has two pumps and each pump is rated at 41,000 GPM. Unit 4 has three pumps and each pump is rated at 50,000 GPM. The Facility's total maximum design flow is about 316,000 GPM or about 455 MGD. (Exhibit 3D; Tr. 3276.)

A series of traveling screens are located in front of the cooling water pumps. For Units 1, 2 and 4, the mesh of the traveling screens is 3/8 inch square. For Unit 3, the mesh of the traveling screens is 1/8 inch square. The purpose of the screens is to prevent debris from entering the pump chambers and condensers. The screens are continuously rotated and sprayed with high pressure water to flush them. The wash water is directed back to the river through a sluice that exits through the bulkhead. This point source is identified as Outfall 001 in both the current, and the revised draft SPDES permit.

Aquatic organisms, smaller than the mesh, pass through the screens and travel through the pumps and condensers. After the non-contact cooling water circulates through the Facility, it is discharged from outfalls located on the south side of the site. Units 1 and 2 discharge non-contact cooling water via Outfall 002. Unit 3 discharges non-contact cooling water at Outfall 003, and Unit 4 discharges at Outfall 004. The three outfalls (002, 003 and 004) for the non-contact cooling water are submerged and are located adjacent to each other.

B. The Four-Step BTA Analysis

Based on administrative decisional precedent,³⁹ the following questions must be addressed to determine whether the best technology available is being applied to cooling water intake structures that are associated with thermal discharges from point sources. The first question is whether a facility's cooling water intake structure may result in any adverse environmental impacts. The second question is whether the location, design, construction, and capacity of the cooling water intake structure reflect the best technology available for minimizing adverse environmental impacts. The third question considers whether there are practicable alternative technologies available to minimize the adverse environmental effects. The final question relates to whether the costs of alternative technologies are wholly disproportionate to the environmental benefit to be gained.

The threshold for determining whether any facility's cooling water intake structure would result in any adverse environmental impacts is very low. In a letter dated August 7, 2002, the DEC Deputy Commissioner for Natural Resources stated that any entrainment or impingement mortality would be considered an adverse environmental impact. (Exhibit 142, at 6.) Given this low threshold, 6 NYCRR 704.5 requires a consideration of each of the following four factors: location, design, construction, and capacity. The Commissioner has previously held⁴⁰ that determining whether a particular technology is the best one available is to be made on a case-by-case basis considering various factors, including costs, the age of the facility, the levels of entrainment and impingement mortality, the additional energy, if any, needed to support improved technology, or other relevant concepts.⁴¹ As noted above, the location and

³⁹See *Matter of Mirant Bowline, LLC*, Decision, March 19, 2002, at 11; *Matter of Athens Generating Company, LP*, Interim Decision, June 2, 2000, at 9.

⁴⁰See *Matter of Athens*, *supra*; *Matter of Bowline*, *supra*, as well as Exhibits 144 and 145.

⁴¹See *Matter of Athens*, *supra*, citing *Hudson Riverkeeper Fund, Inc. v Orange & Rockland Utilities, Inc.*, 835 F. Supp. 160, 166 (SDNY 1993).

construction of the cooling water intake structure on fisheries resources are not at issue here.

Design features should reduce fish losses due to entrainment and impingement. Since the adverse impacts associated with entrainment mortality are directly related to the amount of water withdrawn, technology that sufficiently restricts or limits the capacity of a plant's water intake would be the best technology available. Capacity is at the center of the BTA dispute here.

Determining whether a particular technology represents BTA, requires a consideration of whether alternative technologies are available. Whether a particular technology is available is a question of fact to be determined on a case-by-case basis.⁴² Where alternative technologies are available, they should be analyzed to determine whether they constitute the best technology available for minimizing adverse environmental impacts.

After all the previously identified factors are considered, one final factor may be considered: cost. In 1977, the EPA Administrator approved a cooling water intake structure for a nuclear power plant in Seabrook, New Hampshire. The Administrator determined that other locations for the intake structures might slightly reduce impacts on smelt and flounder, but that the cost of relocating the cooling water intake structures would be "wholly disproportionate to the environmental benefit to be gained."⁴³ Upon review, the US Court of Appeals, First Circuit, found that costs were an acceptable consideration in determining whether a particular alternative intake design would be BTA. The court also referred to the Administrator's application of the "wholly disproportionate" standard and upheld the Administrator's approval of the intake structures for the Seabrook facility.⁴⁴

The wholly disproportionate standard is not a mere cost/benefit analysis. Rather, a finding must be made that the relative costs are wholly out of proportion with the environmental benefits to be gained. This standard gives

⁴²See *Hudson Riverkeeper Fund, supra*, at 166.

