BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations	R.23-01-007 (Filed January 14, 2023)

OPENING VERIFIED COMMENTS OF SAN LUIS OBISPO MOTHERS FOR PEACE ON PHASE 1 TRACK 2 ISSUES

June 30, 2023

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VERIFICATION

I am the attorney for San Luis Obispo Mothers For Peace (SLOMFP) in this matter. I make this verification for SLOMFP as I am authorized to do so. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury of the State of California that the foregoing is true and correct.

Executed on the 30th of June, 2023 in Ventura County, California.

__/S/_______________________________________
Sabrina Venskus
Attorney for SLOMFP

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I. INTRODUCTION

These comments respond to Question 1.a. in the ALJ's Ruling dated April 20, 2023. These comments also discuss some of the most rigorous regulatory compliance processes that will need to be undertaken should the California Public Utilities Commission (CPUC) decide to authorize extension of the Diablo Canyon Nuclear Power Plant (DCNPP), and argue that additional costs will be substantial as a result of these regulatory compliance processes, which may include judicial challenges to approvals by other agencies with jurisdiction over DCNPP and its activities. These additional costs must be factored into the CPUC's cost-benefit analysis in determining whether it is cost-effective and prudent to authorize the extension of DCNPP operations.

II. DEFINITION OF "TOO HIGH TO JUSTIFY"

The ALJ's Ruling Requesting Comments Served As Testimony requests comments on how the phrase "too high to justify" should be defined and evaluated in the context of Pub. Util. Code (P.U.C.) § 712.8(c)(2)(B).[1] P.U.C. § 712.8(c)(2)(B) states in relevant part,

> "If the Independent Safety Committee for Diablo Canyon's reports or recommendations cause the commission to determine, in its discretion, that the costs of any upgrades necessary to address seismic safety or issues of deferred maintenance that may have arisen due to the expectation of the plant closing sooner are too high to justify incurring, or if the United States Nuclear Regulatory Commission's conditions of license renewal require expenditures that are too high to justify incurring, the commission may issue an order that reestablishes the current expiration dates as the retirement date, or that establishes new retirement dates that are earlier than provided in subparagraph (A) of paragraph (1), to the extent allowable under federal law, and shall provide sufficient time for orderly shutdown and authorize recovery of any outstanding uncollected costs and fees."

In construing the phrase "too high to justify" the CPUC need not go beyond the first step in statutory interpretation, as the phrase should be given its ordinary and plain meaning.[2]

[1] ALJ's Ruling Requesting Comments Served As Testimony On Statutory Interpretation And Issues Of Policy, And Incorporating Certain Reports Into The Record Of This Proceeding, dated April 20, 2023, p. 4.

[2] *MacIsaac v. Waste Management Collection & Recycling, Inc.* (2015) 134 Cal. App. 4th 1076, 1082-1083.

The Merriam-Webster Dictionary defines "justify" as "to prove or show to be just, right, or reasonable." As the testimony of expert witness Peter Bradford establishes, whether an operator is acting reasonably is equated with the notion of prudence. Accordingly, the plain meaning of the phrase "too high to justify" must mean that costs and expenditures are "too high to justify" if they are unjust, unreasonable or imprudent. Since Senate Bill 846 speaks in terms of statewide matters of concern[3], the analysis of whether a cost or expenditure is too high to justify [i.e., unjust, unreasonable or imprudent] must include analysis of the costs and risks to both PG&E's ratepayers as well as the taxpayers of California.

III. SIGNIFICANT ADDITIONAL COSTS ASSOCIATED WITH REGULATORY COMPLIANCE TO EXTEND OPERATIONS OF DCNPP MUST BE FACTORED INTO THE CPUC'S DECISION-MAKING PROCESS

PG&E will have to comply with multiple federal and state statutes and regulations in seeking to extend operations of DCNPP and will incur significant costs in doing so. The California Natural Resources Agency (CRNA) has issued materials describing these required regulatory approvals.[4] SLOMFP addresses some of these regulatory processes below in more detail.

A. The National Environmental Policy Act

In connection with the Nuclear Regulatory Commission's (NRC) consideration of relicensing DCNPP, the NRC must comply with the National Environmental Protection Act (NEPA). NEPA requires that before a federal agency may take action that may have significant adverse effects on the human environment, that federal agency must evaluate those environmental impacts and "bring those effects to bear" on its decisions.[5] The NEPA process often involves preparation of an Environmental Impact Statement and consultation with NRC

[3] Public Resources Code § 25548(b); P.U.C. § 712.8(c)(2)(D).
[4] https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Transitioning-to-Clean-Energy/Diablo-Canyon-Detailed-Description-and-Plan.pdf
[5] *Natural Resources Defense Council v. NRC*, 685 F.2d 459, 482-83 (D.C. Cir. 1980), rev'd on other grounds, *Baltimore Gas & Electric Co. v. Natural Resources Defense Council*, 462 U.S. 87 (1983). See also *Robertson v. Methow Valley Citizens Association*, 490 U.S. 332, 349 (1989), (environmental impacts must be considered in advance of taking federal action, in order to ensure "that important effects will not be overlooked or underestimated only to be discovered after resources have been committed or the die otherwise cast.")

staff throughout the compliance process.[6] The Environmental Impact Statement prepared by the applicant or the agency itself is a detailed accounting of the environment affected, adverse environmental effects resulting from the proposed action, alternatives to the proposed action, and irreversible and irretrievable commitment of resources involved in the proposed action.[7]

A License Renewal General Environmental Impact Statement ("GEIS") must be prepared to address environmental impacts that are determined to be generic or common to all operating nuclear reactors.[8] This GEIS must be updated every 10 years.[9] In addition, a supplement to the License Renewal GEIS must be prepared to assess reactor-specific environmental impacts, such as those caused by DCNPP.[10] Public and agency comments are received on each draft GEIS and Supplement to GEIS.[11] Responses to Comments are then prepared by the agency and published. A determination on any GEIS and Supplement to GEIS are made via a Record of Decision.[12]

The most current GEIS was issued in 1996 and was revised in 2013.[13] The 2013 Revision to the GEIS is now a decade old. A **draft** second revised GEIS is now pending before the NRC.[14] There are significant deficiencies with the draft second revised GEIS as described by comments from SLOMFP, Beyond Nuclear and the Sierra Club. It is unknown at this time whether the NRC will require revisions and recirculation of the draft GEIS as a result of comments submitted as to the environmental document's insufficiency.

Furthermore, a Supplement to the GEIS that address site-specific issues at DCNPP must also be prepared. The Supplement may recommend additional mitigation measures to reduce environmental impacts to a level of insignificance. Citizens may bring a court action to

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[6] 10 C.F.R. §§ 51.40, 51.41, 51.54, 51.70
[7] 10 C.F.R. § 51.45.
[8] 10 C.F.R. §§ 51.71(d).
[9] 10 C.F.R. Part 51 Subpart A Appendix B.
[10] 10 C.F.R. § 51.95(c).
[11] 10 C.F.R. §§ 51.73 and 51.74
[12] 10 C.F.R. § 51.102 and 51.103
[13] NUREG-1437
[14] 10 C.F.R. § 51.73.

challenge a GEIS' sufficiency under NEPA. NEPA claims are subject to judicial review under 28 USC §1331 and the APA which is 5 USC §702.

B. The Federal Clean Water Act

The Clean Water Act (CWA) is administered by the EPA through the issuance of National Pollutant Discharge Elimination System (NPDES) permits.[15] Under Section 402(b) of the CWA, the EPA has delegated NPDES permitting authority to the California Water Resources Control Board (WRCB).[16] NPDES permits issued by the WRCB "must comply with all minimum federal clean water requirements" and "are issued under an EPA-approved state water quality control program."[17] In administering this EPA-approved program, the WRCB and all other State agencies must acknowledge and apply "the supremacy of federal law."[18]

Section 316 of the CWA requires that "the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts."[19] Based on an exhaustive environmental study as documented in the Final Substitute Environmental Document, the State Water Resources Control Board concluded that for existing power plants including DCNPP, closed cycle wet cooling systems (i.e., cooling towers) constituted the Best Technology Available (BTA).[20] Thus, under the section 316 of the CWA, PG&E should install cooling towers by November 2, 2024 and August 28, 2025, respectively. Powers Engineering has estimated the cost of installing such cooling towers to be approximately $1.5 billion (2023 dollars).[21]

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15 33 U.S.C. § 1251, et seq.

16 See CWA Section 402, 33 U.S.C. § 1342.

17 *Voices of the Wetlands v. State Water Resources Control Board* (2011) 52 Cal. 4th 499

18 Id., 52 Cal. 4th at 521.

19 33 U.S.C. § 1326. See also 2010 Statewide Water Quality Control Policy at 1; Final Substitute Environmental Document, Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling at 1-2 (May 4, 2010) ("2010 Final Substitute Environmental Document").

20 2010 Statewide Water Quality Control Policy https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/cwa316may2010/o tcpolicy_final050410.pdf

21 See Powers Engineering 2023 Update to 2014 Closed-Cycle Cooling Tower Cost Estimate for Diablo Canyon Power Plant, attached as Exhibit A hereto.

A Draft Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (hereinafter "Draft Policy Amendment") is currently under review by the WQCB, which would make "a change without regulatory effect to revise the compliance date for Diablo Canyon Nuclear Power Plant (Diablo Canyon) Units 1 and 2 to October 31, 2030 to comport with the extension provided by Senate Bill 846."[22] The Draft Amendment has received significant public criticism by non-profit organizations such as California Coastkeeper, Sierra Club, as well as SLOMFP.[23] A hearing has yet to be scheduled before the full Board.

