(11/18/14) Board Meeting
OTC Policy Special Studies
Deadline: 11/4/14 by 12:00 noon

Friends of the Earth

RECEIVED
11-3-14
SWRCB Clerk

Felicia Marcus, Board Chair
Frances Spivy-Weber, Board Vice Chair
Tam Doduc, Board Member
Steven Moore, Board Member
Dorene D'Adamo, Board Member
Water Resources Control Board
1001 I Street
Sacramento, CA 95814

November 3, 2014

Dear Members of the Water Resources Control Board,

In accordance with the statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, Friends of the Earth respectfully urges this Board to order PG&E to install cooling towers at its Diablo Canyon nuclear plant on the earliest feasible timetable.

Friends of the Earth retained Dr. William Powers, a recognized expert on cooling powers, to make an independent study of the feasibility and cost of installing cooling towers at Diablo Canyon (see attached and in the record of the Special Review Committee). That study is part of the evidence before you and we urge you to consider it as a truly independent assessment of the viability and cost of cooling towers. We say "truly independent" because the long history of mutual interest and collaboration between Bechtel and PG&E raises serious questions as to the motivation and collaboration between PG&E and Bechtel in the preparation and content of the Bechtel report.

This Board wisely established a committee that included state agencies other than the utility and its contractor that could provide the Board with an independent assessment of the control technologies and their costs. A number of independent members of the committee have considered all the evidence and reached the same conclusions as FOE, as follows.

"The Subcommittee of the Review Committee for Nuclear Fueled Power Plants (the Subcommittee) finds that there is no basis for an exemption from the once-through-cooling (OTC) Policy for Diablo Canyon Power Plant (Diablo Canyon). Based on the special study on alternatives to OTC for the state's nuclear facilities, the Subcommittee concludes that closed cycle cooling is a viable technology that could ensure Diablo Canyon's compliance with the state's OTC Policy. While there is a wide range of estimated costs associated with the closed cycle cooling technology, the Subcommittee believes that the only definitive way to determine the costs of retrofitting Diablo Canyon is for the utility to competitively bid the project with appropriate risk management and performance terms." (*)

On the issue of cost, the Powers/Friends of the Earth study (see attached), as well as a former study by Tetra Tech documents a one to two billion dollar cost. The inflated numbers in the Bechtel report for the same site reflect assumptions in cost that have been factually destroyed by the testimony of Dr. Powers.

There is a fundamental difference between the Bechtel study, the unwritten purpose of which is to show the largest cost, as compared to a company making a competitive bid to try to win the business. The Board has evidence before it, as well as the common sense insight, to conclude that the cost of cooling towers will be commensurate with the original estimates, and that the Board should not consider granting an exemption based on excessive cost as PG&E and Bechtel have sought to argue.

The FOE study also provides the Board with the independent expert testimony to make the following finding suggested by the independent members of the technical committee that we urge the Board to adopt:

"The fine mesh and wedge wire screen technologies assessed in the study do not appear viable despite having lower costs."(+)

Friends of the Earth wishes to remind the Board that the main reason utilities were given many years to comply with this policy was the concern six years ago about the reliability of the electric power system – in a word: blackouts. That fear is no longer controlling in light of the sizeable surplus of electric power capacity and the experience in closing San Onofre. a nuclear plant, the same size as Diablo, which abruptly shut and the lights stayed on. And Diablo, unlike San Onofre, is not needed for reliability purposes. There is ample generation and transmission capacity to replace it if it is shut down for cooling tower installation.

Therefore, Friends of the Earth strongly urges the Board to implement the statewide policy at Diablo Canyon: cooling towers should be installed, and in order to protect the marine environment, they should be installed on the fastest feasible timetable,

On behalf of Friends of the Earth, I thank you for your consideration of this important matter. Please do not hesitate to contact me if I can answer any further questions.

Sincerely,

Dan Moglen

Damon Moglen
Senior Strategic Advisor
Climate and Energy Program

Attachment: "Powers Engineering Response to Bechtel Final Addendum: Back to Back Seawater Cooling Tower Design/Cost for DCPP Units 1 and 2", October 30m 2014

(*)"Proposed Subcommittee Comments on Bechtel's Assessment of Alternatives to Once-Through-Cooling for Diablo Canyon Power Plant," September 12, 2014, p 1

(+) "Proposed Subcommittee Comments on Bechtel's Assessment of Alternatives to Once-Through-Cooling for Diablo Canyon Power Plant." September 12, 2014, p. 1

Powers Engineering Response to Bechtel Final Addendum: Back-to-Back Seawater Cooling Tower Design/Cost for DCPP Units 1 and 2

prepared for Friends of the Earth

Bill Powers, P.E., Powers Engineering, October 30, 2014

1. Executive Summary

The 34-cell ClearSky™ back-to-back plume-abated mechanical draft seawater cooling tower evaluated by Bechtel in its September 17, 2014 Final Addendum is the appropriate design for cooling tower retrofits at Diablo Canyon Power Plant (DCPP). Powers Engineering estimates the overall cost of seawater cooling tower retrofits on Units 1 and 2 at DCPP of approximately $1.2 billion. This estimated cost includes all costs related to the construction of the cooling towers ($500 million), the cost of replacement power during the outage necessary to tie-in the cooling towers to the existing DCPP circulating water ducts ($400 million), and a 30 percent contingency ($300 million).

The Bechtel cost estimate includes inflated and unnecessary costs. There is no technical necessity to drop the elevation of the cooling tower south parking area sites to 115 feet above sea level as proposed by Bechtel. Eliminating this unnecessary work reduces direct DCPP cooling tower construction costs in the Bechtel estimate by more than two-thirds, from $1.4 billion to about $400 million.

The forced construction outage of 2.3 years estimated by Bechtel for the cooling tower retrofit, with an associated replacement power cost of $1.9 billion, compares to the U.S. EPA estimate of the forced outage duration of a nuclear plant cooling tower retrofit from zero to 24 weeks. The replacement power cost for the worst-case EPA nuclear plant outage scenario, 24 weeks, would be about $400 million.

Bechtel's projected cost for the DCPP cooling tower conversion is $6.2 billion to $7.9 billion. This project cost is excessive. It is ten times or more the $660 million cost of the cooling tower retrofit at 1,500 MW Brayton Point Station (MA) completed in 2012. Powers Engineering concurs with the September 12, 2014 recommendations of the Subcommittee of the Review Committee for Nuclear Fueled Power Plants that the appropriate course of action is to move beyond the Bechtel cost estimate and put the DCPP cooling tower retrofit project out to competitive bid.

An optimized 34-cell cooling tower would impose a total efficiency penalty of about 6 percent compared to the existing once-through cooling (OTC) system on Units 1 and 2. This efficiency penalty should be partially offset by improved plant reliability. The conversion to closed-cycle cooling will eliminate two major reliability issues associated with the existing OTC system: 1) intake structure blockage by kelp and marine life, and 2) transformer arcing incidents caused in part by salt spray from the OTC outfall in front of the turbine building depositing on transformers downwind of the outfall and behind the turbine building.

Salt deposition at power plants using seawater cooling towers has proven to be manageable and has not led to reduce reliability. The seawater cooling towers at DCPP would be downwind of the turbine building and reactors in the prevailing wind direction, which would minimize salt deposition impacts.

2. Cooling towers are in common use on U.S. nuclear plants

About half of the U.S. nuclear power plant fleet is equipped with cooling towers.[1] Numerous proposed U.S. nuclear plants will be equipped with cooling towers, including seawater cooling towers.[2] Seawater cooling towers are in common use in the U.S. and around the world.[3] One U.S. nuclear plant, 800 MW Palisades Nuclear (MI), has been retrofit from once-through cooling to a cooling tower.[4]

3. High Bechtel cooling tower cost estimate is driven by technical error and unsupported indirect costs

The predominant direct cost in the September 17, 2014 Bechtel Final Addendum associated with cooling tower construction, $1 billion of the $1.4 billion, is based exclusively on the erroneous assumption that the base elevation of the cooling towers cannot exceed 115 feet MSL. This $1 billion in civil works expenses is eliminated if the cooling towers are located on the proposed sites without modification to the elevation of those sites. Bechtel's $383 million installed cost for Unit 1 and Unit 2 ClearSky™ cooling towers, pumps, piping, electrical/ instrumentation, and traffic/logistics, excluding the $1 billion civil works cost line item, is reasonable and consistent with other comparable estimates.

A major deficiency of the Bechtel cost estimate is the inclusion of huge ancillary costs with either no substantive explanation or an explanation that does not support the stated cost. For example, the $1.369 billion Bechtel estimates for housekeeping, tool room management, and internet, among other seemingly minor activities, is so out-of-proportion to the core project cost that it calls into question the seriousness of the overall cost estimation exercise.[5]

In addition to the Bechtel Final Addendum, several other cooling tower retrofit cost estimates have been prepared for California's two nuclear plants, DCPP and SONGS. One contractor, Enercon, prepared cooling tower retrofit cost estimates for DCPP and SONGS in 2009 under

---

[1] U.S. EPA, *Technical Development Document for the Final Section 316(b) Existing Facilities Rule,* May 2014, Exhibit 4-10, p. 4-9.
[2] Plant Vogtle (GA) Units 3&4 (under construction), Virgil Summer (SC) Units 2&3 (under construction), Turkey Point (FL) Units 6&7 (proposed, seawater).
[3] Bechtel, *Feasibility of Seawater Cooling Towers for Large-Scale Petrochemical Development*, 2003, Table 7, p. 17.
[4] U.S. EPA, *Technical Development Document for the Final Section 316(b) Existing Facilities Rule,* May 2014, p. 5-4.
[5] Bechtel Final Addendum, Table 6.3.1-1, p. 39 and p. 41, September 17, 2014.

contract to PG&E and SCE, respectively. DCPP and SONGS are the same capacity.[6] The Enercon installed cost estimate at SONGS was $386 million for plume-abated cooling towers, pumps, and piping, and $106 million for design engineering, construction, installation, and field testing.[7] The total estimated cost estimated by Enercon for the SONGS cooling tower retrofit is the sum of these two costs, $492 million (not including contingency).

Where Enercon estimates $106 million in indirect costs at SONGS, Bechtel estimates $1.8 billion in indirect costs at DCPP with almost no explanation. This aspect of the Bechtel cost estimate is not credible.

In contrast, the Enercon installed plume-abated cooling tower cost of $492 million for SONGS is also a reasonable cost estimate for a ClearSky™ plume-abated cooling tower retrofit at DCPP.[8]

4. There is no technical need to reduce the elevations of the proposed Unit 1 and 2 cooling tower sites

Bechtel's presumption that the existing elevation of the proposed cooling tower sites must be reduced, from 135 feet MSL and 131 feet MSL to an elevation of 115 feet MSL, is technically flawed. The existing circulating water ducts are designed for 50 psig service (115 feet hydraulic pressure).[9] The Unit 1 and 2 surface condensers will be upgraded from 25 psig to 50 psig as a component of the cooling tower retrofit project.[10] The low point in the existing water ducts is 43 feet MSL located underground in front of the DCPP turbine building. The turbine building is shown in Figure 1.

---

[6] The net DCPP capacity is 2,150 MW. The net SONGS capacity was 2,200 MW prior to the permanent retirement of SONGS in June 2013.

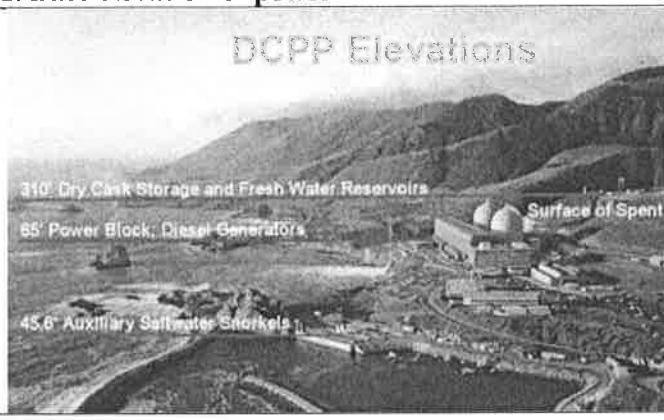
[7] The Enercon March 2009 DCPP cost estimate is more four times higher, at $2.241 billion, than the Enercon cost estimate of $492 million for the SONGS cooling tower retrofit. DCPP and SONGS are the same capacity. Enercon completed the cost estimates for DCPP and SONGS in the same year, 2009. The Enercon DCPP cost estimate is based on two descriptive paragraphs and numerous cost tables. However, the equipment costs identified by Enercon for the DCPP and SONGS cooling tower retrofits are essentially the same at $248 million and $263 million, respectively. The equipment cost-to-installed cost ratio in the Enercon SONGS estimate is approximately 2-to-1. The ClearSky™ cooling tower manufacturer, SPX, identifies a typical ClearSky™ cooling tower equipment cost-to-installed cost ratio of approximately 2-to-1. The Enercon DCPP cooling tower cost estimate has an equipment cost-to-installed cost ratio of nearly 10-to-1. The Enercon DCPP cooling tower retrofit cost estimate is not considered credible by Powers Engineering for two reasons: 1) it is dramatically higher than the typical expected cost projected by the cooling tower manufacturer with no compelling justification for the much higher cost, and 2) it is dramatically higher than the cooling tower retrofit cost projected by the same consultant (Enercon) for the same sized nuclear plant (SONGS) in the same year (2009) that is consistent with the typical expected cost projected by the ClearSky™ cooling tower manufacturer.

[8] Enercon is a PG&E contractor that conducted cooling tower retrofit studies at DCPP and SONGS in 2009. Enercon evaluated plume-abated cooling towers at SONGS, and conventional cooling towers at DCPP. Little civil work beyond the cooling tower circulating water piping and cold water basin were anticipated by Enercon for the SONGS retrofit. In contrast, Enercon assumed nearly $1 billion in additional civil work at DCPP. For these reasons, the Enercon estimate for the SONGS cooling towers is the most comparable estimate for a ClearSky™ plume-abated cooling tower retrofit in the DCPP south parking area with no modification to the elevation of the cooling tower sites.

[9] Bechtel Final Addendum, September 17, 2014, p. 10.

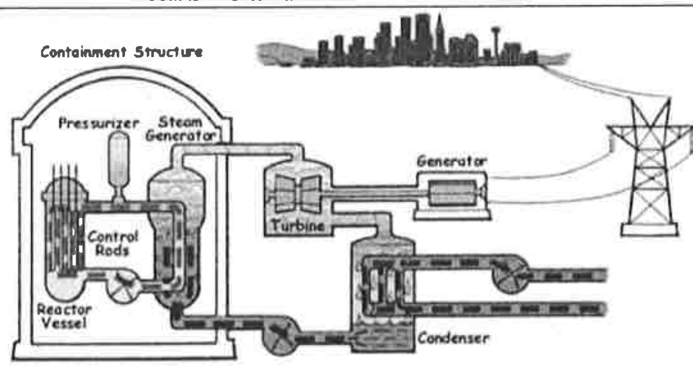
[10] Ibid.

Figure 1. Base elevation of power block in DCPP turbine building[11]



The generic location of the surface condensers under the steam turbines is shown in Figure 2.

Figure 2. Schematic of nuclear plant power generation cycle showing location of steam turbine and surface condenser[12]



The existing circulating water ducts and upgraded surface condensers can withstand 115 feet of hydraulic pressure applied to the base duct elevation of 43 feet MSL, equivalent to a total elevation of 43 feet MSL + 115 feet = 158 feet MSL.

This is more than sufficient to withstand the hydraulic pressure generated by the proposed 135 feet MSL (Unit 2) and 131 feet MSL (Unit 1) unmodified cooling tower elevations. A graphical presentation of Bechtel's 34-cell cooling tower alternative is provided in **Attachment A, Figure A-1,** showing the location of the 43 feet MSL low point in the existing circulating water ducts and the proposed locations and elevations of the Unit 1 and 2 cooling towers.