⁴³*In re Public Service Company of New Hampshire*, 10 ERC 1257 (1977), petition for review dismissed.

⁴⁴*Seacoast Anti-Pollution League v Costle*, 597 F2d 306, 311 (1st Cir. 1979).

presumptive weight to the value of environmental benefits, and places the burden on an applicant to demonstrate that the relative costs are unreasonable.⁴⁵

C. BTA Factors Relevant to the Facility

1. Potential Adverse Impacts

The threshold is low in considering whether any cooling water intake structure would cause adverse environmental impacts. Moreover, the hearing record concerning the DATEM issue shows that entrainment and impingement studies have been ongoing at the Facility for over 25 years. The results of these studies have established the weekly density of organisms in the Hudson River in the vicinity of the Facility. Although the results of these studies establish some entrainment survival, they also establish that not all aquatic organisms survive entrainment. Consequently, the Facility's cooling water intake structure causes adverse environmental impacts. As a result, the remaining questions must be addressed.

2. Design and Capacity

As part of the renewal application, Dynegy submitted an analysis of available technologies to reduce entrainment and impingement mortality. These included sonic deterrence and flow reduction. There were no substantive and significant issues for adjudication with respect to sonic deterrence.

Dynegy has agreed to install sonic deterrent equipment. Proposed Condition No. 10 of the revised draft SPDES permit would require Dynegy to deploy a high-frequency, high-energy sonic deterrent device at the mouth of the intake canal from August 1 through October 31 of each calendar year. Dynegy is also required to monitor the effectiveness of the device, and to submit reports to Department staff. (Exhibit 6, at 15 of 25.)

Sonic deterrent devices have successfully reduced the number of herring impinged at cooling water intakes. The sonic deterrent equipment that would be employed at the Facility would use a frequency targeted to repel juvenile American shad, Blueback herring and Alewife, which are three herring species that spawn in the Hudson River. The deployment time coincides with the period when juveniles of these species migrate down the

⁴⁵See *Matter of Athens*, *supra*, at 14-15.

river, and past the Facility, on their way to the ocean.
(Exhibit 3D.)

The amount of water used to cool the Facility relates to the capacity criterion. With respect to capacity, Dynegy has agreed to reduce cooling water withdrawals by limiting the number of pumps operating during periods when the ambient river temperature will allow reduced flow. To manage flow and to verify compliance with performance standards related to entrainment and impingement mortality, Dynegy would use DATEM. (Exhibit 6, Proposed Condition No. 11, at 15 of 25.) The factual issues concerning the accuracy of DATEM have been discussed above in § III. Based on the detailed hearing record, the baseline for DATEM should be calculated using full-flow. Credit should be given for entrainment survival based on the results of site-specific studies. Furthermore, the hearing record establishes that the temperature data from the City of Poughkeepsie water supply intakes are accurate.

In addition, revised draft SPDES permit Proposed Condition No. 13 would require Dynegy to study the feasibility of either installing an additional half capacity cooling water pump or retrofitting the existing pumps with variable speed motor controls at Unit 4. Depending on the results of the feasibility study, Dynegy would be required to implement one of the two pump options. (Exhibit 6, at 16 of 25.)

3. Practicable Alternative Technologies

For an existing electric generating facility, the number of practicable alternative technologies is limited. The seasonal installation of sonic deterrent equipment is a practicable alternative. Based on the hearing record, flow reduction is another available technology that would be verified with DATEM. The availability of half capacity and variable speed pumps was not at issue in the captioned matter, and has not yet been determined.

Retrofitting the Facility, either in whole or in part, with closed-cycle cooling towers would significantly reduce the amount of water needed to cool the Facility compared to the current once-through cooling system. One of the purposes of the hearing was to determine whether closed-cycle cooling towers would fit on the site. If closed-cycle cooling towers could fit on the site, then this technology could be considered a practicable alternative provided the cost of retrofitting and operating the Facility was not wholly disproportionate to the value of the

environmental benefit to be gained. The record shows, however, that the closed-cycle cooling tower retrofits proposed by Petitioners would not fit on the site. Consequently, this proposed technology is not available.