Should the WRCB approve the Amendment, it will likely be judicially challenged.[24]

C. The California Coastal Act Federal Consistency Review Process

In addition to the CNRA's description of the federal consistency determination review process[25], the California Coastal Commission (CCC) submitted materials to the CNRA briefly describing the process as well.[26] The CCC has also published a description of the California Coastal Management Program (CCMP)[27], Chapter 11 from the CCMP[28], as well as guide for the application of the Consistency Regulations.[29]

The CCMP is probably the most rigorous regulatory review process pursuant to the Coastal Commission's jurisdiction. If a federally-permitted activity appears on the list of Federal Licenses and Permits Subject to Certification for Consistency[30], then the CCC must perform an analysis of whether the activity is **completely consistent** with the Chapter 3 policies contained in the California Coastal Act.[31] Chapter 3 Policies include, for example, protection of the marine

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[22] Draft Policy Amendment at 18; Draft Staff Report at 12.
[23] Comments of San Luis Obispo Mothers for Peace, Environmental Working Group, and Friends of the Earth on OTC Policy Amendment, dated March 17, 2023 (Exhibit B, attached hereto.)
[24] Cal. Civ. Code of Proc., §§ 1094.5; 1085
[25] See link in footnote 4 above.
[26] https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Transitioning-to-Clean-Energy/2-10-23-Listening-Session.pdf
[27] https://www.coastal.ca.gov/fedcd/ccmp_description.pdf
[28] https://www.coastal.ca.gov/fedcd/ccmp-ch11.pdf
[29] https://www.coastal.ca.gov/fedcd/guidecd.pdf
[30] https://www.coastal.ca.gov/fedcd/listlic_2015.pdf
[31] 15 C.F.R. § 930.53; California Coastal Mgmt Program, Chapter 11; 15 C.F.R. § 930.57(b).

environment [i.e., marine resources, biological productivity and hazardous substance spills]; ensuring public access, protecting and encouraging recreation uses [i.e., protection of certain water-oriented activities oceanfront land and protection for aquaculture use]; protecting visual and scenic resources; and regulating land use so as to discourage development in resource-rich environs [i.e. environmentally sensitive habitats]; and taking into account sea-level rise in its permitting decisions.[32]

No federal license or permit listed in the CCMP can be issued by a federal agency until the CCC concurs with and removes any objection to a consistency certification prepared by the applicant.[33] There is a right of appeal to the U.S. Secretary of Commerce.[34] The federal permitting agency is prohibited from issuing the license or permit unless the objection is overturned by the U.S. Secretary of Commerce on appeal.[35] Permits issued by the NRC for siting and operation of nuclear power plants appears on the list of regulated federally permitted activities.[36] PG&E will undoubtably incur costs as it navigates this process up through and including an appeal to the Secretary of Commerce, if necessary. CCC concurrence determinations are subject to judicial review.[37]

IV. CONCLUSION

The regulatory processes described herein will result in additional substantial costs to PG&E and thus ratepayers. In addition, these regulatory processes insert a considerable amount of uncertainty as to whether PG&E will be able to obtain each and every necessary regulatory approval. Even if the regulatory approvals are obtained, it is probable that conditions of approval will be adopted by the regulatory agency, which may include mitigation requirements that will result in additional costs to PG&E and thus ratepayers. Moreover, the regulatory approvals are subject to judicial challenge which carries with it additional uncertainty should the regulatory approval(s) be found to be an abuse of discretion or *ultra vires* and therefore

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[32] Pub. Res. Code §§ 30200 – 30270.
[33] 16 U.S.C. § 1456; 15 C.F.R. §§ 930.53(d) and 930.54(d)
[34] 15 C.F.R. § 930.63
[35] 15 C.F.R. § 930.64.
[36] 10 C.F.R. §§ 50.82 and 50.83; see also footnote 28.
[37] Pub. Res. Code § 30801; Cal. Civ. Code Proc., §§ 1094.5; 1085

overturned by the court. These are all realities that the CPUC should factor into its decision-making in this case in terms of cost-effectiveness and the prudence of authorizing extension of DCNPP's operation.

June 30, 2023

Respectfully submitted,

____/S/________________________

Sabrina Venskus

Attorney for SLOMFP

EXHIBIT A

Powers Engineering 2023 Update to 2014 Closed-Cycle Cooling Tower Cost Estimate for Diablo Canyon Power Plant

prepared for Friends of the Earth

Bill Powers, P.E., Powers Engineering, May 10, 2023

I. Summary

Powers Engineering (PE) was requested by Friends of the Earth (FOE) in April 2023 to update the cooling tower conversion cost estimates for Diablo Canyon Power Plant (DCPP) originally prepared by PE for FOE in 2014. Table 1 summarizes the 2023 revised cost of ClearSky™ back-to-back closed cycle cooling tower conversions at DPCC. Utility construction costs have increased approximately 48 percent since 2014. The Powers Engineering ClearSky™ back-to-back closed cycle cooling tower conversion cost estimate for Units 1 and 2 at DCPP increased to $1.5 billion in 2023 from $1.2 billion in 2014.

Table 1. Summary of 2023 Powers Engineering comparative cooling tower cost estimates for DCPP, updated from original 2014 cost estimates

Element	SPX/Marley (ClearSky™ back-to-back plume-abated cooling tower manufacturer)	Powers Engineering (Enercon installed cooling tower capital cost[1] with Powers Egr. contingency & outage estimates)	TetraTech
Excavation/civil	463 (generic SPX quote for ClearSky™ on two nuclear units, Attachment B to Powers Engineering Nov. 19, 2013 comments on Bechtel draft DCPP cooling tower report)	492 (SONGS plume-abated cooling towers estimate, Enercon 2009)	213
Piping/other direct costs			261
Cooling towers			61
Engineering/ permitting			included with indirect costs
Indirect costs/ contingency[2]	not included	265 (30%)	360
Cost inflation, 2014-2023 (48%)	not included	363	430

[1] Enercon, *Feasibility Study for Installation of Cooling Towers at San Onofre Nuclear Generating Station*, prepared for Southern California Edison, 2009, Attachment 4, p. 7 of 25. Two-unit DCPP and two-unit San Onofre Nuclear Generating Station (SONGS) are approximately the same capacity. 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. 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). See **Attachment A**.

[2] Ibid. DOE planning contingency range, 20 – 30 percent.

Outage cost[3] (no change, 2014-2023)	not included	392 (24 weeks)	568 (8 months)[4]
Total DCPP cooling tower conversion cost	--	1,512	1,893

In 2014, Powers Engineering estimated the overall cost of ClearSky™ seawater cooling tower retrofits on Units 1 and 2 at DCPP of approximately $1.2 billion.[5,6] This estimated cost included 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).

II. Utility Construction Cost Inflation of 48 Percent, 2014-2023

The magnitude of construction cost inflation from 2014 to 2023 was determined by Powers Engineering by reviewing power and process industry cost trend indexes. Two commonly used price indexes used in the power generation and process industries to forecast cost trends over time are: 1) the Handy-Whitman Index of Cost Trends of Electric Utility Construction, and 2) the Chemical Engineering Plant Cost Index (CEPCI).

The Handy-Whitman Index rose from 672 in 2014 to a projected 992 in 2023.[7] This 2014-2023 increase = 992/672 = 1.48 (48 percent increase).

The CEPCI increased from 576.1 in 2014 to 816.0 at the end of 2022.[8] The 2014-2023 increase = 816.0 ÷ 576.1 = 1.42 (42 percent increase).

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[3] The U.S. EPA estimates the forced outage duration of a nuclear unit cooling tower retrofit from zero weeks (if coordinated with a refueling outage) to 24 weeks [Powers Engineering, *Response to Bechtel Final Addendum: Back-to-Back Seawater Cooling Tower Design/Cost for DCPP Units 1 and 2*, October 30, 2014, p. 8.] The average wholesale price of DCPP replacement power estimated by Bechtel in 2014 was $46.76 per megawatt-hour (MWh). The average wholesale price of power in California remained relatively unchanged between 2014 and 2023 ($47.56/MWh in April 2023).

[4] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, prepared for California Ocean Protection Council, February 2008, Table C-16, p. C-25. TetraTech assumed a net wholesale power cost of $72/MWh over an 8-month DCPP outage. Bechtel assumed the average wholesale power cost in 2014 was $46.76/MWh [Bechtel, *Final Addendum – Addressing the Installation of Salt Water Cooling Towers in the DCPP South Parking Lot*, Sept. 17, 2014, p. 50.]. Current wholesale power cost is ~$46/MWh. $46.76/MWh x 8 months (5,840 hr) x 0.90 x 1,155 MW unit x 2 units = $568 million.

[5] Powers Engineering, *Response to Bechtel Final Addendum: Back-to-Back Seawater Cooling Tower Design/Cost for DCPP Units 1 and 2*, October 30, 2014. See **Attachment B**.

[6] Powers Engineering, *Powers Engineering Response to Bechtel Oral Reply Comments at November 18, 2014 SWRCB Meeting*, December 5, 2014. See **Attachment C**.

[7] PJM, Cost Development Subcommittee - Re: Maintenance Adder Escalation Index Numbers / Escalation Indexes, January 6, 2023: https://www.pjm.com/-/media/committees-groups/subcommittees/cds/postings/handy-whitman-index.ashx.

[8] C. Maxwell, *Cost Indices*, May 3, 2023: https://toweringskills.com/financial-analysis/cost-indices/.

The more conservative Handy-Whitman Index increase of 48 percent from 2014 to 2023 is used in this letter to calculate the updated 2023 capital cost of the cooling tower conversion at DCPP.

III. No Change in Cost of Wholesale Replacement Power, 2014-2023

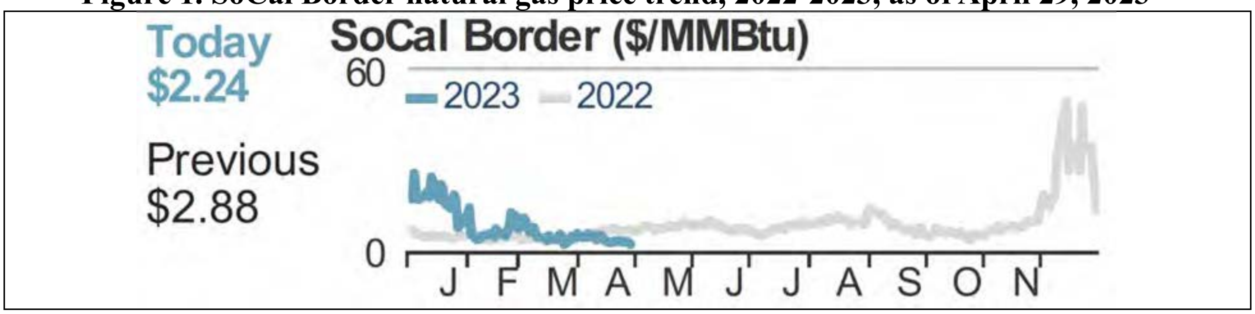
PG&E's closed cycle cooling technical consultant, Bechtel Corporation, assumed a replacement wholesale power cost of $46.76/MWh in its September 2014 assessment of a ClearSky™ back-to-back closed cycle cooling tower conversion at DCPP.[9] There was relatively little change in this average price of wholesale power in the five-year period from 2017 through 2021 as shown in Table 2.

Table 2. Average CAISO wholesale energy costs, 2017-2021[10]

Year	2017	2018	2019	2020	2021	2017-2021 average
Average total energy costs ($/MWh)	39.09	48.47	40.23	41.40	55.52	44.94

The average CAISO wholesale price of electricity is primarily driven by the price of natural gas.[11] A substantial increase in the price of natural gas occurred in the California market in 2022, especially in the second half of 2022. The wholesale natural gas price trend in Southern California in 2022 and in 2023 (through April 2023) is shown on Figure 1. Wholesale natural gas prices returned to long-term average levels in April 2023.

Figure 1. SoCal Border natural gas price trend, 2022-2023, as of April 29, 2023[12]



$/MMBtu = dollars per million British thermal units.

The average wholesale price of electricity in Southern California in April 2023 was $47.56/MWh.[13] This is consistent with the average 2017-2021 average CAISO wholesale energy cost of $44.94/MWh shown in Table 2. Bechtel's assumed 2014 wholesale price of electricity $46.76/MWh remains a reasonable assumption for the price of wholesale power in 2023.

[9] Bechtel, Final Addendum, September 17, 2014, p. 50.
[10] CAISO, *2021 Annual Report on Market Issues and Performance*, July 27, 2022, p. 94, Table 2.1 Estimated average wholesale energy costs per MWh (2017-2021): http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf.
[11] CAISO, *Q4 2022 Report on Market Issues and Performance*, March 16, 2023, p. 1.
[12] EIA, *Southern California Daily Energy Report*, updated April 29, 2023: https://www.eia.gov/special/disruptions/socal/summer/.
[13] EIA, *Wholesale Electricity and Natural Gas Market Data*, April 20, 2023 update, SP15 price hub, weighted average $/MWh price, April 1-18, 2023: https://www.eia.gov/electricity/wholesale/.