There is no technical need to lower the elevation of the proposed cooling tower locations to 115 feet MSL to protect either the existing circulating water ducts or the upgraded Unit 1 and 2 surface condensers from overpressure.

[11] NRC DCPP fact sheet, March 22, 2011: http://pbadupws.nrc.gov/docs/ML1112/ML111290158.pdf.
[12] NRC webpage, the pressurized water reactor, updated March 2012: http://www.nrc.gov/reading-rm/basic-ref/students/animated-pwr.html.

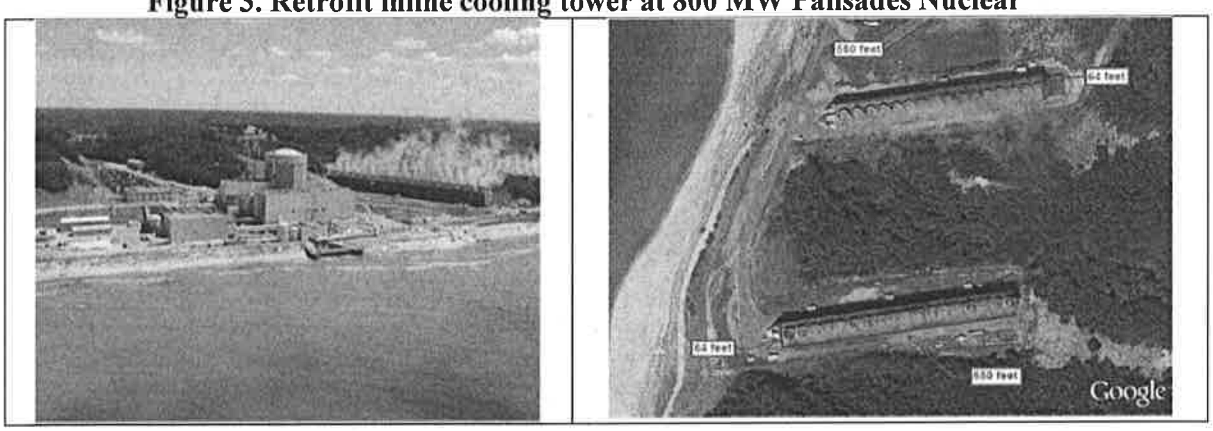
5. DCPP cooling tower retrofit project can be completed within 4-5 years of permit application date at far less cost than projected by Bechtel

The Unit 1 and 2 cooling tower retrofits can be completed in 4 to 5 years from the time of the submittal of the permit application to initial operation, not the 13.8 years estimated by Bechtel. Several utility-scale solar projects, covering thousands of acres of undeveloped land, and with substantial impacts on endangered species, have been permitted in one year in California.[13] In contrast, the DCPP south parking lot cooling tower retrofit project would take place exclusively on previously developed land. The purpose of the project would be to reduce impacts on marine species. Priority projects in California have repeatedly been permitted in one year.

The timeline to go from approved permit to operational retrofit cooling tower(s) at U.S. nuclear and large non-nuclear plants that have been retrofit to cooling tower(s) has been three years or less. A 4- to 5-year timeline from the filing of an application to construct to initial operation of the DCPP cooling towers is reasonable in the context of actual permit timelines for priority projects in California and actual cooling tower retrofit construction timelines.

800 MW Palisades Nuclear (Michigan, one unit) began procurement and construction of a retrofit cooling tower in mid-1971. The conventional (no plume abatement) inline mechanical draft tower was operational in mid-1974, three years after procurement of equipment for the cooling tower retrofit began. The Palisades Nuclear cooling tower, consisting of two sections, is shown in Figure 3. The cost of the Palisades Nuclear cooling tower retrofit was $55.9 million (adjusted to 1999 dollars).[14]

Figure 3. Retrofit inline cooling tower at 800 MW Palisades Nuclear[15,16]



---

[13] California Energy Commission, Large Solar Energy Project webpage, see permit timelines for Abengoa Mojave Solar Project, Blythe Solar Project, and Genesis Solar Project: http://www.energy.ca.gov/siting/solar/

[14] U.S. EPA, *Technical Development Document (TDD) for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002. Chapter 4, *Cooling System Conversions at Existing Facilities*, p. 4-5 and p. 4-6.

[15] NRC webpage, Palisades Nuclear Plant: http://www.nrc.gov/info-finder/reactor/pali.html .

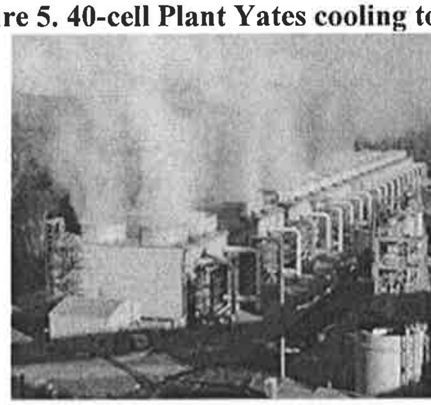
[16] Google Earth photograph, tags added by B. Powers.

More recently, a 36-month timeline was set in the EPA compliance order for conversion of Dominion Energy's 1,500 MW Brayton Point Station (Massachusetts, coal plant) to cooling towers.[17] Dominion finalized all permits for the cooling tower retrofit in March 2009.[18] Construction of the two hyperbolic natural draft cooling towers began in May 2009.[19] Both cooling towers were operational by May 2012.[20] These two cooling towers are shown in Figure 4. The total cost of the Brayton Point cooling tower retrofit was $660 million (2011 dollars).[21]

Figure 4. Retrofit cooling towers at 1,500 MW Brayton Point Station[22]

A 40-cell back-to-back retrofit conventional (no plume abatement) cooling tower was retrofit at Georgia Power's Plant Yates (GA) between 2001 and 2004. Groundbreaking took place in May 2001 and the retrofit was completed in February 2004.[23] The total project cost was $83 million (2004 dollars).[24] The Plant Yates cooling towers is shown in Figure 5.

Figure 5. 40-cell Plant Yates cooling tower[25]



[17] EPA Brayton Point Station 316(b) compliance homepage: http://www.epa.gov/region1/braytonpoint/. "EPA has issued an administrative order containing a schedule for meeting all NPDES permit limits within 36 months of obtaining all of the required construction and operating permits and approvals."
[18] Fall River (MA) Herald News, *Plant moving forward with cooling towers*, April 6, 2009.
[19] Power Engineering (magazine), *Retrofit Options to Comply with 316(b)*, October 1, 2010.
[20] D. Houlihan – EPA Regional 1, EPA Engineering Project Manager – Brayton Point Station cooling tower conversion, e-mail to B. Powers, October 27, 2014.
[21] D. Houlihan – EPA Regional 1, EPA Engineering Project Manager – Brayton Point Station cooling tower conversion, e-mail to B. Powers, December 1, 2011.
[22] Dominion Power (former owner) Brayton Point Power Station webpage, 2012 (no longer operational).
[23] D. Houlihan – EPA Region 1, *Phone Memorandum – Conversion of Two Coal-Fired Power Plants Located Owned (sic) by Georgia Power*, January 7, 2003.
[24] T. Cheek - Geosyntec Consultants, Inc. and B. Evans – Georgia Power Company, *Thermal Load, Dissolved Oxygen, and Assimilative Capacity: Is 316(a) Becoming Irrelevant? – The Georgia Power Experience*, presentation to the EPRI Workshop on Advanced Thermal Electric Cooling Technologies, July 8, 2008, p. 18.
[25] Ibid.

There is no technical or administrative reason that the environmental permitting of the DCPP cooling tower conversion project should take any longer than the year-long environmental permitting of utility-scale solar thermal projects. A one-year environmental review and approval process, combined with a construction timeline from the date of an approved permit to the completion of construction of 3 to 4 years, represents an overall project timeline of 4 to 5 years.

Actual large-scale cooling tower retrofit projects have been completed for a small fraction of the $6.2 billion to $7.9 billion cost that Bechtel estimates for the 34-cell cooling tower retrofit alternative.[26] The most comparable project is the 1,500 MW Brayton Point Station cooling tower retrofit completed in May 2012. The Brayton Point Station retrofit was approximately two-thirds the scale of the proposed DCPP retrofit. However, the $660 million project cost is about one-tenth or less the cost projected by Bechtel for the DCPP cooling tower retrofits.

The Subcommittee of the Review Committee for Nuclear Fueled Power Plants is correct to recommend in its September 12, 2014 letter to the SWRCB (p. 11) that the DCPP cooling tower retrofit project to be put out to competitive bid. It is the opinion of Powers Engineering that bids based on sound engineering principles and innovative adaptation to the existing south parking lot terraces will result in bids much closer to the $660 million cost of the Brayton Point Station cooling tower retrofit project than to the Bechtel $6.2 billion to $7.9 billion estimate.

6. Outage for hook-up of cooling tower piping may be as little as one month, not 2.3 years

There is no technical justification for the 2.3 year dual outage projected by Bechtel for cooling tower retrofits at DCPP. PG&E carried-out complex steam generator retrofits on Units 1 and 2 in 2008 and 2009. These retrofits required cutting large openings in the nuclear containment domes, removing the four original steam generators, installing replacement steam generators, and resealing the containment dome. This entire process was carried-out in two to two-and-a-half months on each unit.

The downtime required for piping hook-ups at U.S. power plants that have been retrofit to cooling towers has generally been one month or less. Units 1 and 2 undergo 30- to 45-day refueling outages approximately every two years. An unscheduled outage of one month beyond the duration of the refueling outage is equivalent to the total outage time, two to two-and-a-half months, required by PG&E to do the substantially more complex steam generator retrofits on Units 1 and 2.

The Unit 1 and 2 steam generator replacement project is an example of a major and very invasive construction project, within the nuclear safety area at DCPP, being carried-out with only a short forced outage. The four steam generators at Unit 2 were replaced in 2008 with a total outage time of 69 days. The Unit 1 steam generators were replaced in early 2009 in 58 days.[27] The work was done concurrently with planned refueling outages in both cases. Refueling outages generally occur on one-and-a-half to two-year intervals.

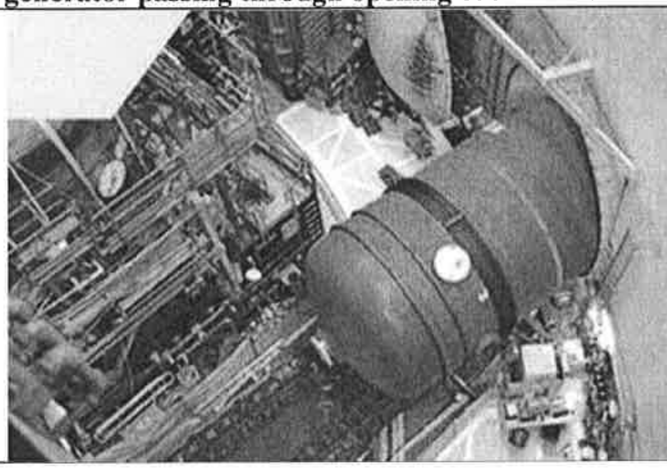
---

[26] Bechtel Final Addendum, September 1, 2014, Table 1.2-1, p. 8, Case 1B (34-cell).

[27] Power Engineering, *Diablo Canyon Unit 1 Steam Generator Replacement Project*, September 1, 2009.

Since the containment building and original installation of the Unit 1 and 2 steam generators was not intended to provide easy replacement, a completely customized system and innovative assembly process were needed to remove them. A photograph of a Unit 1 replacement steam generator moving through the Unit 1 containment dome hatch is shown in Figure 6.

Figure 6. Steam generator passing through opening cut in Unit 1 containment dome[28]



There is no technical reason that the hook-up of cooling tower piping to the existing circulating water ducts, and upgrading of the existing surface condensers - the only two construction activities associated with the cooling tower retrofit that require Units 1 and 2 to be offline - should require an extended outage. The U.S. EPA estimates a one-month net outage for retrofit cooling tower hook-up at conventional fossil fuel plants of any size.[29] TetraTech estimates a six-week net outage for retrofit cooling tower hook-up at conventional fossil fuel plants of any size.[30] EPA assumes no outage time is necessary for a cooling tower retrofit at nuclear plants that are undergoing a concurrent extended capacity uprate outage that typically lasts 2 to 4 months,[31] and an average net outage of 24 weeks otherwise.

All construction activity associated with retrofit cooling towers at DCPP will take place outside the nuclear safety area. There is no nuclear hazard basis for an extended outage.

The 2.3 year concurrent outage at DCPP for the cooling tower retrofit projected by Bechtel, and the associated $1.9 billion replacement power cost, has no support in the September 20, 2013 Draft Report or the September 17, 2014 Final Addendum. Bechtel has identified no construction

[28] Ibid.

[29] U.S. EPA, *Technical Development Document for the Final Section 316(b) Existing Facilities Rule*, May 2014, p. 8-33. "The assumed net downtime for non-nuclear power plants remains 4 weeks."

[30] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, February 2008, p. 5-12. "This study conservatively assumed a construction-related shutdown of six weeks for most of the fossil fuel facilities."

[31] U.S. EPA *Technical Development Document for the Final Section 316(b) Existing Facilities Rule*, May 2014, p. 8-34. "EPA assumed that (nuclear) facilities performing an ECU would be capable of completing the (cooling tower) retrofit concurrently with the ECU and that the scope of the ECU would be extensive enough to push the duration toward the longer end of the 2 to 4 month or longer range. For these projects, EPA assumed zero downtime (for the cooling tower conversion)."

activities that require a shutdown to carry-out other than tie-in of cooling tower piping to existing circulating water ducts and the surface condenser upgrade. These are short duration activities that can be accomplished in days (surface condenser upgrade)[32] or weeks (piping tie-in). The approximate outage time for the 1,500 MW Brayton Point Station cooling tower upgrade, completed in May 2012, was approximately four weeks.[33]

A one-month unplanned outage per unit is the most likely scenario for replacement power cost estimation purposes, not 2.3 years per unit. A worst-case scenario is a 24-week unplanned outage per unit. The total replacement power cost for a 24-week unplanned outage would be approximately $400 million.[34]

7. 34-cell ClearSky cooling towers fit in existing, unmodified parking areas

The cooling towers are more compact than indicated by Bechtel. Bechtel erroneously identifies the cooling tower cells in its ClearSky™ cooling tower as 60 feet (W) by 56 feet (L).

Cooling tower cells can be configured in a variety of dimensions. For example SPX, the manufacturer of the ClearSky™ cooling tower technology, provided Bechtel with a specification for relatively compact cooling tower cells with a width of 54 feet (W) and length (L) of 42 feet. However, Bechtel misidentifies the dimensions of the cooling towers in the Final Addendum.[35] Bechtel identifies the cooling tower cells as having dimensions of 60 feet W by 56 ft L, and uses these cell dimensions in its engineering drawing of the 34-cell cooling tower(s) layout (**Attachment A, Figure A-1**) and in the photo simulation of the cooling tower layout (**Figure A-3**).

The manufacturer's model number for the design used by Bechtel is F497.[36] The F4 designation signifies the type of cooling tower design used. The "9" signifies 54 feet. The "7" signifies 42 feet.[37] The F497 designation means each cell measures 54 feet (W) by 42 feet (L).