4. Wholly Disproportionate Costs

Dynegy has agreed to install sonic deterrent equipment at the Facility as conditioned by the revised draft SPDES permit. (Exhibit 6, Proposed Condition No. 10, at 15 of 25.) Therefore, the cost associated with this technology is not at issue.

In addition, Dynegy has agreed to implement a flow reduction and outage program as conditioned by the revised draft SPDES permit. To manage flow and to verify compliance with performance standards related to entrainment and impingement mortality, Dynegy would use DATEM. (Exhibit 6, Proposed Condition No. 11, at 15 of 25.) Consequently, the cost associated with this technology is not at issue.

With respect to the proposed retrofit configurations, the record shows that closed-cycle cooling towers would not fit on the site. As a result, this proposed technology is not available. Therefore, the cost associated with this technology need not be considered.

D. Conclusions

The following conclusions about the design and capacity of the Facility's cooling water intake structure are based on the preceding discussion. As discussed, the Facility's thermal discharges and its cooling water intake structure may result in adverse environmental impacts to the aquatic resources of the Hudson River. Therefore, consistent with the May 13, 2005 Interim Decision, the BTA standard outlined in 6 NYCRR 704.5, and as further developed in administrative decisional precedent, applies here.

Based on the full and complete record developed on this matter, I conclude that the seasonal sonic deterrent equipment, and flow reduction and outage program as presently required in the revised draft SPDES permit, meet the BTA standard outlined in 6 NYCRR 704.5. Sonic deterrent devices have successfully reduced the number of herring impinged at cooling water intakes. The sonic deterrent equipment that would be employed at the Facility would use a frequency targeted to repel juvenile American shad, Blueback herring and Alewife as they migrate down the river on

their way to the ocean. In addition, Dynegy has agreed to implement a flow reduction and outage program by actively managing flow and cooling water discharge temperature. To manage flow and to verify compliance with performance standards related to entrainment and impingement mortality, Dynegy would use DATEM.

As previously noted, the location and construction of the cooling water intake structure were not at issue in this proceeding. Finally, Dynegy has agreed to deploy the technologies presently required in the revised draft SPDES permit. Therefore, the costs associated with these technologies are not at issue.

Conclusion

The installation of seasonal sonic deterrent equipment, and the implementation of a flow reduction and outage program, as conditioned by the revised draft SPDES permit, would be the best technology available at the Danskammer Generating Facility for minimizing adverse environmental impacts (see 6 NYCRR 704.5).

Recommendations

1. The Deputy Commissioner should find that the closed-cycle cooling system retrofit configurations proposed by Petitioners would not fit on the site.
2. The Deputy Commissioner should find that the factual issues concerning the accuracy of DATEM have been resolved. The baseline for DATEM should be calculated using full-flow. Credit should be given for entrainment survival. The temperature data from the City of Poughkeepsie water supply intakes are accurate.
3. The Deputy Commissioner should conclude that the conditions in the revised draft SPDES permit for the Danskammer Generating Station are the best technology available for minimizing adverse environmental impacts.
4. The Deputy Commissioner should remand the matter to Department staff with instructions to issue the revised draft SPDES permit identified in the hearing record as Exhibit 6.

| | | |
|-------------|---|---|
| Appendixes: | A | Appearances of Counsel |
| | B | Witnesses |
| | C | Hearing Dates and Witnesses |
| | D | Chart Concerning Proposed Cooling Tower Configurations |

Appendix A - Appearances of Counsel

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Dynegy Northeast Generation, Inc.
Danskammer Generating Station
DEC No.3-3346-00011/00002
SPDES No.NY-0006262

Appendix B- Witnesses

For Dynegy Northeast Generation, Inc.

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Biologist 1
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Division of Fish, Wildlife and Marine Resources

Appendix C - Hearing Dates and Witnesses

November 15, 2005 (Transcript pages 1-120)

Prehearing Telephone Conference

November 16, 2005 (Transcript pages 121-452)

John M. Weidman
Ernest Neimi
David A. Schlissel
William Powers, P.E.

November 17, 2005 (Transcript pages 453-664)

William Powers, P.E.

November 18, 2005 (Transcript pages 665-846)

William Powers, P.E.

November 21, 2005 (Transcript pages 847-1039)

William Powers, P.E.

November 22, 2005 (Transcript pages 1040-1186)

David Harrison, Jr. Ph.D.