IV. Conclusion

The estimated cost of a ClearSky™ back-to-back closed cycle cooling tower conversion on Units 1 and 2 at DCPP increased from $1.2 billion in 2014 to $1.5 billion in 2023.

Signed,

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Attachment A

Enercon Installed Cost Estimate for Plume-Abated Cooling Towers on Units 2 and 3 at San Onofre Nuclear Generating Station

Table 4-1 Engineering and Construction Costs Associated with Conversion to Closed-Loop Cooling at SONGS

The following summarizes the engineering and construction capital cost estimate in 2009 dollars for the implementation of closed-loop cooling at SONGS.

Conversion to Closed-Loop Cooling		
Work Scope	**Estimated Cost**	**Notes:**
Design Engineering and Modification Packages	$ 19,508,000	15% of non-turn-key estimates[1]
Procurement Costs		
Unit 1		
Linear Hybrid Cooling Towers (3)	$ 81,200,000	Attachment 1, Section 1
Noise Abatement	$ 28,420,000	Attachment 1, Section 1
Circulating Water Pumps (3)	$ 6,480,000	Attachment 1, Section 3
Recirculating Water Pumps (3)	$ 13,200,000	Attachment 1, Section 3
Startup Pump (1)	$ 2,160,000	Attachment 1, Section 3
Unit 2		
Linear Hybrid Cooling Towers (3)	$ 81,200,000	Attachment 1, Section 1
Noise Abatement	$ 28,420,000	Attachment 1, Section 1
Circulating Water Pumps (3)	$ 6,480,000	Attachment 1, Section 3
Recirculating Water Pumps (3)	$ 13,200,000	Attachment 1, Section 3
Startup Pump (1)	$ 2,160,000	Attachment 1, Section 3
Subtotal	$ 262,920,000	
Tasks for Closed-Loop Cooling Implementation		
Tunneling	$ 113,935,000	Attachment 2, Section 1 (without spoils removal)
Spoils Removal	$ 8,916,000	Attachment 2, Section 1
Construction / Installation		ENERCON Estimates Below
Civil Costs	$ 18,455,000	(See Below)
Mechanical Costs	$ 26,820,000	(See Below)
Electrical Costs	$ 39,938,000	(See Below)
Power and Control Building	$ 154,000	(See Below)
Field Service Testing, Commissioning, Startup and Training	$ 1,000,000	ENERCON Estimate
Subtotal	$ 209,218,000	
Total Work Scope		
Subtotal	$ 491,646,000	
Recommended Contingency (25%)	$ 122,911,500	DOE Planning Contingency (20-30%)[1]
Recommended Engineering and Construction Budget	**$ 614,558,000**	

1. United States Department of Energy. March 28, 1997. *Cost Estimating Guide.* Publication No. DOE G 430.1-1

Construction / Installation Costs – Civil Estimate

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Construction Estimate
File Name:    civil.est                                          Page:   1
Qty     Craft  Hours Unit          Material      Labor        Equipment     Total
___________________________________________________________________________

Cooling tower basins and footings

Form work
2 uses
37296.00 ax@ 7533.       SF    63,530.01   346,852.80     6,027.03   416,409.84

Reinforcing bar
Grade 60 bars, #3 to #6 bars
566.84   p6@ 7255.      Ton   797,883.98   414,416.72     2,713.69 1,215,014.40

PVC schedule 40 pipe
3/4" (2.5cm) pipe
1509.00  w3@ 45.27       LF       677.24     1,614.63        45.72     2,337.59

Polyvinyl chloride water stop
Center bulb, 3/8" thick x 9" wide
2769.00  al@ 213.2       LF    20,533.24    10,632.96       111.87    31,278.07

Polyvinyl chloride water stop
3/8" thick x 6" wide
16788.00 al@ 1158.       LF    74,488.36    57,750.72       678.24   132,917.31

J-type anchor bolts
3/4" diameter x 18" (46cm) long
1176.00  am@ 588.0       Ea    16,553.38    29,341.20       344.45    46,239.03

Miscellanous Materials
300.00   ee@ 15.00       Ea     1,500.00       501.00         0.00     2,001.00

Placing concrete with a crane and bucket
Slabs on grade 6" (15 cm) or more
34816.40 bs@ 17547       CY 3,622,298.26   746,463.62   204,306.12 4,573,067.99

Placing concrete with a crane and bucket
Add for 4,000 PSI concrete
34816.40 --@ .0000       CY   296,176.15         0.00         0.00   296,176.15

**Subtotal: Cooling Tower Basin
           34356.7          4,893,640.61 1,607,573.65   214,227.12 6,715,441.38

Flume and catch basin

Placing concrete with a crane and bucket
Slabs on grade 6" (15 cm) or more
558.50   bs@ 281.4       CY    58,106.34    11,974.24     3,277.33    73,357.91

Placing concrete with a crane and bucket
Add for 4,000 PSI concrete
558.50   --@ .0000       CY     4,751.05         0.00         0.00     4,751.05

Slab-on-grade edge forms
7" to 12" (18cm to 31cm) high
990.00   av@ 73.26       LF     1,262.25     3,484.80        59.99     4,807.04
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Construction Estimate
File Name: civil.est Page: 2

Qty	Craft	Hours	Unit	Material	Labor	Equipment	Total
Placing concrete with a crane and bucket 12" (31cm) thick building walls							
50.00	bs@	40.90	CY	5,202.00	1,739.50	476.22	7,417.72
Placing concrete with a crane and bucket Add for 4,000 PSI concrete							
608.00	--@	.0000	CY	5,172.13	0.00	0.00	5,172.13
Polyvinyl chloride water stop Plain, 3/8" thick x 9" wide							
990.00	al@	76.23	LF	5,331.74	3,801.60	40.00	9,173.34
Combination section, W shapes and channels 30 to 65 lbs. per LF							
10.40	qm@	73.94	Ton	25,034.88	4,034.16	927.50	29,996.54
Galvanized steel grating 1-1/4" x 3/16", 9.1 lbs. per SF							
5026.50	qc@	266.4	SF	47,681.38	15,531.89	812.28	64,025.55
Steel vertical ladder, primed 20" (51cm)wide, caged							
25.00	qc@	15.95	VLF	2,086.00	928.75	50.00	3,064.75
**Subtotal: Flume and Catch Basin							
		828.2		154,627.78	41,494.94	5,643.32	201,766.03
Plant pump basins							
Condenser basin							
12” thick slab, placed with crane and bucket, wood shores Formwork							
9381.00	BV@	1022.	SF	16,840.77	39,400.20	757.98	56,998.96
12” thick slab, placed with crane and bucket, wood shores, 12' floor-to-floor height Concrete							
9381.00	T7@	469.0	SF	41,910.56	16,135.32	5,116.40	63,162.27
Footing and slab reinforcing Grade 60 bars, #3 to #6 bars							
56.29	p6@	720.5	Ton	79,233.80	41,153.62	269.48	120,656.91
Placing concrete with a crane and bucket Add for 4,000 PSI concrete							
347.44	--@	.0000	CY	2,955.60	0.00	0.00	2,955.60
Polyvinyl chloride water stop Plain, 3/8" thick x 9" wide							
396.00	al@	30.49	LF	2,132.70	1,520.64	16.00	3,669.34
Polyvinyl chloride water stop Plain, 3/8" thick x 9" wide							
200.00	al@	15.40	LF	1,077.12	768.00	8.08	1,853.20
12" concrete walls with two mats of No. 6's at 8" on center, each way, 40’ high Reinforcing steel							
792.00	RI@	2344.	LF	88,054.56	93,614.40	4,055.59	185,724.55

Construction Estimate
File Name: civil.est Page: 3

Qty	Craft	Hours	Unit	Material	Labor	Equipment	Total
12" concrete walls with two mats of No. 6's at 8" on center, each way, 40' high							
Forms							
792.00	B2@	3421.	LF	33,363.79	133,531.20	5,919.41	172,814.40
12" concrete walls with two mats of No. 6's at 8" on center, each way, 40' high							
Concrete							
792.00	B3@	2090.	LF	81,591.84	76,404.24	15,918.41	173,914.49
Cooling tower return basin							
12" thick slab, placed with crane and bucket, wood shores							
Formwork							
8242.50	BV@	898.4	SF	14,796.94	34,618.50	665.99	50,081.43
12" thick slab, placed with crane and bucket, wood shores, 12' floor-to-floor height							
Concrete							
8242.50	T7@	412.1	SF	36,824.19	14,177.10	4,495.46	55,496.75
Footing and slab reinforcing							
Grade 60 bars, #3 to #6 bars							
49.46	p6@	633.0	Ton	69,619.90	36,160.21	236.78	106,016.89
Placing concrete with a crane and bucket							
Add for 4,000 PSI concrete							
305.28	--@	.0000	CY	2,596.96	0.00	0.00	2,596.96
Polyvinyl chloride water stop							
Plain, 3/8" thick x 9" wide							
420.00	al@	32.34	LF	2,261.95	1,612.80	16.97	3,891.72
Polyvinyl chloride water stop							
Plain, 3/8" thick x 9" wide							
100.00	al@	7.700	LF	538.56	384.00	4.04	926.60
12" concrete walls with two mats of No. 6's at 8" on center, each way, 25' high							
Reinforcing steel							
430.00	RI@	1272.	LF	47,807.40	50,826.00	2,201.90	100,835.30
12" concrete walls with two mats of No. 6's at 8" on center, each way, 25' high							
Forms							
430.00	B2@	1857.	LF	18,114.18	72,498.00	3,213.82	93,826.00
12" concrete walls with two mats of No. 6's at 8" on center, each way, 25' high							
Concrete							
430.00	B3@	1135.	LF	44,298.60	41,482.10	8,642.57	94,423.27
Combination section, W shapes and channels							
100 to 500 lbs. per LF							
351.25	qm@	375.8	Ton	512,333.25	20,505.98	4,718.34	537,557.57
Galvanized steel grating							
1-3/4" x 3/16", 12.5 lbs. per SF							
17623.50	qc@	1251.	SF	222,902.03	72,785.06	3,915.94	299,603.02
Misc. components							
5000.00	--@	.0000	Ea	8,750.00	0.00	0.00	8,750.00

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Construction Estimate
File Name:    civil.est                                         Page:   4
Qty    Craft  Hours Unit         Material      Labor        Equipment    Total
___________________________________________________________________________

**Subtotal: Plant basins
           17991.0          1,328,004.69   747,577.36    60,173.17 2,135,755.22

Plume abatement booster pump

Placing concrete with a crane and bucket
Slabs on grade 6" (15 cm) or more
74.00    bs@ 37.29        CY      7,698.96     1,586.56       434.24     9,719.76

Pre-engineered metal buildings - 14' eave height
40 x 100, 4,000 SF (372m2)
1.00     qi@ 280.0        Ea      9,159.60    15,340.00     2,403.80    26,903.40

Valve Pit

12" concrete walls with two mats of  No. 6's at 8" on center, each way, 30' high
Reinforcing steel
3600.00  RI@ 532.8        SF     20,049.12    21,276.00       909.00    42,234.12

12" concrete walls with two mats of  No. 6's at 8" on center, each way, 30' high
Forms
3600.00  B2@ 777.6        SF      7,564.32    30,348.00     1,345.32    39,257.64

12" concrete walls with two mats of  No. 6's at 8" on center, each way, 30' high
Concrete
3600.00  B3@ 475.2        SF     18,470.16    17,352.00     3,636.00    39,458.16

Placing concrete with a crane and bucket
Add for 4,000 PSI concrete
133.33   --@ .0000        CY      1,134.21         0.00         0.00     1,134.21

Placing concrete with a crane and bucket
Slabs on grade 6" (15 cm) or more
32.00    bs@ 16.12        CY      3,329.28       686.08       187.78     4,203.14

Placing concrete with a crane and bucket
Add for 4,000 PSI concrete
32.00    --@ .0000        CY        272.22         0.00         0.00       272.22

Footing and slab reinforcing
Grade 60 bars, #3 to #6 bars
5.10     p6@ 65.28       Ton      7,178.76     3,728.61        24.42    10,931.79

___________________________________________________________________________

Total Manhours, Material, Labor, and Equipment:
           55360.2          6,451,129.71 2,486,963.19   288,984.17 9,227,077.07

Construction Estimate
File Name:    civil.est                                         Page:   8
Qty    Craft  Hours Unit         Material      Labor        Equipment    Total
___________________________________________________________________________

                                  Subtotal:                         9,227,077.07


                            Estimate Total:                         9,227,077.07
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Attachment B

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

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

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[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.