The manufacturer's specification provided by SPX to Bechtel identifies the cooling tower cells as having dimensions of 54 feet W by 42 feet L. When the correct cell dimensions are utilized, as

---

[32] U.S. EPA, *Technical Development Document (TDD) for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002. Chapter 4, *Cooling System Conversions at Existing Facilities*, p. 4-9: "The Agency located a reference for a project where four condenser waterboxes and tube bundles were removed and replaced at a large nuclear plant (Arkansas Nuclear One). The full project lasted approximately 2 days."
[33] D. Houlihan – EPA Regional 1, EPA Engineering Project Manager – Brayton Point Station cooling tower conversion, e-mail to B. Powers, October 27, 2014.
[34] Bechtel Final Addendum, p. 50 (revised calculation assuming 24 week outage): 1,155 MW × 24 hours × 168 days × $46.76 MWh × 2 units × 0.9 capacity factor = $391,967,000.
[35] Bechtel Final Addendum, September 17, 2014, p. 12.
[36] D. Dismukes – Bechtel, e-mail to B. Powers and J. Bishop regarding ClearSky™ cooling tower designs for DCPP Units 1 and 2 provided by SPX, January 21, 2014. Cooling tower model number is F497DB-6.6-22B (2×11). F497 translates to F400 series cooling tower cell, "9" is cell width of 9 × 6 feet = 54 feet, "7" is cell length of 7 × 6 feet = 42 feet. "6.6" is the depth of the fill material in feet.
[37] The manufacturer, SPX, provides length and width in six-foot increments in its cooling tower model numbers. "9" means 9 × 6 feet = 54 feet, and "7" means 7 × 6 feet = 42 feet.

shown in **Attachment A, Figure A-2**, the Unit 1 and 2 cooling towers are substantially more compact than indicated by Bechtel and fit in existing unmodified parking areas.

Candidate sites proposed by Powers Engineering for the Unit 1 and Unit 2 ClearSky™ cooling towers in these parking areas are shown in Figures 7 and 8. These locations are also shown as overlays on the Bechtel 34-cell cooling tower graphic in **Attachment A, Figure A-2**. The Bechtel 34-cell design, when the correct dimensions of the specified cooling tower cells are used, is significantly shorter than the 34-cell optimized design evaluated by Powers Engineering and fits more easily in available parking areas. The 34-cell Bechtel cooling towers, using the correct cooling tower dimensions as provided by manufacturer SPX, are also shown as overlays in Figures 7 and 8 for comparative purposes.

Figure 7. Recommended placement of Unit 1 cooling tower using actual tower dimensions[38]

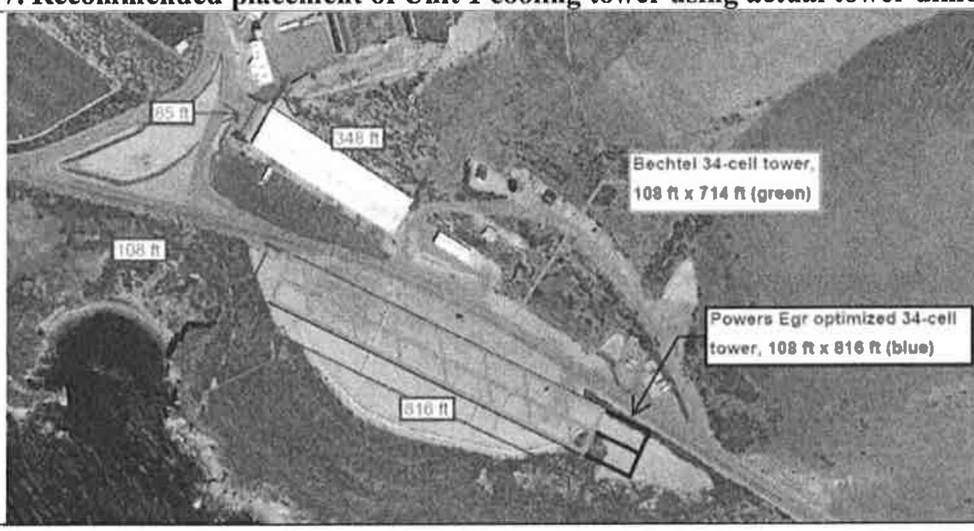
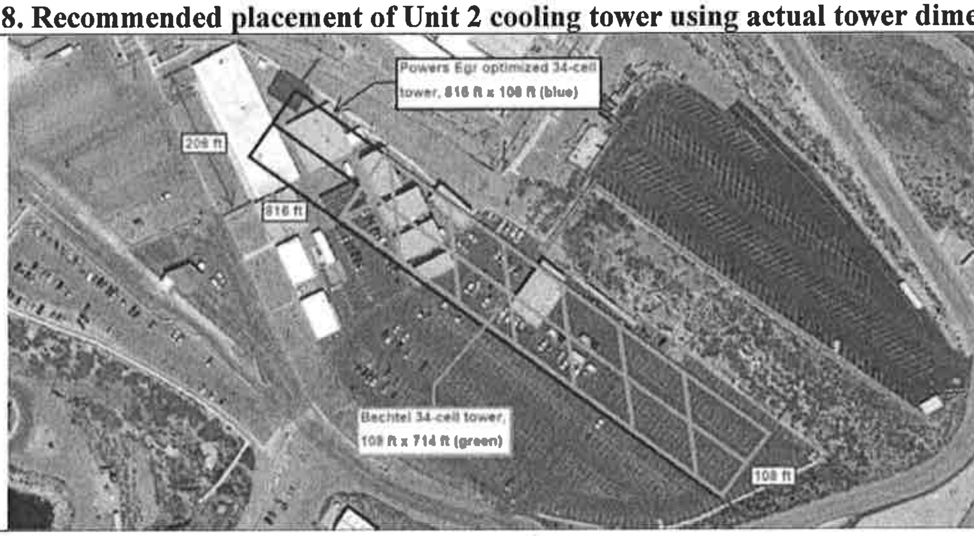


Figure 8. Recommended placement of Unit 2 cooling tower using actual tower dimensions[39]



[38] Google Earth photograph, tags and line drawings by B. Powers.
[39] Google Earth photograph, tags and line drawings by B. Powers.

Using the correct dimensions of the 34-cell ClearSky™ cooling tower, and constructing at the existing unmodified elevations of the south parking lot candidate sites, largely eliminates Bechtel's justification for demolishing/relocating onsite structures, as shown in Figure 2. Only seven relatively small structures (~18,000 square feet total), identified as "temporary structures" in the 2008 TetraTech cooling tower retrofit study for DCPP, would need to be relocated to another part of the Unit 2 cooling tower parking area. A 15-foot wide buffer around the cooling towers is sufficient to provide maintenance access for vehicles and cranes.

8. Efficiency penalty imposed by cooling tower retrofit is reasonable, and conversion provides reliability benefits

Steam-turbine generator efficiency penalty: A summary of the steam-turbine generator efficiency penalty of an optimized ClearSky™ 34-cell back-to-back cooling tower design for DCPP Units 1 and 2, using 54 feet (W) by 48 feet (L) cooling cells and a 600,000 gpm circulating cooling water flowrate, is provided in **Attachment B**. A cooling tower flowrate of approximately 600,000 gpm is typically specified for new reactors with a heat rejection requirement equivalent to DCPP Units 1 and 2.[40] The efficiency penalty of this alternative 34-cell design would be less than 4 inches mercury at design conditions. The annual average efficiency penalty of this design, due to higher backpressure on the steam turbine-generator, would be approximately 5.8 percent, or about 64 MW.

Change in pump power demand: There should be a reduction in pumping power requirements following the conversion from the existing OTC system to retrofit cooling towers, assuming a circulating cooling tower flowrate of 600,000 gpm. Bechtel incorrectly states there will an increase in the pump power requirement by 12.4 MW per unit (16,700 hp).[41] The existing OTC circulating water pumping power requirement is 26,000 horsepower per unit at DCPP.[42] The pumping power required to move 600,000 gpm through a ClearSky™ retrofit cooling tower at the 131 feet MSL unmodified Unit 1 cooling tower site proposed by Bechtel would be about 22,800 hp.[43] The cooling tower pumping load would be about 2.4 MW (3,200 hp) less than the existing OTC pumping load per unit.

Cooling tower fan power demand: Bechtel estimates a fan power demand of 7.1 MW for the 34-cell ClearSky cooling tower. This fan power estimate is accurate.

---

[40] Examples include: Vogtle 3 & 4, Georgia (under construction), V. Summer 2 & 3, South Carolina (under construction), Turkey Point 6 & 7, Florida, and Levy 1 & 2, Florida.

[41] Bechtel Final Addendum, September 17, 2014, p. 8.

[42] PG&E Letter DCL-10-124, *Information to Support NRC Review of DCPP License Renewal Application (LRA) Environmental Report – Operating License Renewal Stage*, October 27, 2010, p. 2-8.

[43] Assumptions: pump inlet elevation = 51 feet MSL. Height of cooling tower cold water basin = 131 feet MSL. Pump head requirement per SPX = 35 feet. Assume friction losses = 10 feet. Pump/motor efficiency = 83 percent (per Johnston Pumps and GE Motors & Industrial Systems 2003 quotes). Therefore total pump head requirement = (131 feet + 35 feet + 10 feet) – 51 feet = 125 feet. Pump power requirement (hp) = [(600,000 gpm) (125 feet)]/[(3,960)(0.83)] = 22,820 hp. Powers Engineering recommends that the Unit 2 cooling tower be located on the unmodified123 feet MSL parking lot terrace directly below the 135 feet MSL terrace where Bechtel has sited the Unit 1 cooling tower. See **Attachment A, Figure A-2**. The Unit 2 cooling tower at the 123 feet MSL elevation will have a lower pump power requirement than the Unit 1 cooling tower at the unmodified 131 feet MSL elevation.

The total efficiency penalty of the 34-cell cooling tower conversion per unit would be: 64 MW – 2 MW + 7 MW = 69 MW. This represents a total efficiency penalty of about 6 percent.[44]

The reliability benefit of eliminating unit shutdowns caused by intake structure blockage and OTC outfall sea spray deposition on the Unit 2 transformers is not reflected in the efficiency penalty calculation.

DCPP plant staff identified blockage of the cooling water intake structure(s) as the primary plant reliability challenge of the OTC design.[45] The capacity factors for Units 1 and 2 in each unit's most recent non-refueling year, 98.2 percent in 2013 (Unit 1) and 96.5 percent in 2012 (Unit 2), were on average about 3 percent below the baseline 100 percent target which both units have achieved in the past. It is not known how much of this downtime was related to intake structure blockage. Intake structure blockage will no longer cause outages following the conversion to cooling towers.

The Diablo Canyon Independent Safety Committee (DCISC) issued an October 7, 2014 preliminary final report regarding the safety implications of seawater cooling towers that documented three recent arcing events at the Unit 2 transformer bank adjacent to the turbine building caused in part by the accumulation of salt spray from the OTC outfall on the transformers. The concern expressed by the DCISC was that additional salt deposition from seawater cooling towers could exacerbate these types of events.

However, the information provided in the October 7, 2014 DCISC document underscores the potential benefit of a conversion to seawater cooling towers in the southern parking lot locations. DCISC explains how the Unit 2 transformers have been a reliability weak point due to being subject to salt spray generated in the OTC outfall that is driven by the prevailing northwest-to-southeast wind pattern around the southeast end of the DCPP turbine building and into the Unit 2 transformer location.

In contrast, the Unit 1 transformers are subject to much less salt deposition because they are located around the northwest end of the turbine building and salt spray from the OTC outfall would infrequently be driven in that direction. Consequently, Unit 1 transformer trips due to salt deposition on the transformers and transformer insulators have not been a reliability issue.

The source of the salt deposition problem on the Unit 2 transformers is the salt spray from the OTC outfall. The OTC outfall will be decommissioned when DCPP converts to seawater cooling towers. Therefore, the current source of the salt deposition problem will be eliminated.

[44] 100 × (69 MW/1,100 MW) = 6.3 percent.

[45] PG&E staff comments at April 8, 2014 Nuclear Review Committee meeting, held at State Water Resources Control Board headquarters, Sacramento, California.

9. Air emission offsets can be obtained to offset seawater cooling tower salt drift emissions

Powers Engineering concurs with Bechtel that particulate emissions from the cooling towers can be offset by paving dirt roads in San Luis Obispo County, and that the cost of this road paving effort would be modest, on the order of $10 million or less.

New closed-cycle cooled nuclear units in the U.S. that have the same heat removal load as DCPP Units 1 and 2 have circulating water flowrates ranging from 600,000 to 631,000 gpm. DCPP cooling tower optimization should include reducing cooling water flow from 868,300 gpm to 600,000 gpm. This reduction in circulating water flowrate will also reduce particulate emissions from the cooling towers proportionately.

10. Seawater cooling tower salt deposition will not negatively impact plant reliability

Powers Engineering concurs with Bechtel's statement in the Final Addendum (p. 5) that:

> "*The saltwater drift from the cooling towers would necessitate an additional maintenance effort by the plant staff to keep plant equipment clean. Note that during most of the year, the wind direction in this area is away from the power block, which would minimize this impact.*"

Saltwater drift from the proposed seawater cooling towers is manageable within the confines of DCPP's existing operations and maintenance program and may be minimal given the prevailing wind patterns at DCPP.

The California Energy Commission (CEC) contracted for an analysis of the performance of salt water cooling towers in 2010. The report lists 58 power plants in the U.S. and other countries that utilize either seawater or brackish water cooling towers.[46] Two of the installations listed were commissioned by Bechtel. In addition, Bechtel published a list of over 30 seawater cooling tower installations worldwide in a 2003 technical paper highlighting the benefits of seawater cooling towers. See **Attachment C**.

The fact that many plants have been operating successfully, in some cases for over three decades, with seawater cooling towers or with brackish water cooling towers where the circulating water in some cases approaches the total dissolved solids ("salt") concentration of seawater, is clear evidence that concerns regarding the potential for increased arcing across onsite high voltage insulators can be effectively managed.

For example, the authors of the CEC-commissioned study of salt water cooling towers conducted site visits to selected plants to assess the performance and impacts of salt water cooling towers.

---

[46] J. Maulbetsch, M. DiFilippo, *Performance, Cost, and Environmental Effects of Saltwater Cooling Towers – PIER Final Consultant Report*, prepared for California Energy Commission, January 2010, Table 4-1, Saltwater Tower Installations, pp. 18-21.

The effect on insulator arcing of onsite salt water cooling towers was addressed during the visit to the St. John's River Park power plant in Jacksonville, Florida. Plant personnel stated that, "*Salt deposits on switchyard insulators have led to arcing problems. These are minimized through the use of larger insulators and insulators made of polymer-based material or silicone-coated porcelain.*"[47]

The predominant wind pattern at DCPP is northwest-to-southeast. See the DCPP wind rose in **Attachment A, Figure A-1**. This predominant wind pattern would carry salt drift from the cooling towers, which would be located to the southeast of the turbine building, away from electrical equipment in the vicinity of the turbine building.

U.S. nuclear plants have operated successfully for decades adjacent to seawater or saltwater cooling towers. Example nuclear plants include 860 MW Crystal River Nuclear Unit 3, 3,957 MW Palo Verde Nuclear Units 1-3, and 1,172 MW Hope Creek Nuclear.

Crystal River Nuclear Unit 3: The once-through cooled 860 MW Crystal River Nuclear Unit 3, which began operation in 1977 north of Tampa on the west coast of Florida, is collocated with multiple coal-fired steam units. Nuclear Unit 3 underwent a steam generator replacement in 2009 and suffered damage during the project.[48] The unit was permanently shut down in 2013.[49] The permitted salt drift emission rate of onsite Crystal River seawater cooling towers is the sum of salt drift from the helper cooling towers and the Unit 4 and 5 hyperbolic cooling towers. The annual salt drift air permit limit for all onsite seawater cooling towers = 925 tpy + 767 tpy = 1,692 tpy. See **Attachment D**. This is approximately double the projected salt drift emissions from the DCPP Unit 1 and 2 seawater cooling towers.