November 28, 2005 (Transcript pages 1187-1474)

William Powers, P.E.
As a panel: Matthew Allen, RLA
Michael C. Ascenzi, P.E.
Martin W. Daley
David B. Grogan
Wayne C. Michelitti

November 29, 2005 (Transcript pages 1475-1690)

As a panel: Michael C. Ascenzi, P.E.
Martin W. Daley
David B. Grogan
Wayne C. Michelitti

November 30, 2005 (Transcript pages 1691-1914)

As a panel: Michael C. Ascenzi, P.E.
Martin W. Daley
David B. Grogan
Wayne C. Michelitti

December 1, 2005 (Transcript pages 1915-2080)

David Harrison, Ph.D.

December 6, 2005 (Transcript pages 2081-2366)

Lawrence R. Wilson

December 12, 2005 (Transcript pages 2367-2616)

Peter A. Henderson, Ph.D.

December 13, 2005 (Transcript pages 2617-2898)

Peter A. Henderson, Ph.D.
As a panel: Lawrence W. Barnthouse, Ph.D.
Charles V. Beckers, Jr.
Charles C. Coutant, Ph.D.
Martin W. Daley
William P. Dey
Steven M. Jinks, Ph.D.
John R. Young, Ph.D.

December 14, 2005 (Transcript pages 2899-3071)

As a panel: Lawrence W. Barnthouse, Ph.D.
Charles V. Beckers, Jr.
Charles C. Coutant, Ph.D.
Martin W. Daley
William P. Dey
Steven M. Jinks, Ph.D.
John R. Young, Ph.D.

December 19, 2005 (Transcript pages 2899-3154 [sic])

As a panel: Michael C. Ascenzi, P.E.
Martin W. Daley
David B. Grogan
Wayne C. Michelitti

December 20, 2005 (Transcript pages 3155-3416)

Lawrence R. Wilson

December 22, 2005 (Transcript pages 3417-3571)

David Harrison, Ph.D.

Appendix D

PROPOSED RETROFIT COOLING TOWER CONFIGURATIONS
 Dynegy Northeast Generation, Inc.
 Danskammer Generating Station
 DEC No.: 3-3346-000011/00002 – SPDES No.: NY-0006262

| | Area 1 Between FAA Radio Beacon and Railroad Tracks | Area 2 Decommissioned Waste Water Treatment Lagoon (To be filled in) | Area 3 Intake Canal (To be filled in) | Area 4 West of Intake Canal (Site of One-Story Metal Warehouse) | Area 5 East Wall of Powerhouse | Area 6 South of Powerhouse | Area 7 West of Railroad Tracks |
|----------------------------------|---|--|---|---|--|--------------------------------------|--|
| Config. No. 1 | Units 1 or 2 (two wet cells) | Unit 3 (four wet cells) | Unit 4, and either Unit 1 or Unit 2 (eight wet cells) | | | | |
| Config. No. 2 | | Units 1 and 2 (four wet cells) | | Unit 3 (four wet cells) | | | Unit 4 (six wet cells) |
| Config. No. 3 | | | | Units 1 and 2 (four wet cells) | | Unit 3 (four wet cells) | Unit 4 (six wet cells) |
| Config. No. 4 | | | | Units 1 and 2 (four wet cells) | | Unit 4 (six wet cells) | Unit 3 (four wet cells) |
| Config. No. 5 | | Units 1 and 2 (four wet cells) | | Unit 3 (four wet cells) | | Unit 4 (six wet cells) | |
| Config. No. 6 | | Units 1 and 2 (four wet cells) | Unit 4 (six wet cells) | | | Unit 3 (four wet cells) | |
| Config. No. 7 | | | Units 1 and 2 (four wet cells) and Partial Unit 3 (two wet cells) | | Partial Unit 3 (six dry cells) | Unit 4 (six wet cells) | |
| Config. No. 8 | | | Unit 3 (six dry cells first set) | | Unit 3 (six dry cells second set) | Unit 4 (six wet cells) | Units 1 and 2 (four wet cells) |
| Config. No. 1 (Partial Retrofit) | | Unit 3 (four wet cells) | Unit 4 (six wet cells) | | | | |
| Config. No. 2 (Partial Retrofit) | | | | | | Unit 4 (six wet cells) | Unit 3 (four wet cells) |
| Config. No. 3 (Partial Retrofit) | | | | Unit 3 (four wet cells) | | Unit 4 (six wet cells) | |
| Config. No. 4 (Partial Retrofit) | | | | Partial Unit 3 (two wet cells) | Partial Unit 3 (six dry cells) | Unit 4 (six wet cells) | |