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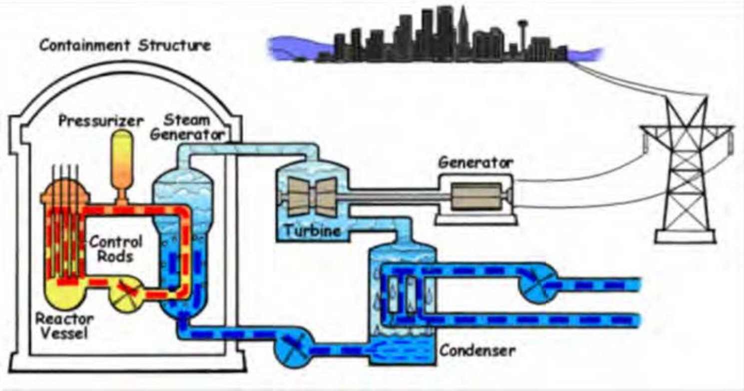
[6] The net DCPP capacity is 2,150 MW. The net SONGS capacity was 2,200 MW prior to the permanent retirement of SONGS in June 2013.
[7] The Enercon March 2009 DCPP cost estimate is more four times higher, at $2.241 billion, than the Enercon cost estimate of $492 million for the SONGS cooling tower retrofit. 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.

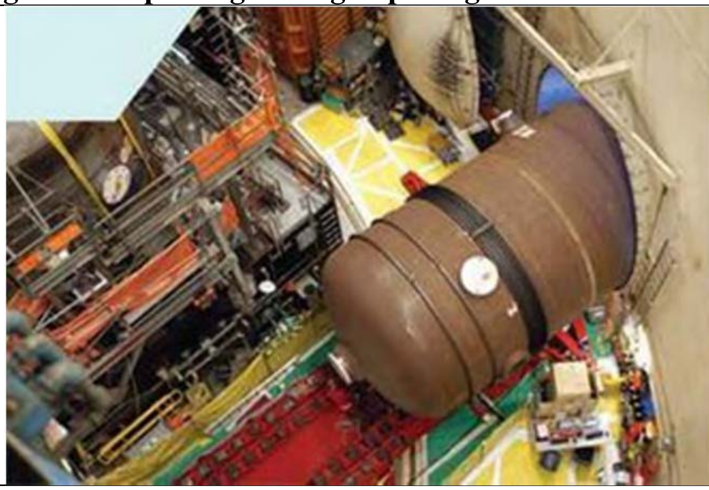
The downtime required for piping hook-ups at U.S. power plants that have been retrofit to cooling towers has generally been one month or less. Units 1 and 2 undergo 30- to 45-day refueling outages approximately every two years. An unscheduled outage of one month beyond the duration of the refueling outage 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.

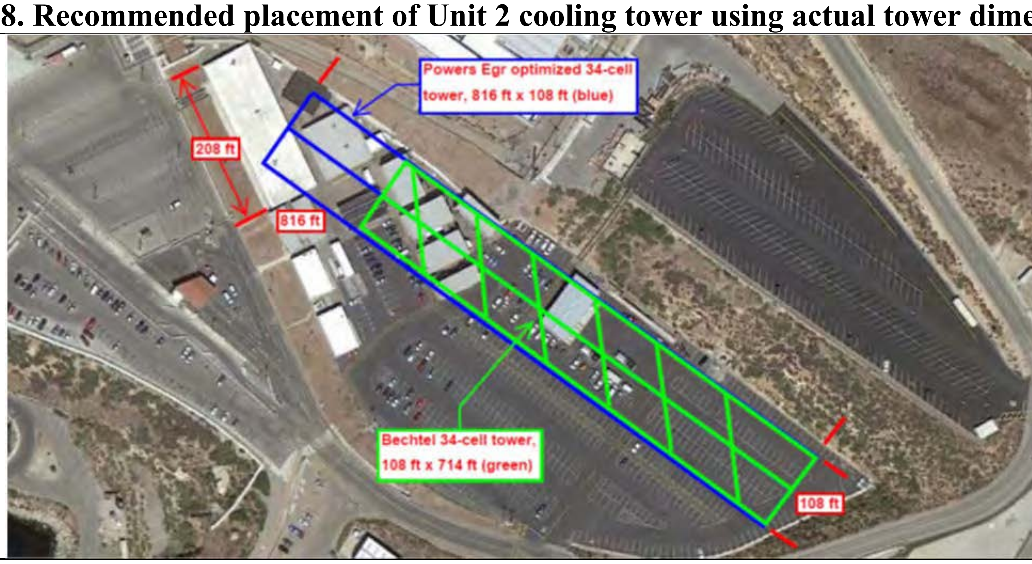
[37] The manufacturer, SPX, provides length and width in six-foot increments in its cooling tower model numbers. "9" means 9 × 6 feet = 54 feet, and "7" means 7 × 6 feet = 42 feet.

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.

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[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.

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[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**.

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.

Figure 10. Hope Creek Cooling Tower[56]

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]

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[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.

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[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

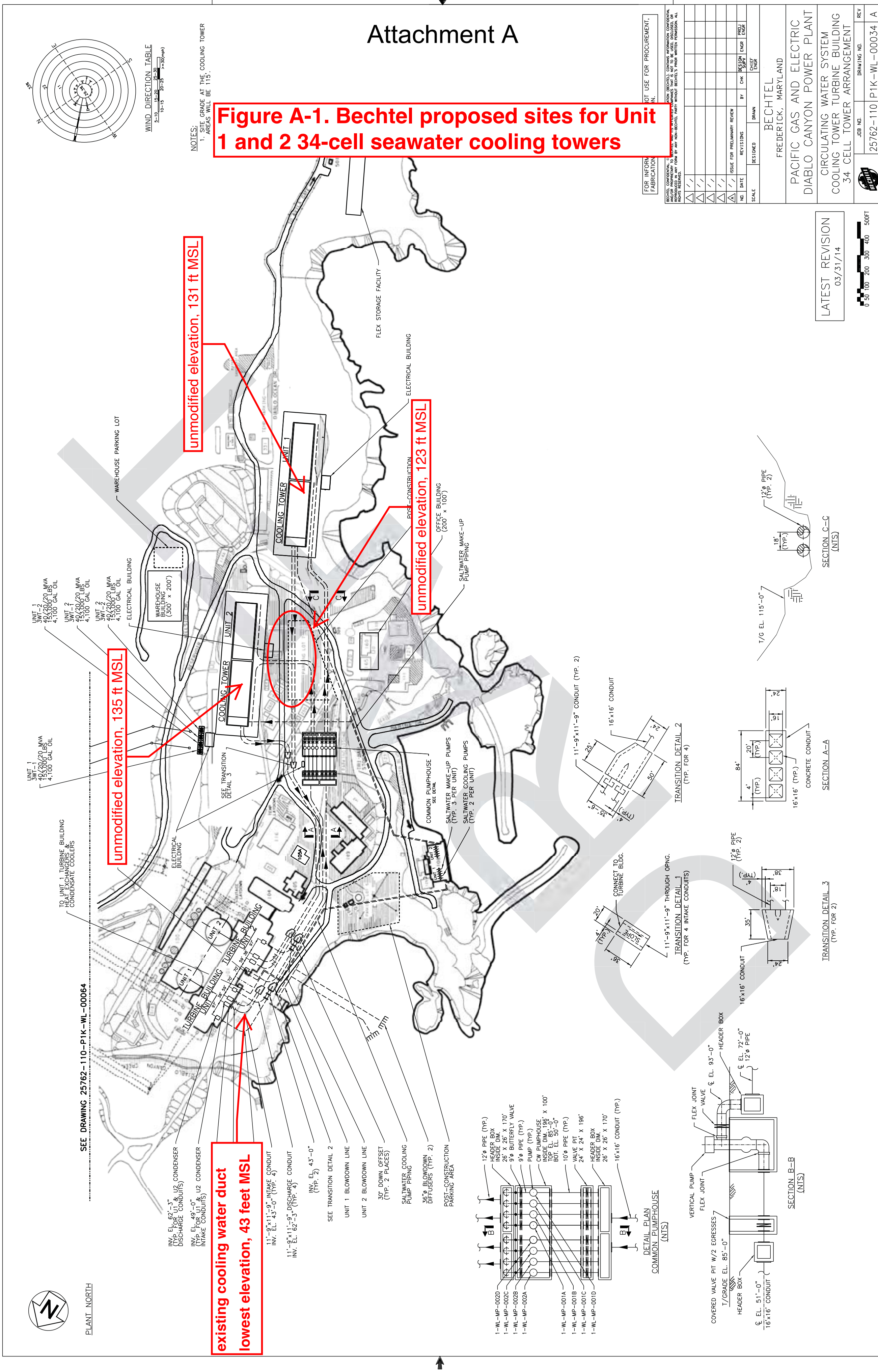

Figure A-1. Bechtel proposed sites for Unit 1 and 2 34-cell seawater cooling towers