Powers Engineering compared the Crystal River Nuclear Unit 3 average capacity factor for the ten years prior to its 2009 steam turbine replacement project to similar 10-year period for DCPP Units 1 and 2 to determine if the high amount of salt drift at Crystal River was reflected in poorer reliability. In fact, Crystal River Nuclear Unit 3 achieved a significantly higher capacity factor, 93.2 percent, during the 10-year period evaluated, than either DCPP Unit 1 or 2, at 90.0 and 91.2 percent, respectively.[50] Exposure to high levels of salt deposition at was not reflected in lower reliability at Crystal River Nuclear Unit 3 compared to DCPP Units 1 and 2.

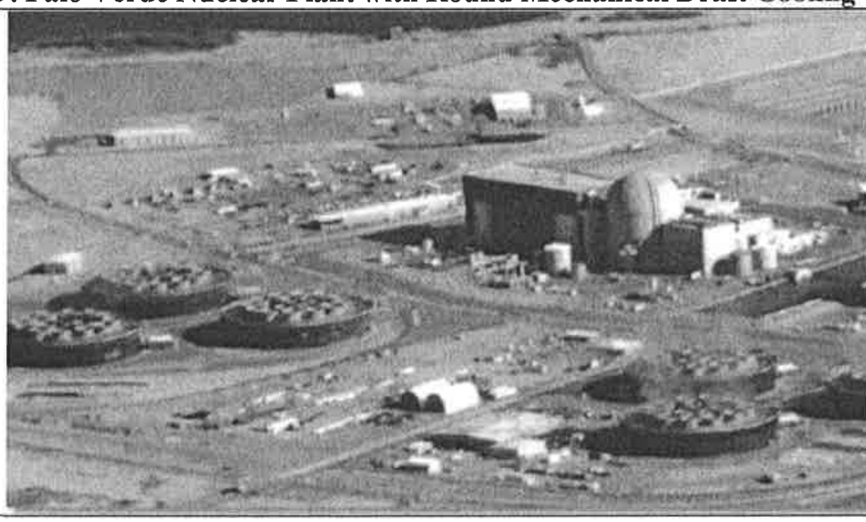
Palo Verde Nuclear Units 1-3: Palo Verde is the largest nuclear plant in the U.S. and is located about 40 miles west of Phoenix, Arizona. It began operation at about the same time as Diablo Canyon, in the mid-1980s.[51] Palo Verde employs round mechanical draft cooling towers in a closed cycle cooling system. Palo Verde utilizes treated wastewater from nearby Phoenix as water supply for the cooling towers. The total dissolved solids content, also known as "salt"

[47] Ibid, Appendix C - Site Visit and Telephone Interview Reports, p. APC-6.
[48] U.S. NRC webpage, Crystal River Nuclear Generating Plant, Unit 3, last updated February 20, 2014.
[49] Ibid.
[50] See **Attachment D**.
[51] J. Maulbetsch, M. DiFilippo, *Performance, Cost, and Environmental Effects of Saltwater Cooling Towers – PIER Final Consultant Report*, prepared for California Energy Commission, January 2010, Table 4-1, Salt Water Tower Installations, pp. 20-21. Palo Verde I, 1985; Palo Verde II, 1986; Palo Verde III, 1987.

content, in the cooling tower circulating water is about 70 percent that of seawater at 24,000 parts per million.[52]

The amount of salts released from the Palo Verde units is about the same as the release rate projected for DCPP. The drift salt content at Palo Verde, at 24,000 ppm, is about half the 52,000 ppm salinity projected for DCPP cooling towers. The circulating cooling water flowrates, 1,863,000 gpm at Palo Verde[53] and 1,736,600 gpm at DCPP, are about the same. The estimated drift rate at Palo Verde is 0.001 percent.[54] The SPX guarantee for the ClearSky™ towers is 0.0005 percent, one-half the estimated drift rate for the Palo Verde cooling towers. Therefore, the salt drift emission rate at Palo Verde is about the same as the salt drift emission rate projected for DCPP. Cooling tower salt deposition has been successfully managed at Palo Verde during nearly three decades of operation. Palo Verde Nuclear is shown in Figure 9.

Figure 9. Palo Verde Nuclear Plant with Round Mechanical Draft Cooling Towers[55]



Hope Creek Nuclear: The 1,172 MW Hope Creek nuclear plant, consisting of a single reactor snd is located on the Delaware Bay in southern New Jersey. This unit was designed and built by Bechtel. It began operation in 1986, at the same time that DCPP Units 1 and 2 became operational. The typical annual average salinity of the circulating water in the Hope Creek Nuclear cooling tower is in the range of 12,000 ppm. See calculation in **Attachment E**.

The average capacity factor of the Hope Creek Nuclear unit from 2008-2013 was 98 percent. The average capacity factor of DPCC Unit 1 during 2008-2013 was 92 percent. The average capacity factor of DPCC Unit 2 during 2008-2013 was 88 percent. Salt deposition from the use of high

[52] Ibid, p. 40. "The (Palo Verde) cooling towers are operated (on average) at 24 cycles of concentration—at times, as high as 30 cycles. Average feedwater TDS is approximately 1,000 mg/l. Therefore, circulating water TDS is approximately 24,000 mg/l, about 70 percent of normal seawater."

[53] Ibid, pp. 20-21.

[54] Diablo Canyon Independent Safety Committee, *Draft Evaluation of Safety Issues for "Addendum to the Independent Third Party Final Technologies Assessment for the Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for the Diablo Canyon Power Plant"*, October 7, 2014, p. 12.

[55] Ibid, p. 39.

salinity cooling water at Hope Creek Nuclear has not resulted in poorer reliability than achieved at DCPP using once-through seawater cooling. The capacity factors of Hope Creek Nuclear, DCPP Unit 1, and DCPP Unit 2 were all approximately 92 percent in the 2010-2013 period. See Tables 1 and 2 provided in **Attachment E**.

Figure 10. Hope Creek Cooling Tower[56]

The cooling tower at Hope Creek Nuclear is located in close proximity to the high voltage switchyard as shown in Figure 10. Despite this close proximity the capacity factors achieved at Hope Creek Nuclear, which has been in operation for 28 years, are as good or better than capacity factors being achieved by DCPP Units 1 and 2 using once-through seawater cooling. The conclusion that can be drawn from the actual long-term performance of the seawater cooling tower at Hope Creek Nuclear is that salt deposition from a seawater cooling tower at an operational nuclear plant is manageable and does not degrade plant reliability relative to a plant with an OTC cooling system.

EPRI modeling of salt deposition from inline mechanical draft cooling towers: Salt drift deposition models have been developed by the Electric Power Research Institute (EPRI) for inline mechanical draft cooling towers, such as the ClearSky™ cooling tower evaluated by Bechtel in the Final Addendum, and hyperbolic natural draft cooling towers.[57] The EPRI salt deposition model results for an example inline mechanical draft cooling tower indicates that more than 90 percent of the salt drift from the cooling tower deposits within 200 meters of the cooling tower, and that 95 percent or more of the salt drift deposits within 300 meters of the cooling tower.[58] See **Attachment F**.

The data used in this EPRI modeling exercise were taken from actual cooling tower drift measurements conducted on inline mechanical draft cooling towers at the (formerly PG&E) Pittsburg Generating Station in Pittsburg, California.[59] The Pittsburg plant consists of three steam generators, Units 5, 6, and 7. Units 5 and 6 are OTC units and generate a total of 660 MW (gross output).[60] Unit 7 is a closed-cycle wet cooled unit that generates 740 MW (gross output).[61]

---

[56] South Jersey Times, *PSEG Nuclear's Hope Creek reactor shut down for scheduled refueling outage*, October 12, 2013.
[57] Most EPRI members are electric utilities. See EPRI "Our Members" webpage, as of October 26, 2014: http://www.epri.com/About-Us/Pages/Our-Members.aspx.
[58] Engineering and Environmental Science, *USER'S MANUAL: COOLING-TOWER-PLUME PREDICTION CODE (Revision 1) - A computerized methodology for predicting seasonal/annual impacts of visible plumes, drift, fogging, icing, and shadowing from single and multiple sources*, prepared for Electric Power Research Institute, September 1987, Table 3-17, p. 3-32. See **Attachment F**.
[59] Ibid. p. 3-2.
[60] GenOn Detla, LLP, *Pittsburg Generating Station Implementing Plan for the Statewide Water Quality Control Policy on Use of Coastal and Estuarine Waters for Power Plant Cooling*, April 1, 2011, p. 1.

Pittsburg Unit 7 was retrofit from OTC to non-plume abated inline mechanical draft cooling towers in 1976 at a cost $34.4 million (adjusted to 1999 dollars).[62] The cooling tower consists of two 13-cell inline cooling towers with a total circulating cooling water flowrate of 352,000 gpm.[63]

The tested drift eliminator efficiency of the Pittsburg Unit 7 cooling towers was 0.0006 percent.[64] This is similar to the drift eliminator efficiency of 0.0005 percent assumed by Bechtel for the ClearSky™ seawater cooling towers on DCPP Units 1 and 2.[65] Therefore, the salt deposition modeling results developed by the EPRI contractor based on Pittsburg Unit 7 drift measurements can be considered reasonably representative of the salt deposition footprint that will be generated by the proposed seawater cooling towers at DCPP.

Bechtel has located the leading edge of the Unit 1 34-cell cooling tower at least 600 meters from the trailing edge of the DCPP turbine building. The center of the Unit 1 cooling tower is more than 700 meters from the trailing edge of the turbine building. The Unit 2 34-cell cooling tower leading edge is at least 300 meters from the trailing edge of the turbine building. The center of the Unit 2 cooling tower is more than 400 meters from the trailing edge of the turbine building.[66]

The cooling tower circulating water flowrate modeled by ERPI is not the same as the flowrate proposed for the seawater cooling towers at DCPP. Powers Engineering recommends the seawater cooling towers at DCPP operate with an optimized circulating water flowrate of 600,000 gpm. Bechtel assumes the cooling towers will operate with the same circulating water flowrate as the current OTC system, 868,300 gpm. Either of these flowrates is a larger than the 352,000 gpm flowrate modeled in the EPRI case study. However, the qualitative result of the EPRI drift modeling exercise is that much of the salt drift will deposit close to the cooling tower.

Almost no salt drift from the Unit 1 seawater cooling tower should reach the DCPP turbine building and immediate surroundings, regardless of the wind direction, based on a qualitative extrapolation of the EPRI salt drift modeling results (by Powers Engineering) to the larger circulating cooling water flowrates proposed for the DCPP seawater cooling towers.

Only a small amount of salt drift from the Unit 1 seawater cooling tower, on the order of 10 percent or less, should attain sufficient distance from the Unit 1 cooling tower to physically reach the turbine building and immediate surroundings. Given the prevailing wind at DCPP is predominantly from the turbine building toward the proposed Unit 1 and 2 cooling towers, only a small fraction of the time would the wind direction be favorable toward any Unit 2 cooling tower salt drift depositing on or near the turbine building.

---

[61] Ibid.
[62] U.S. EPA, *Technical Development Document (TDD) for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002. Chapter 4, *Cooling System Conversions at Existing Facilities*, p. 4-5 and p. 4-6.
[63] Ibid, p. 4-5.
[64] L.S. Laulainen – Pacific Northwest Laboratory, *Drift Deposition from Mechanical Draft Cooling Towers*, p. 3. "The result was found to be 4.8 g/s per cell or 124 g/s total emission rate if all 26 cells (Pittsburg Unit 7) are operating. This corresponds to a drift fraction of 0.0006% for a total circulating water flow rate of 20 m^3/s."
[65] Final Addendum, September 17, 2014, p. 15.
[66] See **Attachment A, Figures A-1 and A-2** to view the distance between the Unit 1 and 2 cooling towers and the DCPP turbine building.

11. Conclusions

The 34-cell ClearSky™ back-to-back plume-abated mechanical draft cooling tower evaluated by Bechtel is the appropriate cooling tower alternative for seawater cooling tower retrofits at DCPP. Powers Engineering estimates the overall cost of seawater cooling tower retrofit at Diablo Canyon Power Plant (DCPP) at approximately $1.2 billion. This estimated cost includes all costs related to the construction of the cooling towers ($500 million), the cost of replacement power during the outage necessary to tie-in the cooling towers to the existing DCPP circulating water ducts ($400 million), and a 30 percent contingency for a study-level cost estimate ($300 million).

The Bechtel cost estimate includes inflated and unnecessary costs. There is no technical necessity to drop the elevation of the cooling tower south parking area sites to 115 feet above sea level as proposed by Bechtel. Eliminating this unnecessary work reduces DCPP cooling tower construction costs in the Bechtel estimate from $1.4 billion to about $400 million.

The forced construction outage of 2.3 years estimated by Bechtel for the cooling tower retrofit, with an associated replacement power cost of $1.9 billion, compares to the U.S. EPA estimate of the forced outage duration of a nuclear plant cooling tower retrofit from zero to 24 weeks. The replacement power cost for the worst-case EPA outage scenario, 24 weeks, would be about $400 million.

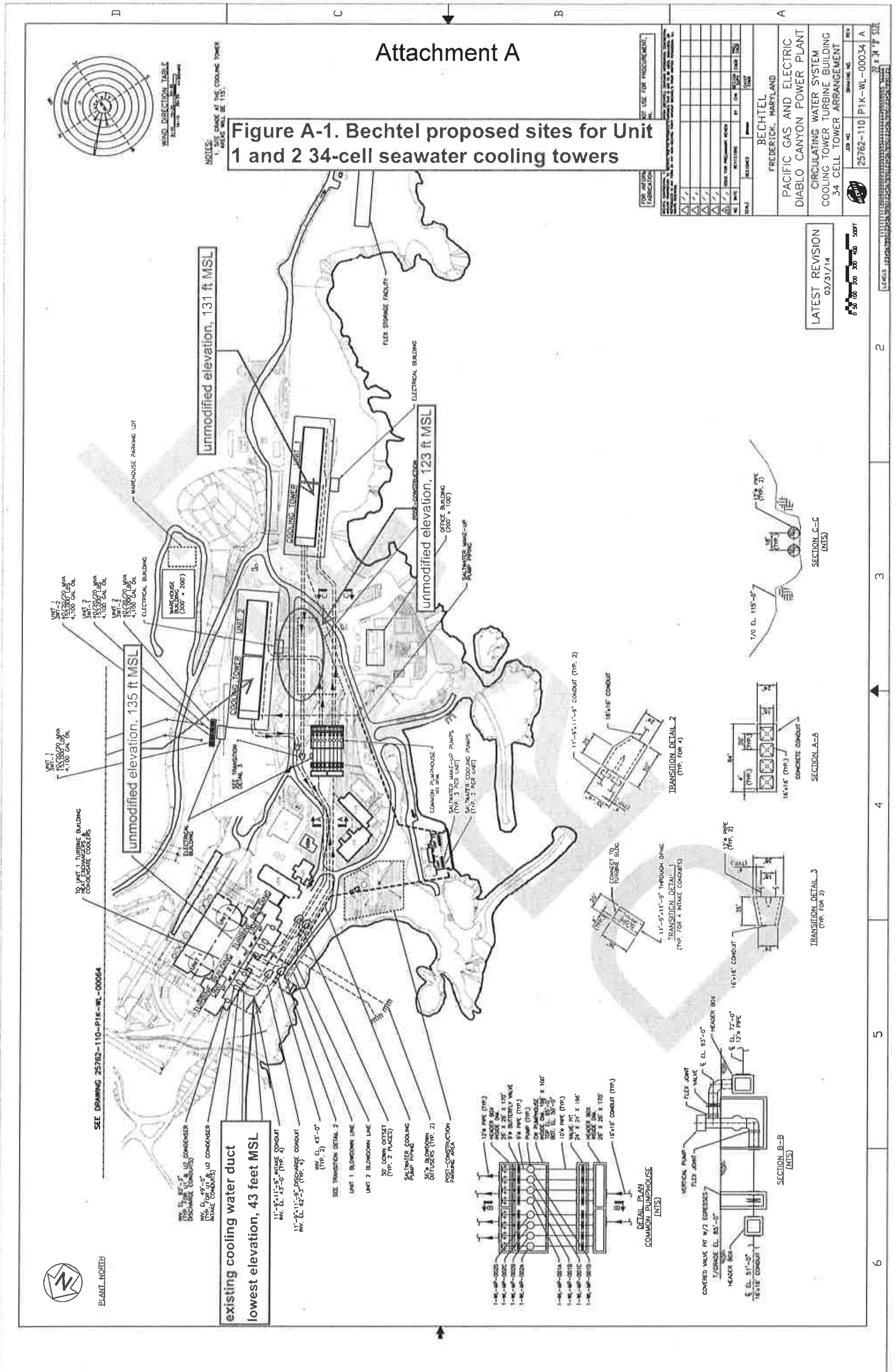
Bechtel's projected cost for the DCPP cooling tower conversion is $6.2 billion to $7.9 billion. This project cost is excessive. It is ten times or more the $660 million cost of the cooling tower retrofit at 1,500 MW Brayton Point Station completed in 2012. Powers Engineering concurs with the September 12, 2014 recommendations of the Subcommittee of the Review Committee for Nuclear Fueled Power Plants that the appropriate course of action is to move beyond the Bechtel cost estimate and put the DCPP cooling tower retrofit project out to competitive bid.