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

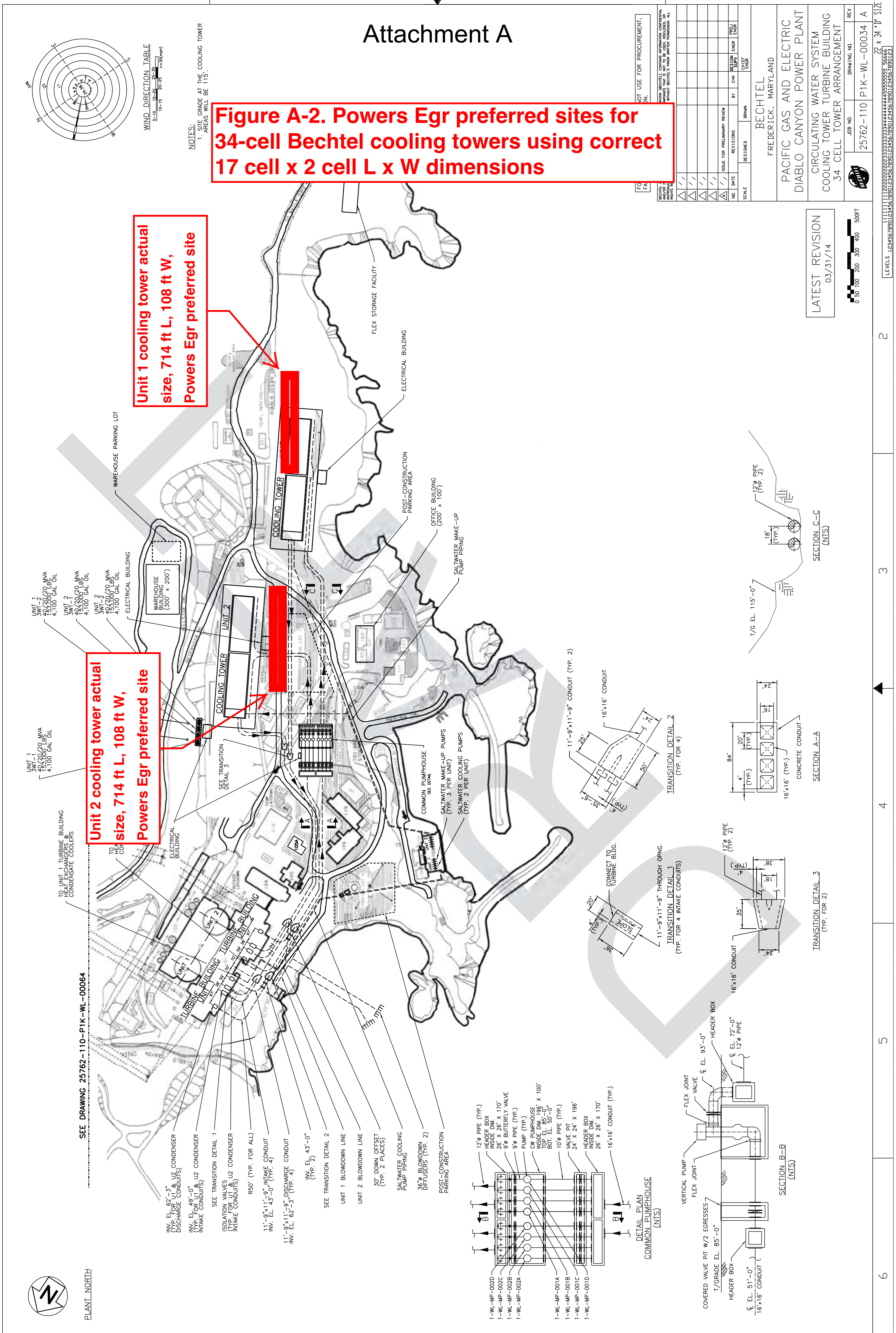

Figure A-3. Bechtel simulation of 34-cell seawater cooling towers for DCPP Units 1 and 2 (Sept. 17, 2014 Final Addendum)

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.

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

Month	Average wet bulb (^oF)	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).

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%

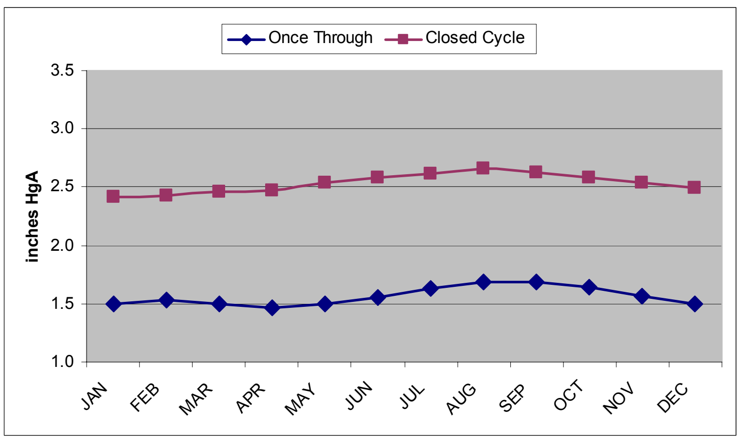

Figure C–9. Estimated Backpressures (Unit 1)

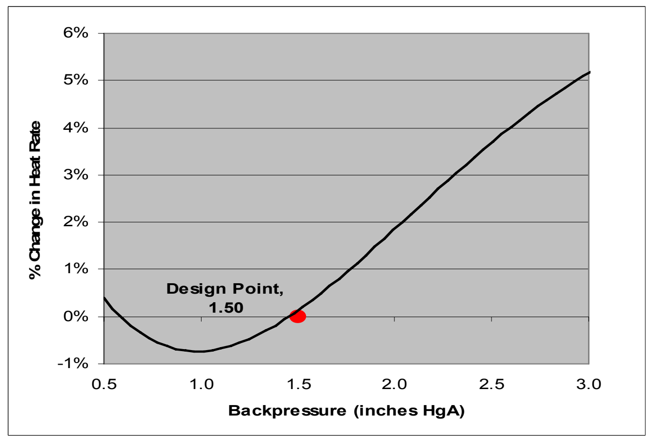

Figure C–10. Estimated Heat Rate Correction (Unit 1)

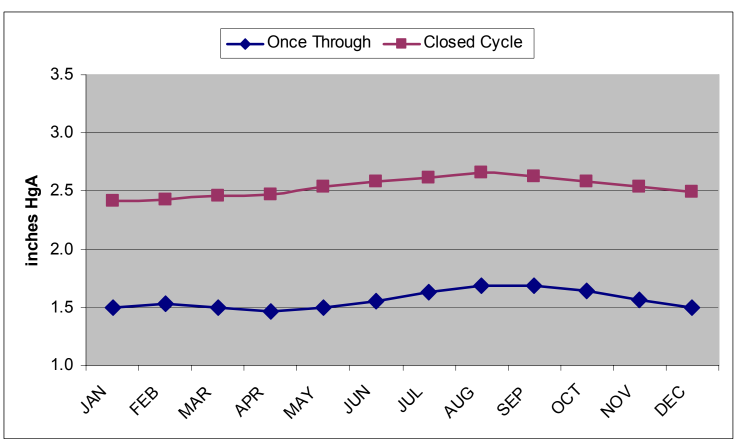

Figure C–11. Estimated Backpressures (Unit 2)

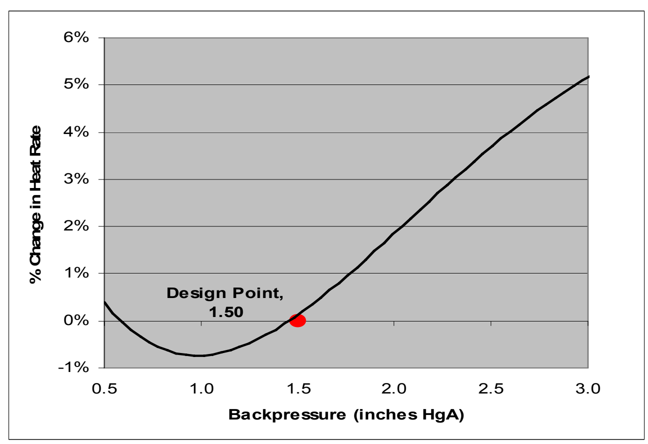

Figure C–12. Estimated Heat Rate Correction (Unit 2)

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

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

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 ^oC HWT, 35^oC CWT, and 32 ^oC WBT was selected for life-cycle cost analysis. Such a tower would

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

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

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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

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)

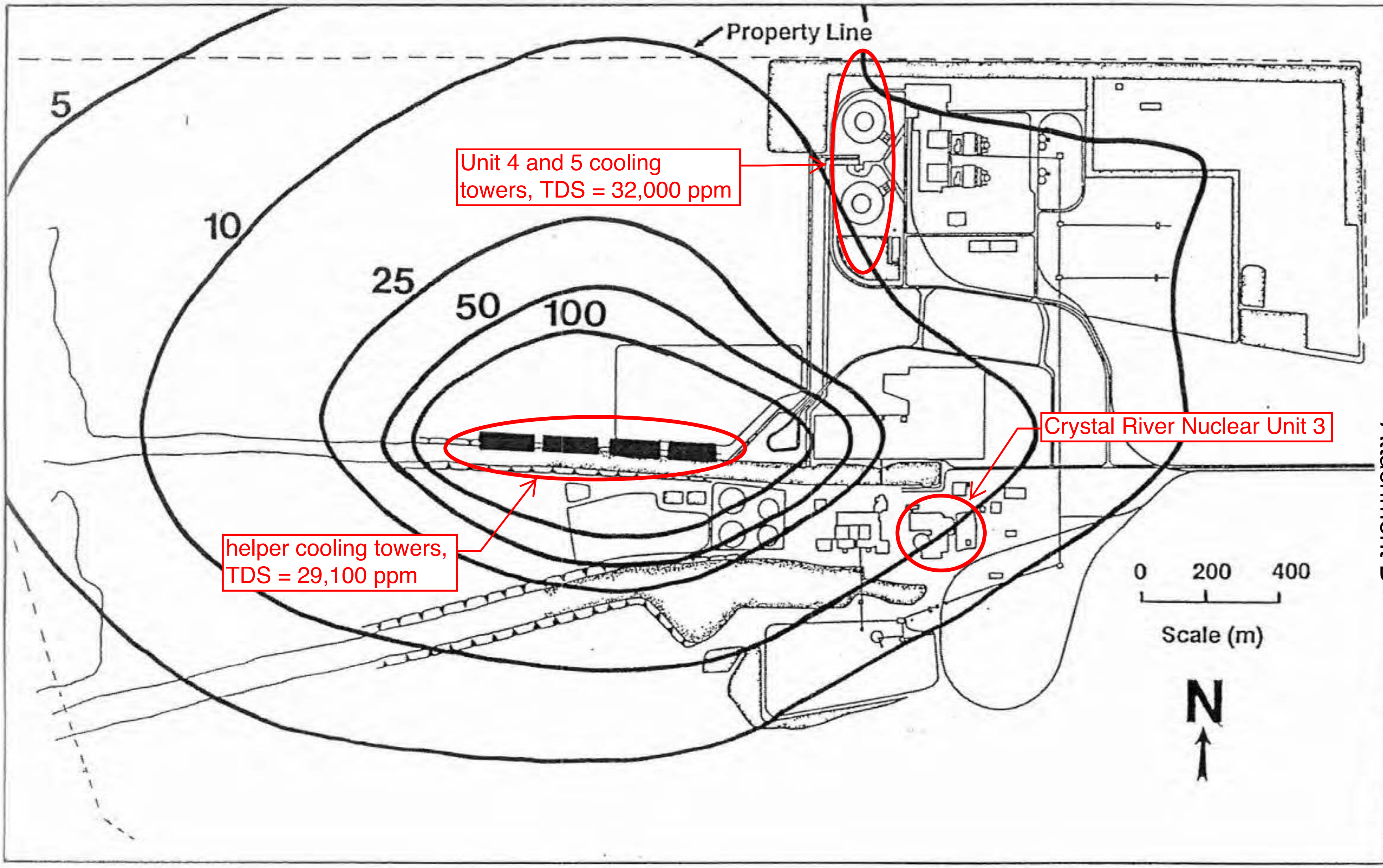

Figure 3-2. Total Summer Deposition of Cooling Tower Drift (g/m^2) - Four Rectangular Draft Towers (Case 1)

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

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)]

$$\boxed{TDS = (65.9)/0.0022 \times 0.0000041 \times 612{,}000 = 11{,}938 \text{ mg/l}}$$

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)	WIND FROM: N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
	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.