An optimized 34-cell cooling tower would impose a total efficiency penalty of about 6 percent compared to the existing once-through cooling (OTC) system on Units 1 and 2. This efficiency penalty should be partially offset by improved plant reliability. The conversion to closed-cycle cooling will eliminate two major reliability issues associated with the existing OTC system: 1) intake structure blockage by kelp and marine life, and 2) transformer arcing incidents caused in part by salt spray from the OTC outfall in front of the turbine building depositing on transformers downwind of the outfall and behind the turbine building.

Salt deposition at power plants using seawater cooling towers has proven to be manageable and has not led to reduce reliability. The seawater cooling towers at DCPP would be downwind of the turbine building and reactors in the prevailing wind direction, which would minimize salt deposition impacts.

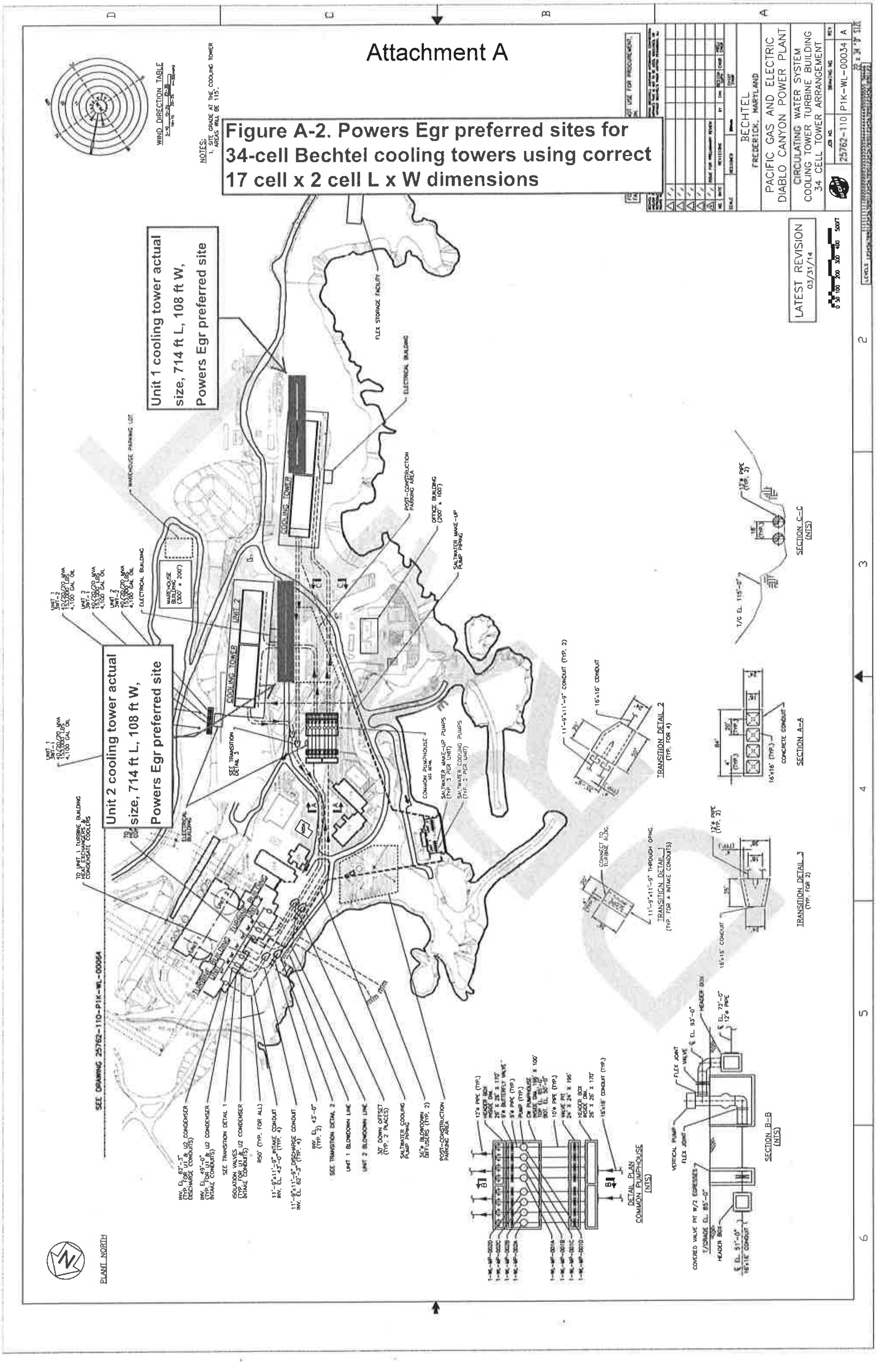
Attachment A

Figure A-1. Bechtel proposed sites for Unit 1 and 2 34-cell seawater cooling towers



Attachment A

Figure A-2. Powers Egr preferred sites for 34-cell Bechtel cooling towers using correct 17 cell x 2 cell L x W dimensions



Attachment A

Figure A-3. Bechtel simulation of 34-cell seawater cooling towers for DCPP Units 1 and 2 (Sept. 17, 2014 Final Addendum)

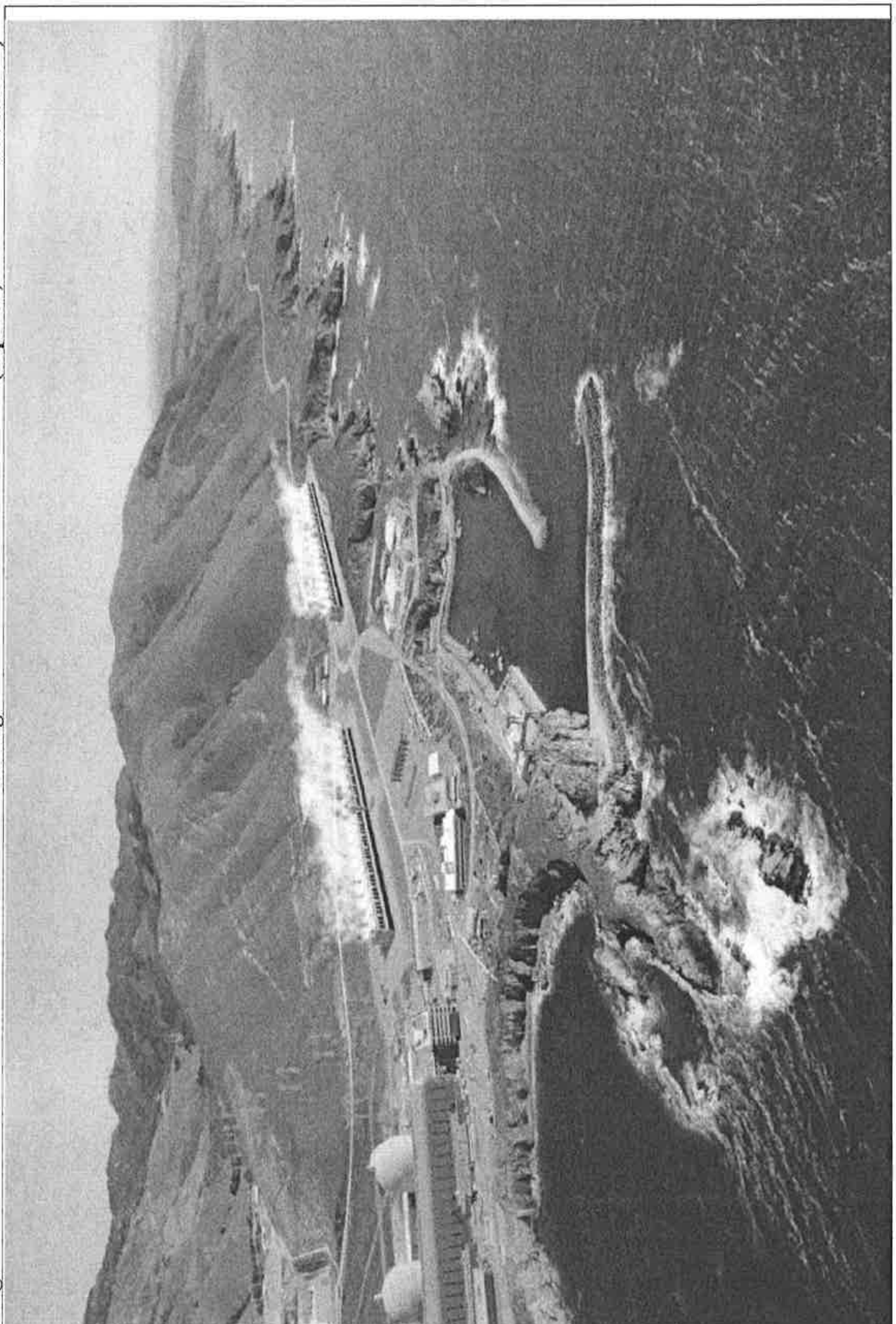


Table E-1. Powers Engineering ClearSky™ alternative performance at design conditions: 34 cells, 54 ft wide by 48 ft long each, 600,000 gpm, 23.5 °F approach T @ 64.5 °F

ClearSky™ back-to-back cooling tower design	# cells[1]	Cooling cell & tower dimensions (W x L, feet)	Cooling cell fill depth, feet	Cooling water flowrate, gpm[1]	Design heat removal, MMBtu/hr	Plume point, DB/RH	Approach T at 64.5 °F WB[2]	Increase in temperature across condenser (range) , °F	TTD, °F[3]	Steam condensation temperature, °F	Estimated steam turbine backpressure at 64.5 °F WB, inch Hg
Adjusted SPX 2009 generic ClearSky™ nuclear plant specification	34 (2x17)	cell: 54 x 48 tower: 108'x816' (Model F498)	Not specified in quote	600,000	7,599	50 °F, 90%	23.5	25	~11	124	3.86 (1.90 psi)

[1] SPX Cooling Tower Performance – Basic Theory and Practice, June 1986, Figure 5, p. 3. Cooling water flow reduction from 830,000 gpm to 600,000 gpm reduces tower size by about 18 percent (from 1.0 tower size factor to 0.82 tower size factor). This flow reduction would reduce the number of seawater cooling tower cells in the original SPX ClearSky design (included in Attachment E) to maintain a 12 °F approach temperature at 76 °F WB from 66 cells to 54 cells. Ibid, Figure 6, p. 4. A 7 °F increase in approach temperature in the original SPX 830,000 gpm design, 12 °F approach at design WB of 76 °F, increases the approach temperature from 12 °F to 19 °F and reduces cooling tower size by approximately 36 percent, from 54 cells to 34 cells.

[2] A 19 °F approach temperature at 76 °F WB is equivalent to an approach temperature of approximately 23.5 °F for the same cooling tower at a WB of 64.5 °F.

[3] Tetratech 2008 (Table C-5, p. C-10) indicates the DCPP Unit 1&2 surface condensers have a Terminal Temperature Difference (TTD) of 13.7 °F, with a design flowrate of 862,690 gpm and surface area of 617,536 ft^2. Bechtel provided data (handout, April 8, 2014) indicating the Vogtle 3&4 nuclear units (under construction) have a design cooling tower flowrate of 624,800 gpm and a condenser surface area of 1,246,425 ft^2, about double the surface area of the DCPP Unit 1&2 surface condensers. The TTD of the Vogtle 3&4 surface condensers is 5.3 °F at design conditions (J. Cuchens, Southern Company Generation, Feasibility of ACC for AP1000 Reactor, June 25, 2007, p. 7). Powers Engineering professional judgment is that the TTD of the DCPP Unit 1&2 surface condensers will drop from 13.7 °F at 862,690 gpm to 11 °F or less at the substantially reduced flowrate of 600,000 gpm, due to the greater residence time of the cooling water in the surface condenser, in an optimized 34-cell ClearSky™ cooling tower.

Attachment B

Table E-2. Monthly average backpressure change, OTC versus Powers Engineering ClearSky™ tower design

Month	Average wet bulb (°F)	Approach T (oF)	Range (oF)	TTD (oF)	Steam condensation temperature (oF)	Back-pressure, inches Hg	Change in heat rate from design condition, cooling tower (%)	Change in heat rate from design condition, OTC (%)	Net change in heat rate OTC to cooling tower, (%)
January	46.0	35	26.5	11	118.5	3.33	+6.3	+0.8	+5.5
February	47.4	34.0	26.5	11	118.5	3.33	+6.5	+0.7	+5.8
March	48.8	33.0	26.5	11	119.5	3.41	+6.5	+0.6	+5.9
April	49.6	33.0	26.5	11	120	3.44	+6.3	+0.5	+5.8
May	52.9	30.5	26.5	11	121	3.55	+6.7	+0.5	+6.2
June	55.2	29.5	26.5	11	122	3.65	+6.7	+0.7	+6.0
July	57.5	27.5	26.5	11	122.5	3.69	+6.7	+0.8	+5.9
August	57.9	27.5	26.5	11	123	3.69	+6.8	+0.8	+6.0
September	57.1	28.0	26.5	11	122.5	3.69	+6.7	+1.0	+5.7
October	53.3	30.5	26.5	11	121	3.55	+6.7	+1.0	+5.7
November	49.8	32.5	26.5	11	120	3.44	+6.7	+1.0	+5.7
December	45.8	35.0	26.5	11	118.5	3.33	+6.5	+0.9	+5.6

Average annual net change = +5.8%

DCPP Units 1 and 2 OTC output is ~1,100 MW per unit.

Therefore, +5.8 percent heat rate increase = 1,100 MW x 0.058 = 64 MW loss per unit annual average.

This is a gross loss of output without adjustment for downtime caused by existing OTC-related reliability issues such as intake structure clogging and OTC outfall salt spray effects on Unit 2 transformers.

Change in heat rate data from: TetraTech 2008, Diablo Canyon Power Plant, p. C-22 (attached).

Average monthly wet bulb temperature San Luis Obispo, 1998-2011, from: National Climate Data Center (attached).

Powers Engineering

systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

Table C–12 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to develop an estimate of the monetized value of these heat rate changes (Section 4.6.2). Month-by-month calculations are presented in Appendix A.

Table C–12. Summary of Estimated Heat Rate Increases

	Unit 1	Unit 2
Peak (July-August-September)	3.60%	3.60%
Annual average	3.61%	3.61%

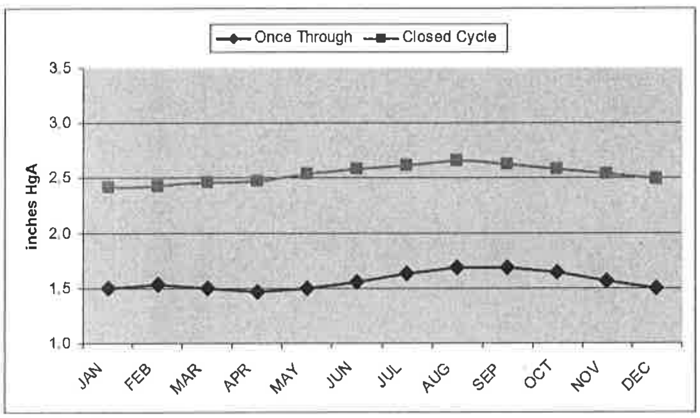


Figure C–9. Estimated Backpressures (Unit 1)

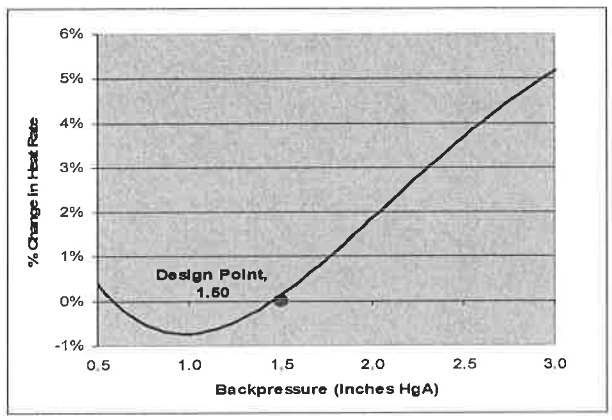


Figure C–10. Estimated Heat Rate Correction (Unit 1)

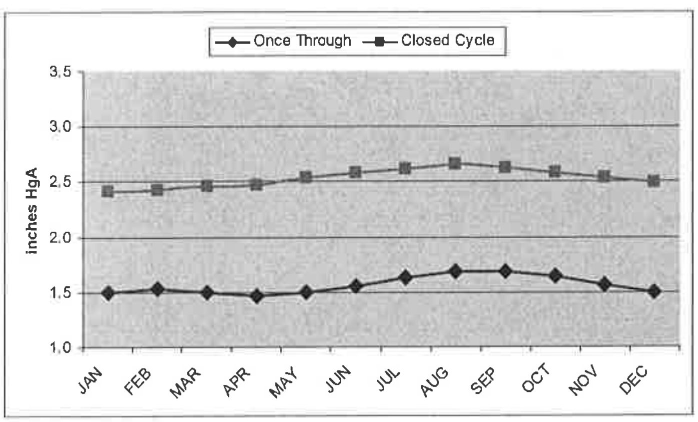


Figure C–11. Estimated Backpressures (Unit 2)

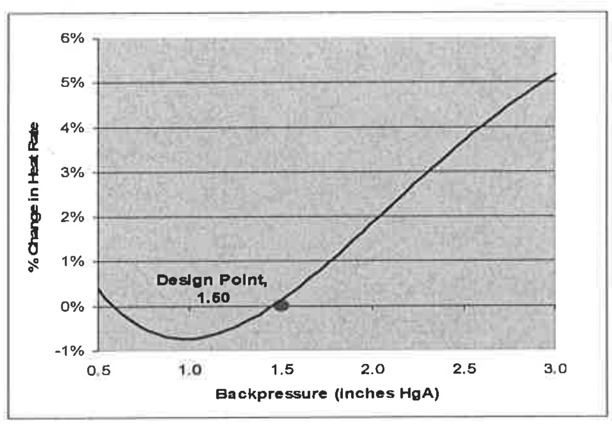


Figure C–12. Estimated Heat Rate Correction (Unit 2)

Attachment B

San Luis Obispo, California: Average Monthly Wet Bulb Temperature

Source: National Climate Data Center, http://www.wrcc.dri.edu/htmlfiles/westcomp.wb.html

Years	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1998-2011	46.0	47.4	48.8	49.6	52.9	55.2	57.5	57.9	57.1	53.3	49.8	45.8	51.8

Attachment B

Nuclear Plant Retrofit Comparison for Powers Engineering 9-June-2009

	Case 1A	Case 2A	Case 1B	Case 2B
Water	Salt	Salt	Fresh	Fresh
Type	ClearSky BTB	Wet BTB	ClearSky BTB	Wet BTB
Cells	3x22=66	3x18=54	3x20=60	3x18=54
Footprint	3@529x109	3@433x109	3@481x109	3@433x109
Rough Budget	$115.6 million	$38.6	$109.1	$36.4

Basis: 830,000 gpm at 108-88-76. Plume point is assumed at 50 DB/90% RH.

Low clog film type fill is used for all of the selections, assuming any fresh water used would likely be reclaimed water of some sort. Low clog fill has been used successfully in various sea water applications. Intake screens would be required for the make-up sea water to limit shells, etc. Make-up for the ClearSky tower would be approximately 80-85% of the wet tower make-up on an annual basis. Budget is tower only, not including basins. Infrastructure cost is estimated by some at 3 times the cost of the wet tower, including such things as site prep, basins, piping, electrical wiring and controls, etc. Sub-surface foundations such as piling can add significantly, and may be necessary for a seacoast location. The estimates above are adjusted for premium hardware and California seismic requirements, which are a factor in the taller back-to-back (BTB) designs both for wet and ClearSky. These are approximate comparisons. Both the wet towers and ClearSky towers could likely be optimized more than what has been estimated here, and may have to be tailored to actual site space in any event. ClearSky has pump head like a wet tower, is piped like a wet tower, and has higher fan power than a wet tower to accommodate the increased air flow and pressure drop.

Coil type wet dry towers would cost significantly more, with premium tube (titanium for sea water, and possibly for reclaimed water) and header materials. An appropriate plenum mixing design has yet to be developed, but would also require non-corrosive materials and high pressure drop on the air side. No coil type BTB wet dry towers are likely to be proposed.

Attachment B

Bill Powers

From: PAUL.LINDAHL@ct.spx.com
Sent: Tuesday, June 09, 2009 9:27 AM
To: bpowers@powersengineering.com
Subject: Nuclear Comparison

Bill,

A comparison of wet and ClearSky back to back towers for a reference duty is included in the attached summary.

SPX

Paul Lindahl, LEED AP
Director, Market Development
SPX Thermal Equipment & Services
7401 W 129th St
Overland Park, KS 66213
TEL 913.664.7588
MOB 913.522.4254
paul.lindahl@spx.com
www.spxcooling.com
www.balcke-duerr.com/

Attachment B

Bill Powers

From: LINDAHL, PAUL <PAUL.LINDAHL@spx.com>
Sent: Tuesday, June 14, 2011 8:28 AM
To: Bill Powers
Subject: RE: pump head above basin curb - ClearSky plume-abated cooling tower

Same as a wet-only tower. No water goes above the spray system. A large back-to-back tower might be about 35 ft. of H2O pump head. Varies with the air inlet height, fill height, and dynamic head in the piping.

Best regards,

SPX

Paul Lindahl, LEED AP
Director, Market Development
SPX Thermal Equipment & Services

7401 W 129 Street
Overland Park, KS 66213
TEL +1 913-664-7588
MOB +1 913-522-4254
FAX +1 913-693-9310
paul.lindahl@spx.com
www.spx.com

From: Bill Powers [mailto:bpowers@powersengineering.com]
Sent: Monday, June 13, 2011 8:42 PM
To: LINDAHL, PAUL
Subject: pump head above basin curb - ClearSky plume-abated cooling tower

Hello Paul,

What is the approximate pump head above the basin curb for the ClearSky plume-abated cooling tower?

Thanks,

Bill Powers

Attachment C

PAPER NO: **TP03-17**

CATEGORY: **MECHANICAL DRAFT TOWERS**

COOLING TECHNOLOGY INSTITUTE

FEASIBILITY OF SEAWATER COOLING TOWERS FOR LARGE-SCALE PETROCHEMICAL DEVELOPMENT

DR. SHAHRIAR EFTEKHARZADEH
DR. MUIN M. BAASIRI
BECHTEL CORPORATION

PAUL LINDAHL, JR.
MARLEY COOLING TECHNOLOGIES

Presented at the 2003 Cooling Technology Institute Annual Conference
San Antonio, Texas – February 10-13, 2003

Attachment C

Table 7: Installation List of Seawater Cooling Towers (10)

Year	Client	Project	Country	Flow (m^3/hr)
1973	I. S. A. B.	SIRACUSA	IT	16,000
1973	ATLANTIC CITY ELECTRIC CO (NJ)	BEESLEY'S POINT	US	14,423
1976	PUBLIC SERV. ELEC. & GAS CO	HOPE CREEK	US	250,760
1978	E. B. E. S. - DOEL NUCLEAR PP	DOEL	BE	183,240
1979	JEDDAH INT. AIRPORT	JEDDAH	SA	35,400
1981	JACKSONVILLE ELEC. AUTH.	JACKSONVILLE (FL)	US	112,520
1984	GUJARAT ELECTRICITY BOARD	PANANDRA KUTCH - GUJARAT	IN	33,100
1985	SIAPE	SFAX	TN	8,000
1990	FLORIDA POWER CORP.	ST PETERSBURG	US	156,000
1990	C. E. G. B.	KILLINGHOLME	GB	46,872
1991	BASF	ANVERS	BE	14,500
1992	ATLANTIC CITY ELECTRIC CO	B. L. ENGLAND, N. J.	US	16,280
1993	POWERGEN	CONNAH'S QUAY	GB	85,392
1993	E. G. A. T.	BANG PAKONG	TH	71,100
1995	E.G.A.T.	SOUTH BANGKOK	TH	33,500
1996	AMATA EGCO B	BANG PAKONG	TH	12,168
1996	MEDWAY POWER Ltd	MEDWAY	GB	35,380
1997	GEM METHANOL TRINIDAD	TRINIDAD		12,513
1997	ECOELECTRICA, LP	PENUELAS		2,184
1997	ECOELECTRICA, LP	PENUELAS		35,408
1998	EGAT	KRABI	TH	48,100
1999	KALTIM PARNA INDUSTRY	BONTANG	ID	17,000
1999	ESSO SINGAPORE PVT LTD	SINGAPORE	SG	4,088
1999	FLORIDA POWER COPR CRYSTAL RIVER PLANT	CRYSTAL RIVER FLORIDA	US	67,229
2000	ESSO SINGAPORE PTE LTD	SINGAPORE	SG	14,082
2000	ENDESA	SAN ROQUE	ES	16,142
2000	ST JOHNS RIVER POWER PARK	JACKSONVILLE FL.	US	56,258
2001	GB3	LUMUT	MY	34,050
2001	ENDESA	TARRAGONA	ES	28,272
2001	PETROBRAS	TERMORIO	BR	55,000
2002	JUBAIL UNITED PETROCHEMICAL	JUBAIL	SA	66,605

Costs

The true cost of a cooling system to the industry is determined by accounting for both the initial and the running costs over the economic life of the system (life-cycle cost). The initial costs are comprised of equipment purchase, transport, customs clearance, taxes, land acquisition, power acquisition, civil, mechanical, electrical, piping works, and testing and commissioning. The operation and maintenance costs include makeup & blowdown charges, electricity, water treatment, O&M crew, parts, and materials.

For this study, a typical 70,000 m^3/hr system with a duty of 45 °C HWT, 35°C CWT, and 32 °C WBT was selected for life-cycle cost analysis. Such a tower would

Attachment D

Comparison of 10-year average capacity factores for Crystal River Nuclear Unit 3 and DCPP Units 1 and 2

(permitted salt drift from seawater cooling towers at Crystal River is 1,692 tpy)

Unit	10-yr average CF prior to steam generator replacement outage	10-yr average capacity factor
Crystal River Unit 3	1999-2008	93.2
DCPP Unit 1	1999-2008	90.0
DCPP Unit 2	1998-2007	91.2

Crystal River Unit 3, capacity factor		DCPP Unit 1, capacity factor		DCPP Unit 2, capacity factor	
1999	88.9	1999	87.5	1998	85.7
2000	97.2	2000	83.3	1999	88.7
2001	89.2	2001	100	2000	96.2
2002	99.9	2002	74	2001	90.9
2003	90.1	2003	100.7	2002	97.5
2004	99.2	2004	75.8	2003	81.1
2005	86.5	2005	87.4	2004	84.0
2006	94.7	2006	101.2	2005	99.1
2007	90.9	2007	90.2	2006	89.6
2008	95.1	2008	100.3	2007	99.2
ave.	93.2	ave.	90.0	ave.	91.2

Permitted salt drift emission rate of onsite Crystal River seawater cooling towers = helper cooling towers + Unit 4&5 cooling towers

Annual salt drift emision air permit limit = 925 tpy + 767 tpy = 1,692 tpy

See attached: 1) 2010 Crystal River Title V air permit for cooling tower salt drift limits and 2) 1995 FPL letter with seawater cooling tower parameters salt deposition isopleth map showing location of seawater cooling towers and Nuclear Unit 3.

Source of capacity factor data: International Atomic Energy Authority

Crystal River Unit 3: http://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=645

DCPP Unit 1: http://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=628

DCPP Unit 2: http://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=660

Attachment D

Florida Power Corporation
dba Progress Energy Florida, Inc. (PEF)
Crystal River Power Plant

Facility ID No. 0170004
Citrus County

Title V Air Operation Permit Renewal

Permit No. 0170004-024-AV
(Renewal of Title V Air Operation Permit No. 0170004-009-AV)

Permitting Authority:

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Title V Section

2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: (850) 488-0114
Fax: (850) 921-9533

Compliance Authority:

State of Florida
Department of Environmental Protection
Southwest District Office

13051 North Telecom Parkway
Temple Terrace, FL 33637-0926

Telephone: 813/632-7600
Fax: 813/632-7668

Title V Air Operation Permit Renewal

Permit No. 0170004-024-AV

Table of Contents

Section **Page Number**

Attachment D

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

PERMITTEE:
Florida Power Corporation
dba Progress Energy Florida, Inc.
299 First Avenue North
Mail Code CN77
St. Petersburg, Florida 33701

Permit No. 0170004-024-AV
Crystal River Power Plant
Facility ID No. 0170004
Title V Air Operation Permit Renewal

The purpose of this permit is to renew the Title V air operation permit for the above referenced facility. The existing Crystal River Power Plant is located in Citrus County at 15760 West Power Line Street, Crystal River, Florida. UTM Coordinates are: Zone 17, 334.3 km East and 3204.5 km North. Latitude is: 28° 57' 34" North and Longitude is: 82° 42' 1" West.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

Effective Date: January 1, 2010
Renewal Application Due Date: May 20, 2014
Expiration Date: December 31, 2014

Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/jkh/sm

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
013	Cooling Towers for FFSG Units 1, 2 and Nuclear Unit 3

Emissions unit 013 (EU013) is cooling towers for FFSG units 1, 2 and nuclear unit 3, used to reduce plant discharge water temperature. (This emissions unit may be referred to as "helper cooling towers.") This emissions unit consists of four towers with nine cells per tower, with high efficiency (99.8%) drift eliminators, operating at a maximum seawater flow rate of 735,000 gallons per minute for all nine cells combined, with a design airflow rate of 1.46 x 10^6 acfm from each cell. Seawater is sprayed through the towers where fan induced air flow causes evaporative cooling. Water vapor, saltwater droplets (drift) and salt particles are emitted. Drift emissions are controlled by high efficiency drift eliminators.