Attachment C

December 5, 2014 Powers Engineering
Response to Bechtel Oral Reply Comments at
November 18, 2014 SWRCB Meeting

Powers Engineering Response to Bechtel Oral Reply Comments at November 18, 2014 SWRCB Meeting

prepared for Friends of the Earth

Bill Powers, P.E., Powers Engineering, December 5, 2014

Powers Engineering and Bechtel agree on the direct cost of approximately $400 million to install the seawater cooling towers, and associated circulating water piping and pumps (mechanical, piping, and electrical direct costs), on Units 1 and 2 at Diablo Canyon Power Plant (DCPP).

Powers Engineering and Bechtel do not agree on the need to reduce the elevation of the DCPP south parking lot area to 115 feet MSL, which would add about $1 billion in direct cost to the project. Bechtel asserts that pressure limitations in the existing circulating water ducts under the DCPP turbine building require this action. Powers Engineering asserts the existing circulating water ducts are either already capable of withstanding the increased water pressure that would be imposed by the cooling towers, or can be readily upgraded to withstand the higher pressure with low-cost liners. The hydraulic pressure can also be reduced to appropriate levels with pressure reduction valves to avoid making any modifications to the existing circulating water ducts.

Powers Engineering and Bechtel do not agree on the need for the 2.3 year dual outage assumed by Bechtel in its cost estimate. The long outage is the artifact of Bechtel's choice of an inefficient and high impact closed cycle circulating water duct design strategy west of the DCPP turbine building, and the unsupported presumption that any civil work west of the DCPP turbine building would require a dual outage. A strategy that maximizes use of the existing circulating water ducts west of the DCPP turbine building would largely eliminate the outage duration assumed by Bechtel.

Bechtel representatives contested a number of specific points in the Powers Engineering PowerPoint presentation critiquing Bechtel's September 17, 2014 Final Addendum in oral reply comments at the end of the November 18, 2014 SWRCB meeting. This letter responds to the points raised by Bechtel in its oral reply comments. The principal points raised by Bechtel, and a summary of the Powers Engineering responses, are:

1. The Unit 1 and 2 circulating water ducts in the vicinity of the turbine building are surrounded with a massive amount of reinforced concrete and therefore not easily accessed to upgrade the pressure rating of the ducts to 50 psig.

   Powers Engineering Response 1: Bechtel has provided no documentation to support its contention that the circulating water ducts are not already designed to withstand 50 psig. If these ducts are not capable of withstanding 50 psig, the interior of the ducts can be lined with steel, as proposed by URS for a cooling tower retrofit at Oyster Creek Nuclear, or coated with composite fiber-reinforced polymer to achieve a 50 psig rating. Continuous pressure reduction valves can also be installed upstream of the duct section(s) of concern to maintain pressure within existing design limits.

2. Non-nuclear plant outage time for cooling tower retrofits is not representative of the outage time necessary for nuclear plant cooling tower retrofits.

   Powers Engineering Response 2: Bechtel provides no evidence to support this claim. Bechtel states without comment or justification that it will carry-out all circulating water duct construction west of the DCPP turbine building during an outage. This drives Bechtel's 2.3 year dual outage time estimate. Most of the circulating water duct construction can take place west of the turbine building with DCPP online. In contrast, URS projected a 150-day outage for a cooling tower retrofit at Oyster Creek Nuclear. This outage duration was defined by the time necessary to install steel liners in the existing circulating water ducts at Oyster Creek Nuclear to increase the duct pressure rating to 50 psig. If this task were not necessary, the outage duration estimate for Oyster Creek Nuclear would be considerably reduced.

3. Powers Engineering is wrong regarding the length and width dimensions of the cooling tower cells specified by SPX Cooling Technologies, Inc. for the 34- and 44-cell ClearSky™ seawater cooling towers proposed for DCPP.

   Powers Engineering Response 3: Bechtel is incorrect in asserting the width of the cooling cell in the ClearSky™ cooling tower specification provided by SPX is 60 feet. It is 54 feet. Powers Engineering is incorrect in asserting the length of the cell in the SPX specification is 42 feet. It is 56 feet. If the 60 feet cell width stated by Bechtel is assumed for cooling tower design purposes, the cell length can be reduced to maintain similar cooling tower cross-sectional area and performance compared to the SPX basecase. This shorter, wider cooling tower design is a better fit for the candidate DCPP parking lot sites.

4. Although Palisades Nuclear Plant was originally designed for once through cooling (OTC) operation, it was retrofitted with cooling towers prior to opening.

   Powers Engineering Response 4: Bechtel is wrong. Palisades Nuclear Plant operated for a year-and-a-half as an OTC plant before being shut down for repairs and conversion to closed-cycle cooling.

5. Palo Verde Nuclear Generating Station does not use salt water and therefore is not a relevant example when evaluating salt deposition from seawater cooling towers at DCPP.

   Powers Engineering Response 5: The total dissolved solids ("salts") in the circulating cooling water at Palo Verde are concentrated to near seawater concentration levels in the cooling towers. The estimated salt drift from the Palo Verde cooling towers is similar to the amount of salt drift projected for the DCPP seawater cooling towers. The Palo Verde experience with cooling tower salt deposition is relevant to DCPP.

Detailed support for each Powers Engineering summary response is provided in the following pages of this response letter.

1. 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 to withstand approximately 50 psig service (115 feet hydraulic pressure) at the point where the circulating water pumps discharge into the circulating water ducts.[1] See **Attachment A**. No technical documentation has been provided by Bechtel to support its oral assertion in comments made at the end of the November 18, 2014 SWRCB meeting that the existing circulating water ducts in the vicinity of the turbine building have a design pressure rating of 25 psig.[2]

Bechtel states that 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.[3] Bechtel goes on to state that this higher pressure (50 psig) is limited by the circulating water duct design that forms part of the DCPP turbine building.[4]

The low point in the existing circulating water ducts is 43 feet MSL located underground in front of the DCPP turbine building.[5] 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 135 feet MSL (Unit 2) and 131 feet MSL (Unit 1) unmodified cooling tower elevations at the locations proposed by Bechtel.

Enercon conducted a cooling tower retrofit study for DCPP in 2009 under contract to PG&E.[6] Enercon proposed to increase the Unit 1 and 2 surface condenser pressure limits to 45 psig. Enercon makes no mention of any need to upgrade the circulating water ducts to achieve a 45 psig pressure rating. This indicates the circulating water ducts under the turbine building are already rated at or above 45 psig. Enercon states:[7]

> The tube side of the existing main condensers (tubes, waterboxes, and transition pieces) is designed for 25 psig. Due to the height and location of the cooling towers, the new pressure in the waterbox would be on the order of 45 psig, necessitating strengthening or replacement of the waterbox. . . . The transitions

[1] 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, Figure 2-6: Pressure-Time Profile for the Diablo Canyon Power Plant Cooling Water System, p. 2-10. See **Attachment A**.

[2] Operating pressure in the circulating water ducts immediately upstream of the surface condensers, at an elevation of approximately 60 feet MSL, is less than 20 psig, as shown in **Attachment A**. However, Bechtel has provided no information to support its assertion that the circulating water ducts themselves are designed for lighter pressure duty near the surface condensers than at the outlet of the circulating water pumps.

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

[4] Ibid.

[5] Bechtel drawing, PG&E Diablo Canyon Power Plant, Circulating Water System Cooling Tower Turbine Building 34-Cell Tower Arrangement, Latest Revision March 31, 2014.

[6] Enercon Services, Inc., *Diablo Canyon Power Plant Cooling Tower Feasibility Study*, March 2009, p. 21.

[7] Ibid.

from the buried conduits (circulating water ducts) to the waterboxes would also be upgraded to withstand the increase in pressure.

Enercon does not include the buried circulating water ducts themselves within the scope of components it identifies as requiring an upgrade to achieve a pressure rating of 45 psig. Bechtel must support with engineering documents its assertion that the design pressure limit of the circulating water ducts in the vicinity of the turbine building is less than 50 psig.

Even a 45 psig circulating water system pressure rating is sufficient to avoid any need to lower the unaltered cooling tower site elevations of 131 feet and 135 feet MSL to 115 feet MSL.[8] 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.

2. Even if the current pressure rating of the circulating cooling water ducts was not adequate, off-the-shelf options are available to increase pressure rating or reduce water pressure to acceptable levels

a. Steel liners can be added to the interior of the existing circulating water ducts to increase the pressure rating

Steel liners can be added to the interior of the existing cooling water ducts to increase the pressure rating For example, the rectangular circulating water flumes (ducts) at 645 MW Oyster Creek Nuclear (NJ) were originally design to withstand up to 47 feet of hydraulic head (20 psig).[9] URS proposed installing steel liners in the interior of the flumes to increase the pressure rating of the flumes to 115 feet of hydraulic head (50 psig) to withstand additional hydraulic pressure that would imposed by a retrofit cooling tower.[10] The flumes would be reinforced by installing ¾-inch steel plate liner on the interior walls of the flumes.

If the existing DCPP circulating water ducts required steel liners to achieve a 50 psig pressure rating, the steel liners would be attached to the interior walls of the Unit 1 and 2 circulating water ducts. Access to the interior of the circulating water ducts could be gained either through the surface condenser transition ductwork, or at the point where the circulating water ducts are cut to allow tie-in to the new circulating water pipes from the seawater cooling towers. Figure 1 shows the cross-section of the Unit 1 and 2 circulating water ducts during the construction phase, as well as the location of steel liners if they were to be installed.