{Permitting note(s): This emissions unit is regulated under Prevention of Significant Deterioration (PSD) (PSD permit AC09-162037/PSD-FL-139 issued 8/29/90) and Best Available Control Technology (BACT), Determination dated 8/29/90, which set a drift emission rate of 0.004%.}

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. The operating hours for each cooling tower pump shall not exceed 4,320 hours per year (12-month rolling total). [Rule 62-210.200(PTE), F.A.C.; and, Permit No. AC09-162037/PSD-FL-139]

F.2. Drift Eliminators. Drift eliminators shall be installed and maintained so that minimum bypass occurs. Regular maintenance shall be scheduled to ensure proper operation of the drift eliminators. [Rule 62-213.440, F.A.C.; and, Permit No. AC09-162037/PSD-FL-139)]

{Permitting Note: This emissions unit is not subject to a visible emissions limitation. Emissions from this emissions unit include water droplets so visible emissions testing is not possible.}

F.3. Pump Run Time Meters Required. Each cooling tower seawater pump shall be equipped each with a run-hour meters. [Rule 62-213.440, F.A.C.; and, AC09-162037/PSD-FL-139]

F.4. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Conditions **F.5.** is based on the specified averaging time of the applicable test method.

F.5. Cooling Tower Emission Limit. The maximum allowable emissions of particulate matter form each cell (stack) is 11.89 lb/hr. This is based on a 0.004% drift rate (ratio of drift to the circulate rate) and the following table:

Flow Rate (gpm)	Total PM (from all 36 cells)		PM_{10}	
	lbs/hr	TPY	lbs/hr	TPY
735,000	428	925	214	462

(PM_{10} is approximately 50% of total PM)

[Permit No. AC09-162037/PSD-FL-139, BACT]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

F.6. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

F.7. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures

F.8. Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

F.9. Emission Test Method. The drift elimination system on the helper cooling towers shall be maintained so as to minimize pluggage and to insure timely repair of broken sections of the drift eliminators. During the warm months when the helper cooling towers are used, the following work practice shall be implemented, in lieu of EPA Method 5, to demonstrate compliance with the originally designed removal efficiency (no more than 0.004% drift rate):

a. Daily "walk down" inspection of each operational cell visually checking for problems with the drift eliminators such as pluggage, algae build-up, and mechanical components (fans and pumps).
b. Daily visual inspection of the cells which are in operation to ascertain the presence of higher than expected visible emissions when atmospheric conditions allow, and follow-up inspections and correction of problems when the daily visual inspection of the cells indicates a problem.
c. Weekly visual inspection of the inlet water screens and prompt correction when broken sections or pluggage is discovered.

[Rule 62-213.440, F.A.C.; and, AC 09-162037 (PSD-FL-139); and, ASP No. 00-E-01 dated June 7, 2000]

Recordkeeping and Reporting Requirements

F.10. Pump Run Logs. A log shall be maintained of the hours of operation of each pump supplying salt water to the helper cooling towers. Pump flow rates shall be determined from the manufacturer's certified pump curves, or any other equivalent method approved by the Department. [Rule 62-213.440, F.A.C.; Permit No. AC09-162037/PSD-FL-139]

F.11. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
015	Cooling Towers for FFSG Units 4 and 5

Emissions unit 015 (EU015) is cooling towers for FFSG Units 4 and 5 used to reduce plant discharge water temperature. (These towers are hyperbolic cooling towers.) Seawater is sprayed through the towers where induced air flow causes evaporative cooling. Water vapor, saltwater droplets (drift) and salt particles are emitted. Drift emissions controlled by high efficiency drift eliminators. Seawater flow rate is 331,000 gallons per minute.

{Permitting note(s): This emissions unit is regulated under Prevention of Significant Deterioration (PSD) (PSD permit PSD-FL-007 issued by EPA as modified by EPA on 11/30/88.)}

Essential Potential to Emit (PTE) Parameters

G.1. Permitted Capacity. The maximum seawater flow rate shall not exceed 331,000 gallons per minute per cooling tower. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C., 62-204.800, F.A.C.]

G.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

G.3. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Condition(s) **G.4.** is based on the specified averaging time of the applicable test method.

G.4. PM Emissions - Cooling Tower Emission Limit. PM emissions shall not exceed 175 lb/hr from each cooling tower. [Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

{Permitting Note: The emission limit is based on a BACT Determination requiring control of drift emissions with drift eliminators. The modified PSD permit removed a limitation on drift rate, substituting an emissions limit in pounds per hour. PM emissions are assumed to be all PM_{10}.}

{Permitting Note: This emissions unit is not subject to a visible emissions limitation. Emissions from this emissions unit include water droplets so visible emissions testing is not possible.}

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

G.5. Excess Emissions. Should either tower emission rate exceed 175 lb/hr, the permittee shall:

a. Notify EPA and the Department within 10 days of becoming aware of the exceedance.
b. Provide an assessment of necessary corrective actions and a proposed schedule of implementation within an additional 20 days.
c. Expeditiously complete corrective actions.
d. Retest the tower within three months after the correction is completed.
e. Submit the testing report within 45 days after completion of said tests.

[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

G.6. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

G.7. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

G.8. Inspection. The drift eliminators of both towers shall be inspected from the concrete walkways not less than every three months by Progress Energy Florida staff or representatives to assure that the drift eliminators are clean and in good working order. Not less than annually, a complete inspection of the towers shall be conducted by a qualified inspector with recognized expertise in the field. Certification that the drift eliminators are properly installed and in good working order shall be provided in the record keeping and reporting requirements noted below. [Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88].

Test Methods and Procedures

G.9. Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

G.10. Test Every Five Years. The FFSG Unit 4 cooling tower shall be tested every five years from 1988 (the next required year from the effective date of this permit is 2013). The FFSG Unit 5 cooling tower shall be tested every five years from 1992 (the next required year from the effective date of this permit is 2012). [Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

G.11. PM Emission Test Method. Testing shall be in accordance with following requirements:

a. PM emissions shall be measured by the sensitive paper method.
b. Testing shall be conducted either at the drift eliminator level within the tower or at the tower exit plane. (The sampling locations at the drift eliminator level and apparatus are shown in diagrams attached as Appendix P.)
c. No less than three test runs shall be conducted for each test and all valid data from each of these test runs shall be averaged to demonstrate compliance. No individual test run result shall determine compliance or noncompliance. The emission rate reported as a percent of the circulating water, as well as lb/hr., and total dissolved solids in the cooling tower basin and intake water, shall be reported for each test run.

[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

Recordkeeping and Reporting Requirements

G.12. Reporting. Reports on tower testing and inspection shall be handled as follows:

a. Maintained within onsite files within 30 days after all visual inspections of the drift eliminators.
b. Agency Submittal within 45 days after the compliance testing of either tower.

[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

G.13. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

Attachment D

Florida Power
CORPORATION

bcc: David Voigts
Mike Kennedy

File: Crystal River Salt Drift Study

May 24, 1995

saltend2\524

Mr. Hamilton S. Oven, Jr.
Florida Department of Environmental Protection
Douglas Building, Room 953AA
2900 Commonwealth Blvd., MS 48
Tallahassee, FL 32399-3000

Dear Mr. Oven:

Re: Crystal River Salt Drift Study
Permit Number PSD-FL-007

Enclosed is the Annual Report of the Crystal River Salt Drift Study 1993-1994 study year, the 13th year of the study. As noted in the conclusions, the vegetation generally continued to be in good condition. Accordingly, Florida Power again formally requests that DEP approve the discontinuation of the Crystal River salt drift study.

Florida Power Corporation (FPC) has been conducting this salt drift deposition study since 1981 to assess the effects of the two natural draft cooling towers which serve Units 4 and 5 at FPC's Crystal River plant. In addition, the study has, for the past two years, been used to determine whether any vegetation damage is occurring due to salt deposition from the new mechanical helper cooling towers for Units 1, 2, and 3.

The study, originally a part of the NPDES permit and the Site Certification for Units 4 and 5, was incorporated into the PSD permit referenced above on November 30, 1988. Condition 5.c. contains language regarding changes to the monitoring program, which includes the following:

> *Should the data indicate that no significant impacts are occurring to the surrounding area, the permittee, after consultation with and approval by the Director of the EPA Region IV Air, Pesticides, and Toxics Management Division and FDER, may reduce or eliminate the monitoring program.*

In past correspondence and at a November 2, 1994, meeting in Crystal River, FPC has presented its rationale for stopping the study. However, since FPC has not been allowed to end the study, and in response to questions that have been asked, FPC offers the following information that gives additional reasons and documentation to support the request to end the salt drift study. Discussed are a June 1988 deposition modeling study for the Crystal River cooling towers by KBN Engineering, the results and subsequent ending of a three-year salt drift study for the St. Johns River Power Park, and the questionable scientific validity of such studies.

KBN Study

In 1988, as part of the permitting effort for the helper cooling towers, KBN Engineering performed a detailed deposition modeling analysis to assess the total effects of the two natural draft cooling towers for Units 4 and 5 and the four mechanical draft helper cooling towers for Units 1, 2, and 3. The enclosed Figure 3-2, which is from that KBN report, shows the total predicted salt deposition during the summer months resulting from permitted levels of salt drift from the natural draft and helper cooling towers. The summer season was modeled because the helper cooling towers do not operate from November through April.

The maximum total combined deposition over a naturally vegetated area was predicted to occur near the helper cooling towers, and was approximately 400 g/m^2. The vegetation in this area is mainly comprised of salt marsh, which is very tolerant of atmospheric salt deposition. The predicted deposition levels fall rapidly with distance from the helper cooling towers to a level of approximately 10 g/m^2 at the north property line. Sections 3 and 4 from the KBN report, which discuss the modeling analysis, are also enclosed.

Actual deposition levels are likely much lower than those predicted by the conservative modeling analysis. The drift rate measured from the helper cooling towers was at 8% of the permitted level during the most recent stack test. Indeed the salt deposition at the Open Hammock site, the closest monitoring site to the helper cooling towers, was measured during the 1993-1994 study year to be about 146 kg/ha (14.6 g/m^2, Figure 4-1). In addition, the amount of salt collected at this site during the months that the helper towers were operating was not significantly different than the amount collected during the months when the towers were not operating.

St. Johns River Power Park Study

A salt deposition study was conducted by the Jacksonville Electric Authority and Florida Power and Light to assess the effects of the salt drift from the cooling towers for two 600 MW coal-fired steam electric units at the St. Johns River Power Park (SJRPP). The study period was from February 1986 through September 1989. The study began prior to the operation of the first cooling tower and continued for 18 months after the second tower began operation. As with the Crystal River study, the SJRPP study involved the collection of deposition samples at multiple sites combined with a photographic record of the vegetative effects in the surrounding area.

The SJRPP study found no salt-related injury to the vegetation on or surrounding the plant site. The study was concluded after only 18 months of data were obtained while both cooling towers were in operation.

Scientific Validity

The scientific value of salt deposition studies in coastal areas is questionable. The salt drift from power plant cooling towers is only one variable in a complex system. At the Crystal River plant, natural deposition of salt from the Gulf of Mexico, coastal vegetative dieback from sea level rise, and damage due to disease confound the study results and subsequent data interpretation.

Attachment D

Natural deposition may be quite large from coastal storms. For example, the March 1993 storm deposited such a massive amount of salt on the coastal vegetation that it dwarfs the amount of salt deposited by the operation of the cooling towers. Also, some damage and dieback are occurring along the immediate coastline from the slow sea level rise that is taking place along the west coast of Florida. This coastal dieback is not confined to the Crystal River area, but is occurring along a large portion of the coastline.

Conclusion

FPC, for the following reasons, which have been discussed above, requests that the Crystal River salt drift study be terminated:

- No significant impacts are occurring to the area surrounding the Crystal River plant from the operation of the cooling towers. The study has recorded the effects of the Units 4 and 5 natural draft cooling towers since its inception in 1981. In addition, two full operating seasons of the helper cooling towers have been added to the study results.
- A KBN modeling study showed minimal deposition off FPC plant property from the permitted levels of salt drift. Actual drift is a fraction of the permitted amount.
- The SJRPP study yielded results similar to the Crystal River study, and it was terminated after 18 months of data from both cooling towers.
- The scientific value of the study is limited, and given the 13 year length of the Crystal River study, it has reached its limit in terms of providing additional meaningful data.

Termination of the study would be effective immediately upon approval.

Thank you for your consideration of this request. Please contact David Voigts at (813) 866-5166 or Mike Kennedy at (813) 866-4344 if you have any questions or if you need additional information.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director

Enclosures

cc: EPA Region IV
Ms. Marilyn Polson, Esq.
Mr. Clair Fancy, DEP - Tallahassee

Attachment 1

KBN Modeling Study Results

Attachment D

Table 3-2. Crystal River Units 1, 2 and 3 Tower Specifications and Design Parameters Used in Modeling Analysis of Helper Cooling Towers.

Parameter	Helper Cooling Towers	
	Rectangular	Round
No. Towers/Fans per Tower	4/10	3/12
Fan Height	60 ft. (18.3m)	82 ft.(25.0m)
Fan diameter	28 ft. (8.54m)	28 ft.(8.54m)
Fan Velocity	26.24 ft./s (8.0 m/s)	29.4 ft./s (8.96 ms)
Exit Temperature	91°F (306K)	91°F (306 K)
Tower Plow Rate	687,000 gpm	687,000 gpm
Draft Rate	0.002%	0.002%
Total Dissolved Solids	29,100 ppm	29,100 ppm

Source: McVehil-Monnett Associates, Inc., 1987

Table 3-4. Crystal River Units 4 and 5 Cooling Tower Design Parameters Used in Deposition Modeling Analysis

Parameter	Units 4, 5
Number per Unit	1
Height (ft)	443
Base Diameter (ft)	380
Exit Diameter (ft)	214
Range (deg F)	22.5
Approach (deg F)	17.7
Flow Rate, each (gpm)	331,000
Annual Capacity Factor (%)	81
Circulating Water Total Dissolved Solids Content (mg/l)	32,000

Source: McVehil-Monnett Associates (1988)

~~Attachment D~~

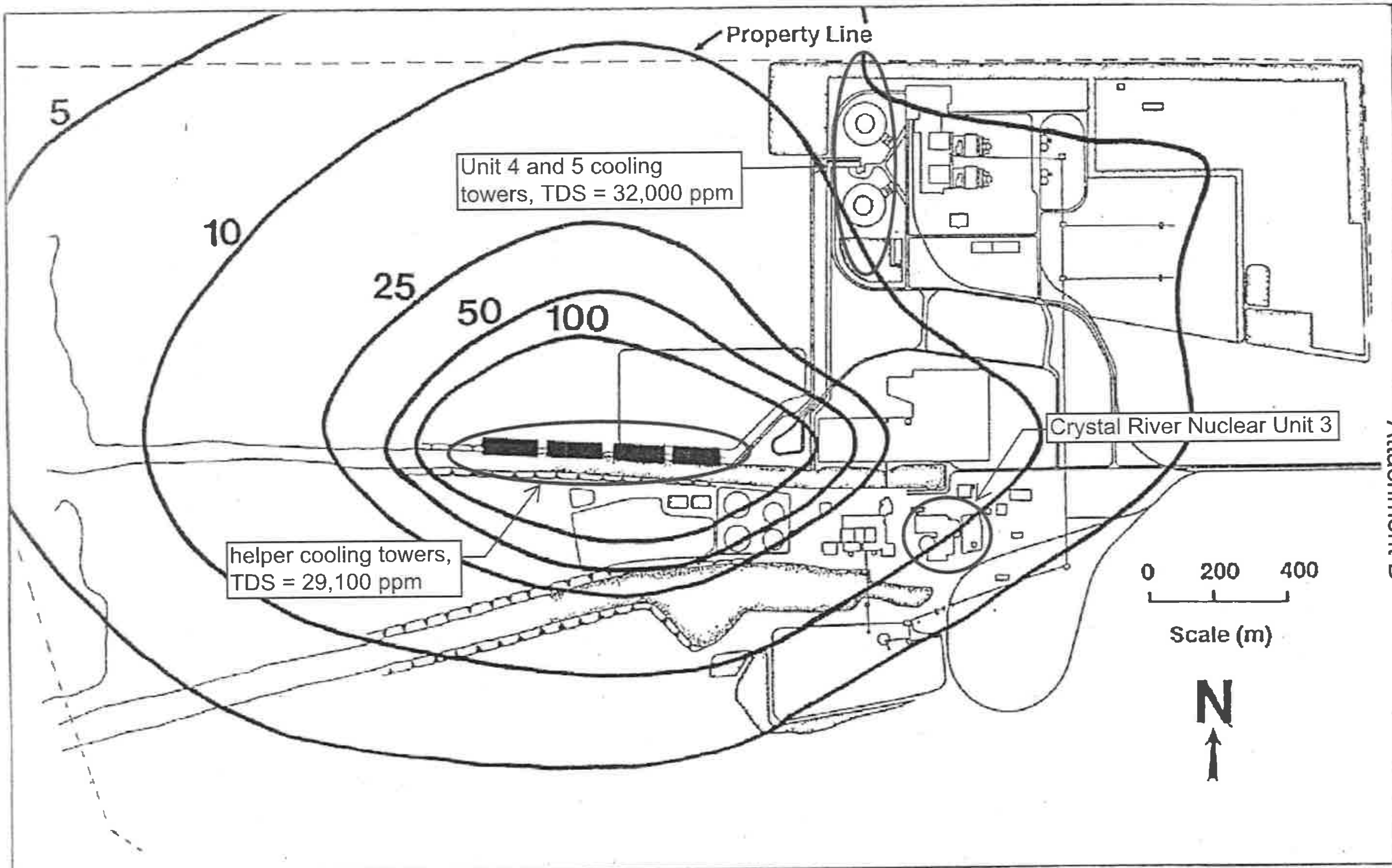


Figure 3-2. Total Summer Deposition of Cooling Tower Drift (g/m^2) - Four Rectangular Draft Towers (Case 1)

Table 1. Availability of Hope Creek Nuclear (seawater cooling tower) and Diablo Canyon Units 1 and 2, 2008 - 2013

Nuclear Plant	Start Date	Capacity, MW	2013 Capacity Factor (Percent)	2012 Capacity Factor (Percent)	2011 Capacity Factor (Percent)	2010 Capacity Factor (Percent)	2009 Capacity Factor (Percent)	2008 Capacity Factor (Percent)	2008-2013 Average Capacity Factor
Hope Creek (NJ), seawater cooling tower	1986	1,178	80%	93%	103%	93%	95%	108%	98%
Diablo Canyon Unit 1	1985	1,073	95%	84%	100%	88%	84%	98%	92%
Diablo Canyon Unit 2	1986	1,087	82%	97%	89%	100%	84%	74%	88%

Table 2. Availability of Hope Creek Nuclear and Diablo Canyon Units 1 and 2, 2010 - 2013

Nuclear Plant	Start Date	Capacity, MW	2013 Capacity Factor (Percent)	2012 Capacity Factor (Percent)	2011 Capacity Factor (Percent)	2010 Capacity Factor (Percent)	2010-2013 Average Capacity Factor
Hope Creek (NJ), seawater cooling tower	1986	1,178	80%	93%	103%	93%	92%
Diablo Canyon Unit 1	1985	1,073	95%	84%	100%	88%	92%
Diablo Canyon Unit 2	1986	1,087	82%	97%	89%	100%	92%

Note 1: Bechtel was architect/engineer/constructor for the Hope Creek Nuclear plant.
Note 2: A refueling outage began at Hope Creek Nuclear on Oct. 12, 2013 and moisture in the main steam turbine caused at plant trip on Dec. 1, 2013.
Note 3: The steam generators in DCPP Unit 2 were replaced in 2008. The steam generators in DCPP Unit 1 were replaced in 2009.

References:
1. NRC Information Digest (NUREG-1350, Volume 26), Sept. 2, 2014. Appendix A: U.S. Commercial Nuclear Power Reactors - Operating Reactors
2. DCPP operational dates and capacities: http://www.energy.ca.gov/nuclear/california.html
3. PSEG Hope Creek Nuclear Fact Sheet: https://www.pseg.com/family/power/nuclear/pdf/hope_creek_factsheet.pdf

Attachment E

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: U24 Cooling Tower
Operating Scenario: OS Summary

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	TSP <= 65.9 tons/yr. [N.J.A.C. 7:27-22.16(a)]	TSP: Monitored by calculations annually rolling one week basis. TSP (TPY) = 0.0022 x D x C x TDS; where D = fraction of circulating water lost to drift = 0.00041% C = circulating water rate (gal/min) = 612,000 gal/min (based on maximum capacity of cooling tower) TDS = total dissolved solids concentration in circulating water (mg/l) A sample of the circulating water will be taken a minimum of every 7 days and analyzed for TDS. [N.J.A.C. 7:27-22.16(o)]	TSP: Recordkeeping by manual logging of parameter or storing data in a computer data system each week during operation Records shall be maintained on site for a period of five (5) years after the date of each record and made available to the representatives of the Department upon request. [N.J.A.C. 7:27-22.16(o)]	Submit a report: Annually beginning on the first day of July, starting 2009. The report shall be submitted to the NJDEP Southern Regional Enforcement Office, NJDEP Bureau of Operating Permits and USEPA Region II for a period of five years from the date of commencement of post-EPU (after thermal uprate) operations of the Hope Creek Generating Station. The report must contain: 1. A log of the total dissolved solids concentration of the circulating water flow. 2. The calculated maximum cumulative (12 month) particulate emissions in tons per year. 3. Description of any maintenance procedures applied to the cooling tower. [N.J.A.C. 7:27-22.16(o)]

TDS = (65.9)/0.0022 x 0.0000041 x 612,000 = 11,938 mg/l

Table 3-17. Salt drift deposition as a function of distance and direction -- winter season

PLUME SALT DEPOSITION TABLE (KG./(KM.**2-MO.))
LINEAR MECHANICAL DRAFT COOLING TOWER -- DUAL LINE ARRAY CONFIGURATION
SEASON=WINTER

DISTANCE FROM TOWER (M)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
WIND FROM / PLUME HEADED	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	6597.	13445.	33690.	22522.	7560.	4470.	5306.	12161.	16159.	16735.	24562.	10585.	3881.	1426.	1142.	1495.	11358.
200.	859.	2025.	4966.	2905.	865.	413.	489.	1155.	1500.	1580.	2707.	1349.	484.	127.	125.	153.	1356.
300.	155.	539.	1319.	806.	162.	68.	81.	233.	355.	456.	778.	361.	92.	32.	37.	43.	345.
400.	65.76	236.79	541.97	309.16	91.64	32.79	62.67	97.84	190.85	157.64	299.27	154.01	40.87	16.29	29.23	31.90	147.42
500.	81.91	154.79	362.48	219.08	82.58	16.82	32.99	43.67	121.40	122.41	220.84	105.97	46.44	8.84	15.61	16.13	103.25
600.	47.55	115.24	280.52	166.44	57.02	12.50	19.93	31.68	94.22	95.23	162.41	76.50	26.54	4.52	6.97	7.49	75.30
700.	35.89	63.74	152.38	88.73	35.35	11.78	17.82	29.86	69.26	44.60	87.70	43.23	20.50	3.82	5.56	6.08	44.77
800.	18.03	46.01	106.28	65.54	18.24	10.58	15.94	27.02	35.83	36.84	69.68	32.67	10.56	3.39	4.43	5.03	31.63
900.	15.63	37.57	86.35	56.74	16.46	7.36	10.31	20.25	30.18	34.60	59.81	26.54	9.05	2.17	2.85	3.43	26.21
1000.	12.97	32.35	74.19	48.30	14.52	5.25	6.90	16.67	27.87	30.74	50.61	22.48	7.02	1.28	2.20	2.50	22.24
1100.	9.52	26.55	64.40	40.68	13.34	5.10	6.46	16.30	24.74	26.79	43.17	18.85	5.80	1.13	1.91	2.21	19.18
1200.	8.38	19.06	49.19	29.87	11.48	4.80	6.13	15.03	22.64	20.09	30.20	13.68	5.19	1.02	1.71	1.93	15.03
1300.	7.22	16.55	41.99	23.96	8.05	4.24	5.79	11.50	18.46	11.94	21.17	10.44	4.43	0.84	1.37	1.51	11.84
1400.	6.19	14.63	38.22	21.84	5.92	3.85	5.19	10.54	13.61	10.28	18.92	9.31	3.51	0.84	1.13	1.28	10.33
1500.	5.66	12.57	32.69	18.97	5.11	2.91	3.87	7.10	9.69	9.47	16.84	8.10	2.94	0.76	0.70	0.93	8.64
1600.	5.39	7.03	17.09	10.74	5.06	2.44	3.19	5.95	9.56	6.84	11.98	5.12	2.90	0.67	0.52	0.81	5.96
1700.	4.86	6.66	16.41	10.21	4.66	2.35	3.12	5.82	9.14	6.30	11.17	4.89	2.66	0.65	0.52	0.79	5.64
1800.	3.81	6.24	15.53	9.48	3.84	2.33	3.11	5.70	7.66	5.68	9.87	4.50	2.13	0.64	0.52	0.77	5.11
1900.	3.10	6.02	14.90	9.14	3.20	2.27	3.10	5.38	6.57	5.38	9.46	4.30	1.78	0.64	0.51	0.74	4.78
2000.	3.07	5.33	13.26	8.40	3.08	2.48	3.39	5.67	6.32	5.10	8.75	3.77	1.74	0.72	0.51	0.79	4.52
2100.	3.04	5.16	12.86	8.13	3.03	2.61	3.56	5.79	6.01	5.01	8.49	3.65	1.71	0.76	0.45	0.75	4.44
2200.	3.62	7.25	19.04	11.27	3.37	2.40	3.24	5.32	6.64	5.89	10.17	4.75	1.93	0.70	0.40	0.69	5.42
2300.	4.44	8.62	23.00	13.28	3.94	2.21	2.98	5.02	7.68	6.47	11.10	5.44	2.25	0.64	0.38	0.65	6.13
2400.	4.27	8.30	22.38	12.80	3.79	2.20	2.98	5.01	7.51	6.31	10.42	5.23	2.12	0.64	0.38	0.64	5.94
2500.	3.68	6.88	18.67	10.62	3.52	2.03	2.72	4.72	7.00	5.37	8.95	4.38	1.93	0.57	0.36	0.60	5.12
2600.	2.71	5.58	14.80	8.24	2.81	1.62	2.12	4.04	5.61	3.85	6.98	3.37	1.43	0.42	0.31	0.49	4.02
2700.	2.52	5.06	13.70	7.48	2.35	1.59	2.09	3.44	4.87	3.20	5.90	3.02	1.36	0.40	0.29	0.46	3.61
2800.	2.49	5.04	13.70	7.48	2.08	1.52	2.08	3.08	4.62	3.06	5.67	3.02	1.34	0.40	0.29	0.46	3.52
2900.	2.41	4.67	12.65	6.94	1.93	1.40	1.97	2.76	3.95	2.84	5.20	2.78	1.27	0.40	0.24	0.37	3.24
3000.	1.72	3.50	9.31	5.24	1.46	1.01	1.45	2.14	2.72	2.33	4.23	2.15	0.91	0.29	0.19	0.26	2.43
3100.	1.64	3.50	9.31	5.24	1.39	0.95	1.37	1.98	2.60	2.33	4.23	2.15	0.87	0.28	0.18	0.24	2.39
3200.	1.64	3.49	9.29	5.23	1.39	0.87	1.22	1.68	2.60	2.32	4.17	2.09	0.87	0.27	0.14	0.24	2.34
3300.	1.64	3.43	9.12	5.17	1.39	0.87	1.21	1.67	2.60	2.31	4.07	2.04	0.87	0.27	0.12	0.23	2.31
3400.	1.64	3.31	8.84	5.05	1.39	0.90	1.23	1.71	2.60	2.28	3.95	2.00	0.87	0.28	0.12	0.23	2.27
3500.	1.64	3.31	8.83	5.04	1.39	0.90	1.23	1.71	2.60	2.28	3.94	2.00	0.87	0.28	0.12	0.23	2.27
3600.	1.45	2.68	7.00	4.12	1.27	0.78	1.06	1.52	2.37	2.00	3.43	1.67	0.78	0.24	0.11	0.20	1.92
3700.	1.18	2.52	6.55	3.89	1.08	0.66	0.89	1.33	2.02	1.92	3.30	1.59	0.65	0.20	0.10	0.17	1.75
3800.	1.16	2.52	6.55	3.89	1.07	0.66	0.89	1.33	1.98	1.92	3.30	1.59	0.59	0.20	0.10	0.17	1.75
3900.	1.12	2.42	6.31	3.71	1.03	0.64	0.87	1.30	1.94	1.86	2.98	1.51	0.57	0.19	0.10	0.17	1.67
4000.	1.12	2.32	6.16	3.57	1.03	0.61	0.85	1.26	1.94	1.79	2.80	1.46	0.57	0.18	0.10	0.16	1.62
4100.	1.12	1.99	5.25	3.07	1.03	0.61	0.85	1.26	1.94	1.59	2.51	1.26	0.57	0.18	0.10	0.16	1.47
4200.	0.73	1.37	3.49	2.15	0.75	0.40	0.54	0.92	1.41	1.33	2.01	0.92	0.37	0.11	0.08	0.11	1.04
4300.	0.63	1.35	3.42	2.09	0.68	0.37	0.50	0.88	1.27	1.29	1.93	0.90	0.32	0.10	0.08	0.10	0.99
4400.	0.61	1.33	3.38	2.06	0.68	0.37	0.50	0.88	1.27	1.27	1.88	0.88	0.32	0.10	0.08	0.10	0.98
4500.	0.60	1.33	3.34	2.02	0.68	0.37	0.50	0.88	1.27	1.20	1.82	0.86	0.32	0.10	0.08	0.10	0.97
4600.	0.55	1.31	3.26	1.92	0.68	0.37	0.50	0.87	1.27	1.03	1.68	0.80	0.32	0.10	0.08	0.10	0.93
4700.	0.55	1.31	3.26	1.92	0.68	0.37	0.50	0.87	1.27	1.03	1.68	0.80	0.32	0.10	0.08	0.10	0.93
4800.	0.53	1.23	3.11	1.82	0.64	0.37	0.50	0.86	1.22	0.91	1.55	0.75	0.31	0.10	0.08	0.10	0.88
4900.	0.52	1.11	2.77	1.64	0.64	0.34	0.48	0.83	1.20	0.85	1.45	0.68	0.30	0.09	0.08	0.09	0.82
5000.	0.36	0.85	2.01	1.26	0.52	0.24	0.33	0.66	0.99	0.74	1.24	0.55	0.22	0.06	0.07	0.07	0.64

source: Engineering and Environmental Science, *USER'S MANUAL: COOLING-TOWER-PLUME PREDICTION CODE (Revision 1) - A computerized methodology for predicting seasonal/annual impacts of visible plumes, drift, fogging, icing, and shadowing from single and multiple sources*, prepared for Electric Power Research Institute, September 1987, Table 3-17, p. 3-32.