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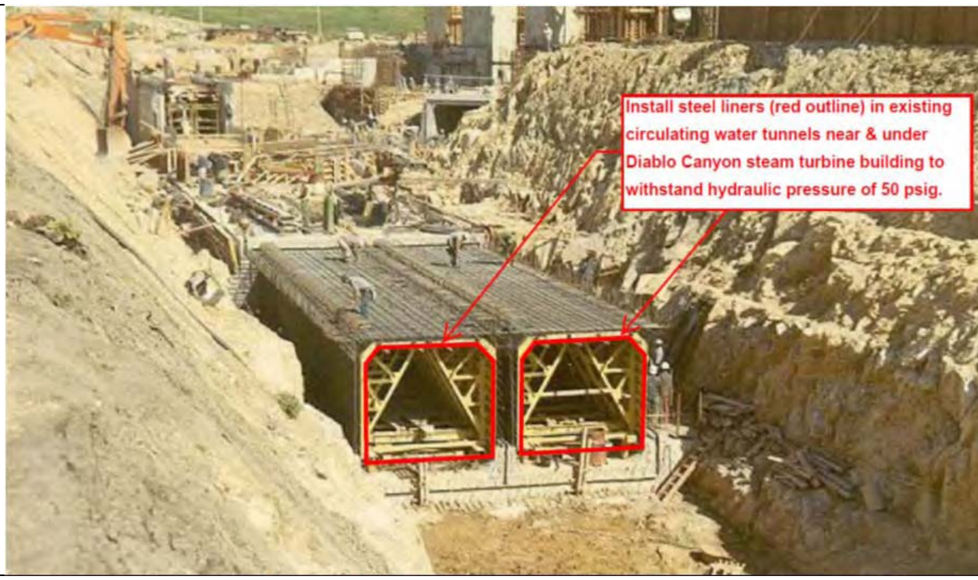
[8] 45 psig equals 103.5 feet of water column. The lowest elevation in the existing circulating water ducts is 43 feet MSL. Therefore, any cooling tower location with a base elevation equal to or less than: 103.5 feet + 43 feet = 146.5 feet MSL will assure the water pressure in the circulating water system does not exceed 45 psig.
[9] URS, *Determination of Cooling Tower Availability for Oyster Creek Generating Station, Forked River, New Jersey*, prepared for Amergen Energy Company, LLC, March 2, 2006, p. 4-3.
[10] Ibid, p. 4-3.

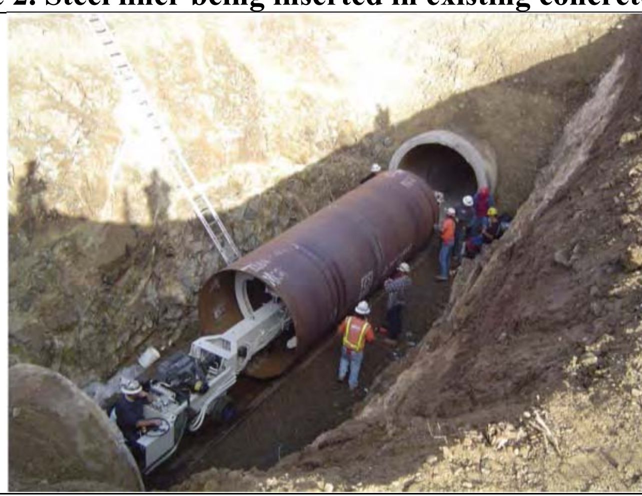
Figure 1. Cross-section of Unit 1 and 2 circulating water ducts showing proposed steel liner locations[11]



It is important to underscore that all work will take place <u>inside</u> the existing circulating water ducts. Bechtel's assertion that the massive amount of reinforced concrete on the outside of the circulating water ducts under the turbine building prevents upgrading the circulating water ducts is not relevant to a project that will take place exclusively on the inside of the circulating water ducts.

A photograph of a steel liner being installed in an existing circular concrete water pipe is shown in Figure 2.

Figure 2. Steel liner being inserted in existing concrete pipe[12]



[11] Enercon, *Diablo Canyon Power Plant Cooling Tower Feasibility Study*, March 2009, p. 19. Red outlines and tag added by B. Powers.

[12] A. Gnesa – Infrastructure Engineering Corporation, J. Neely and L. Rega – San Diego County Water Authority, *Design Methods for Steel Liners to Prevent Collapse by External Pressure During Relining of Pre-stressed Concrete Cylinder Pipe*, presented at Pipelines 2004 International Conference, August 2004, Figure 1, p. 2.

b. Steel liners can be added with an outage of less than six months and at low cost

URS estimated 150 days of outage time would be necessary to line the existing flumes with steel plates.[13] It is this project that establishes the URS total outage time estimate for the cooling tower retrofit at Oyster Creek Nuclear of 150 days.[14] The cost of the steel liner installation to uprate the existing circulating water flumes to 50 psig at Oyster Creek was estimated by URS at $20 million.[15]

The outage time would be substantially less than 150 days if steel liners are not required. The other activity identified by URS that require an outage at Oyster Creek is the interconnection of existing circulating water ducts with newly installed piping and upgrading of the surface condensers.

The activities that require an outage to complete at DCPP, with the exception of the surface condenser upgrade, are shown in **Attachment B**.[16] These activities consistent of: 1) duct transitions at the existing discharge structure to new circulating water ducts connecting to the Unit 1 and 2 cooling tower pump stations, 2) connection of cooling tower return piping to the existing Unit 1 and 2 circulating water ducts in front of the turbine building, and 3) cross-over of the new circulating water ducts over the existing circulating water ducts that will be decommissioned.

These are straightforward construction activities common to all power plant cooling tower retrofits. These tie-in activities were carried-out during an outage of approximately four weeks at the 1,589 MW Brayton Point Station in 2012.[17] The 2008/2009 steam generator replacement projects on DCPP Units 1 and 2 were far more technically complex than cooling tower circulating water duct tie-in activities would be and required outages of only about two months each.[18]

Bechtel presumes that all new circulating water duct construction west of the turbine building must take place with the plant shut down, while offering no justification to support a circulating water duct design that could plausibly result in a multi-year shutdown of DCPP. Almost all of the duct construction activity west of the turbine building, assuming a duct configuration optimized to minimize tie-in downtime, can take place with DCPP online, as outlined in **Attachment B**. Bechtel asserts that each day of dual outage at DCPP will cost approximately

[13] Ibid, p. 4-3.
[14] Ibid, p. E1.
[15] Ibid, Appendix B – Capital and Operating Cost Analysis, p. B-2. 80,000 square feet of sandblasting is included in the steel liner budget. The interior dimensions of the Diablo Canyon circulating water ducts are 11.75 ft × 11.75 ft. Therefore the interior duct perimeter is: 4 x 11.75 ft = 47 ft. 80,000 square ft of liner area would cover: 80,000 ft^2 ÷ 47 ft = 1,702 linear ft of the interior surface of Unit 1 and 2 circulating water ducts at Diablo Canyon.
[16] The outage time required for a surface condenser upgrade is brief, as little as two days per unit. See: EPA, *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002, p. 4-9.
[17] Powers Engineering, *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, October 30, 2014, p. 9.
[18] Ibid, p. 7.

$2.6 million in replacement power purchases.[19] Given the financial impact of outage days, specification of an efficient circulating water duct construction and tie-in strategy must be a priority.

Bechtel states that its retrofit design objective is to minimize outage time:[20]

> For all of the closed-cycle cooling technologies, the construction approach is to complete as much of the scope prior to the plant outages as possible. This will minimize the outage time for the remaining work related to CW pipe removal and installation tie-ins and hookups.
>
> To minimize the impact to plant operations as much as possible, all possible pre-outage work will be completed prior to starting the outage.

Bechtel then contradicts its stated objective by choosing a circulating water duct construction approach that would shut down DCPP for 2.3 years:[21]

> The excavation west of the turbine building inside the protected area for the new CWS concrete ducts would be completed during a dual unit outage. This excavation would consist of another 275,000 cubic yards of material that would swell to approximately 322,000 cubic yards and would also be hauled to the spoils area and processed for reuse.
>
> 52,000 cubic yards of concrete ductwork west of the turbine buildings inside the protected area would be placed during a dual unit outage.

Bechtel's inefficient approach to circulating water duct construction and tie-in west of the DCPP turbine building is another reason why this project should be put out to competitive bid. Bechtel has provided no compelling reason why circulating water duct tie-in activities that take weeks to complete at other power plants facing similar circulating water duct design challenges will take years to complete at DCPP. It is the opinion of Powers Engineering that cost penalty implications of Bechtel's inefficient approach to circulating water duct construction and tie-in west of the DCPP turbine building would not survive a competitive bidding process.

c. Composite fiber-reinforced polymer (CFRP) coatings can be applied over the interior surface of the existing cooling water ducts to increase the pressure rating as needed

Composite fiber-reinforced polymer (CFRP) coatings can be applied to the interior surfaces of the cooling water ducts to increase the pressure rating of these ducts as shown in Figure 3. CFRP

[19] Bechtel, Final Addendum, Sept. 17, 2014, p. 50. 1,155 MW × 24 hr × $46.76 MWh × 2 units = $2,592,374/day.
[20] Bechtel, Final Addendum, September 17, 2014, p. 32, p. 35.
[21] Ibid, pp. 28-29.

coatings have been used to upgrade power plant circulating water piping.[22] The estimated cost to increase the pressure rating of the cooling water ducts under the DCPP turbine building to 50 psig (115 feet) would be approximately $55 to $60 per square foot of interior surface area using two layers of wet layup CFRP.[23] This is equivalent to approximately $2,800 per liner feet of cooling water duct.[24] The amount of time necessary to coat 1,000 linear feet of Unit 1 and 2 circulating water duct at DCPP would be approximately four weeks or less.[25,26]

Figure 3. Application of CFRP to interior walls of existing 10-foot diameter circulating water pipe at San Juan Generating Station[27]

d. Pressure relief valves can be installed in cold water return piping to reduce pressure

Plunger valves, a form of continuous pressure relief valve, can also be installed in the cooling tower cold water return piping to reduce water pressure to a level below the current pressure rating of the existing surface condensers and associated circulating water ducts. See Figure 4. Four 78-inch diameter plunger valves would be sufficient for continuous pressure control of a 600,000 gpm cooling tower circulating water flow rate.[28,29] A standpipe would be located between the plunger valves and the surface condensers to assure that pressure rating of the

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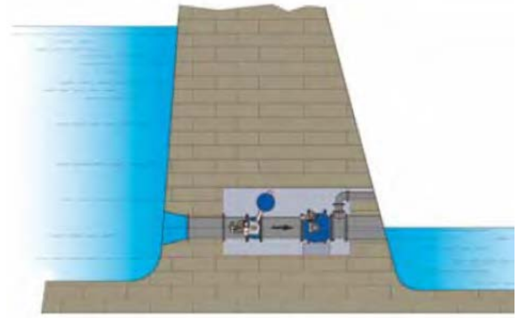
[22] Concrete Repair Bulletin, *Restoration of Large Diameter Prestressed Concrete Cylinder Pipelines*, November/December 2008, pp. 45-47.
[23] Mo Eshani – president, QuakeWrap, Inc., telephone conversation with Bill Powers, Powers Engineering, March 31, 2014.
[24] Enercon Services, Inc., *Diablo Canyon Power Plant Cooling Tower Feasibility Study*, March 2009, , p. 23. Cooling water ducts are square with interior dimensions of 11.75 feet by 11.75 feet. Interior circumference is 47 feet. At a cost of $60 per square foot, the cost of CRFP reinforcement per linear foot of cooling water duct = 47 feet × $60 per square foot = $2,820/linear foot.
[25] Concrete Repair Bulletin, *Restoration of Large Diameter Pre-stressed Concrete Cylinder Pipelines*, November/December 2008, pp. 45-47.
[26] Mo Eshani – president, QuakeWrap, Inc., e-mail to Bill Powers, Powers Engineering, December 2, 2014.
[27] Concrete Repair Bulletin, *Restoration of Large Diameter Pre-stressed Concrete Cylinder Pipelines*, November/December 2008, pp. 45-47.
[28] K. Magle – VAG, design specification for 78-inch VAG plunger valve, 80 feet pressure reduction, maximum flow 157,000 gpm, prepared for B. Powers/Powers Engineering, August 30, 2012.
[29] Powers Engineering recommends the Unit 1 and 2 cooling towers operate with a circulating cooling tower flowrate of 600,000 gpm. See: http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/docs/powers_040814.pdf.

surface condensers and circulating water ducts would not be exceeded in the event of a plunger valve failure.[30]

Figure 4. Plunger valves in cooling tower return piping for continuous pressure reduction[31]



3a. Bechtel erred on the width of the ClearSky™ cooling tower cell, Powers Engineering erred on the length of the ClearSky™ cell

SPX Cooling Technologies, Inc. (SPX), the manufacturer of the ClearSky™ cooling tower technology, provided Bechtel with a specification for 44- and 34-cell back-to-back ClearSky™ cooling towers using cooling tower cells with a width of 54 feet and length of 56 feet. Bechtel misidentifies the width of the cooling tower cells as 60 feet, not the correct 54 feet, in the September 17, 2014 Final Addendum.[32] This error increases the apparent size of the cooling tower(s) and increases the complexity of fitting the cooling tower(s) in available parking lots at DCPP.

The SPX model number for the ClearSky™ design provided by SPX to Bechtel is F497D.[33] The F4 designation signifies the type of cooling tower design used. The "D" signifies the ClearSky™ cooling cell design. The "9" signifies the width of the cooling tower in 6-foot increments. Therefore the width of the cooling tower cell in the SPX specification provided to Bechtel is 9 × 6 feet = 54 feet. The "7" signifies the length of the cooling tower cell in 8-foot increments. Therefore the length of the cooling tower cell in the SPX specification provided to Bechtel is 56 feet. The F497D designation, specific to the ClearSky™ cooling cell design, means each cell measures 54 feet widthby 56 feet length.

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[30] Power Engineering, *Converting Once-Through Cooling to Closed-Loop*, October 22, 2013, pp. 5-6.

[31] VAG brochure, *VAG RIKO®-Plunger Valve: The new generation regulating - closing – safeguarding*, Edition 3, June 2011.

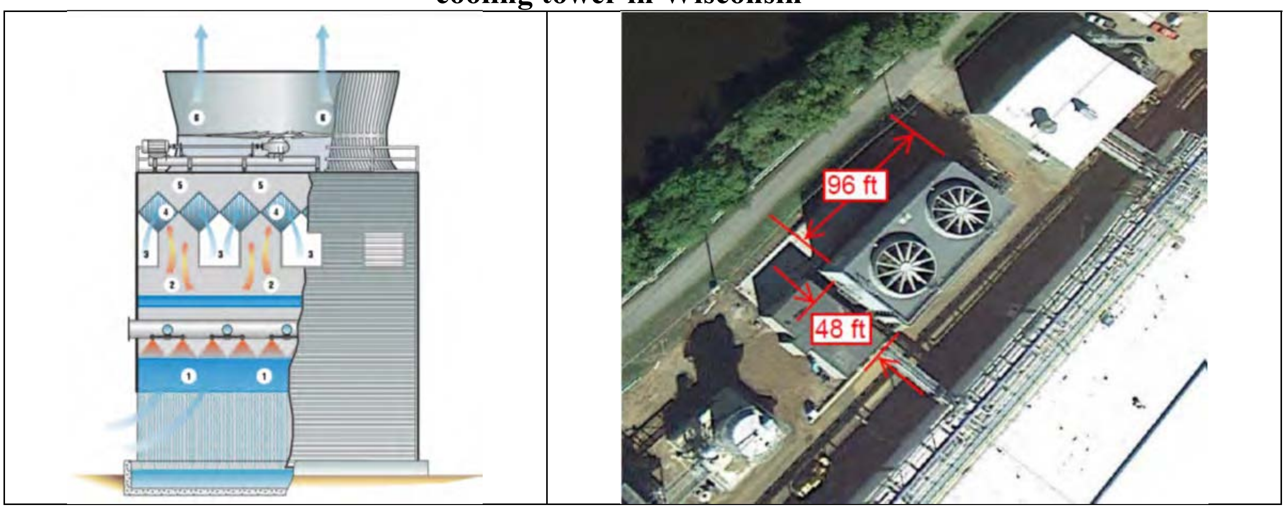
[32] Bechtel Final Addendum, September 17, 2014, p. 12.

[33] Doug Dismukes – Bechtel, e-mail to Bill Powers, Powers Engineering, and Jonathan Bishop, SWRCB, 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). "F4" translates to F400 series cooling tower cell, "9" is cell width of 9 × 6 feet = 54 feet, "7" is cell length of 7 × 8 feet = 56 feet, "D" is ClearSky. "6.6" is the depth of the fill material in feet. "B" signifies back-to-back cooling cells.

The first commercial ClearSky™ cooling tower became operational in November 2013.[35] Prior to the commercialization of the ClearSky™ cooling tower cell technology, SPX model numbers exclusively used 6-foot increments for length and width.[36] As a result, a non-ClearSky™ SPX cooling tower with an F497 model number would refer to a cooling tower with cooling cell dimensions of 9 × 6 feet = 54 feet width by 7 × 6 feet = 42 feet length. Powers Engineering incorrectly identified the length of the ClearSky™ cooling cell in the SPX specification provided to Bechtel as 7 × 6 feet = 42 feet. The revised ClearSky™ length dimension is in multiples of 8 feet and the correct cell length in the SPX ClearSky™ specification is 7 × 8 feet = 56 feet.

Cooling tower cell dimensions can vary depending on the characteristics of a specific site. The first commercial ClearSky™ cooling tower is a 2-cell F486D at a 50 MW biomass cogeneration plant in Wisconsin.[37,38] Cooling cell dimensions are 8 × 6 feet = 48 feet width and 6 × 8 feet = 48 feet length. A cross-section of the ClearSky™ cooling tower cell and an aerial photo of the first 2-cell commercial ClearSky™ cooling tower in Wisconsin is shown in Figure 5.

Figure 5. Cross-section of ClearSky™ cell and photo of first commercial ClearSky™ cooling tower in Wisconsin[39,40]



The second commercial ClearSky™ cooling tower is a 12-cell F4117D under construction at the Newark Energy Center.[41] Cooling cell dimensions are 11 × 6 feet = 66 feet width and 7 × 8 feet

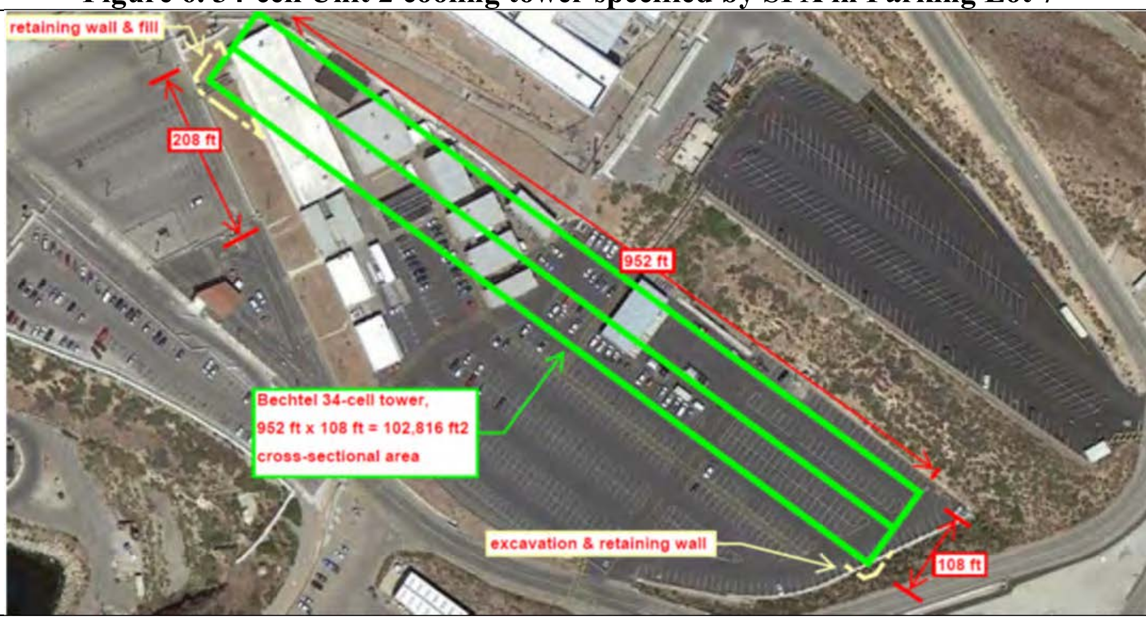
[35] Wood Bioenergy News, *We Energies Begins Commercial Operation*, February 2014. See: http://www.woodbioenergymagazine.com/magazine/2014/0214/in-the-news.php.
[36] SPX Cooling Technologies, Inc., *F400 class counterflow cooling tower – bulletin*, 2013, p. 3. "Design flexibility - F400 towers are available in numerous basic cell sizes. Length and width may vary in 6'-0" increments. Tower height, fill height, and fill density are also variable."
[37] Terry Wiegert – Domtar Rothschild WI biomass cogeneration plant, telephone conversation with Bill Powers, Powers Engineering, November 24, 2014.
[38] Andjelko Piskuric -Global Product Manager SPX Cooling Technologies Inc,, telephone conversation with Bill Powers, Powers Engineering, November 24, 2014.
[39] P. Lindahl, K. Mortensen – SPX Cooling Technologies, *Plume Abatement – The Next Generation*, Cooling Technologies Institute paper TP10-09, February 2010, Figure 10, p. 5.
[40] Google Earth photo, tags added by B. Powers.
[41] Ibid.

= 56 feet length. The 705 MW Newark Energy Center is expected to be operational by May 2015.[42]

3b. 34-cell ClearSky™ cooling tower for Unit 2 fits on existing Parking Lot 7 site

The 34-cell cooling tower specified by SPX for Unit 2 is shown in Figure 6 in the Parking Lot 7 location at an elevation of 123 feet.[43] The tower is long and narrow, though it does fit on the parking lot site.[44]

Figure 6. 34-cell Unit 2 cooling tower specified by SPX in Parking Lot 7[45]



Most of the existing structures in Parking Lot 7 would have to be removed or relocated to accommodate the installation of the cooling tower. These structures were identified as "temporary buildings" in the 2008 TetraTech cooling tower retrofit evaluation for DCPP.[46] The specific function(s) of these structures are identified in June 2009 Enercon and September 2014 Bechtel cooling tower retrofit reports for DCPP. The identification numbers of structures in Parking Lot 7 are shown in Figure 7. These structures are listed in Table 1 by identification number and function.

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[42] Platts McGraw-Hill Financial, *Hess sells remaining interest in N.J. gas-fired plant to Energy Investors Funds*, June 20, 2014.
[43] Doug Dismukes – Bechtel e-mail to Bill Powers, January 17, 2014, attached drawing of preliminary 44-cell cooling tower layout. Elevations of each parking lot are hand-drawn on the Bechtel drawing.
[44] As shown in Figure 6, some fill would be necessary, on the order of 3,000 yd^3, at the northwest corner of the cooling tower for it to fit in the Parking Lot 7 site.
[45] Google Earth photo, tags added by B. Powers.
[46] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis; Chapter C – Diablo Canyon Power Plant*, February 2008, p. C-13.

Figure 7. Identification numbers of structures in Parking Lot 7[47]

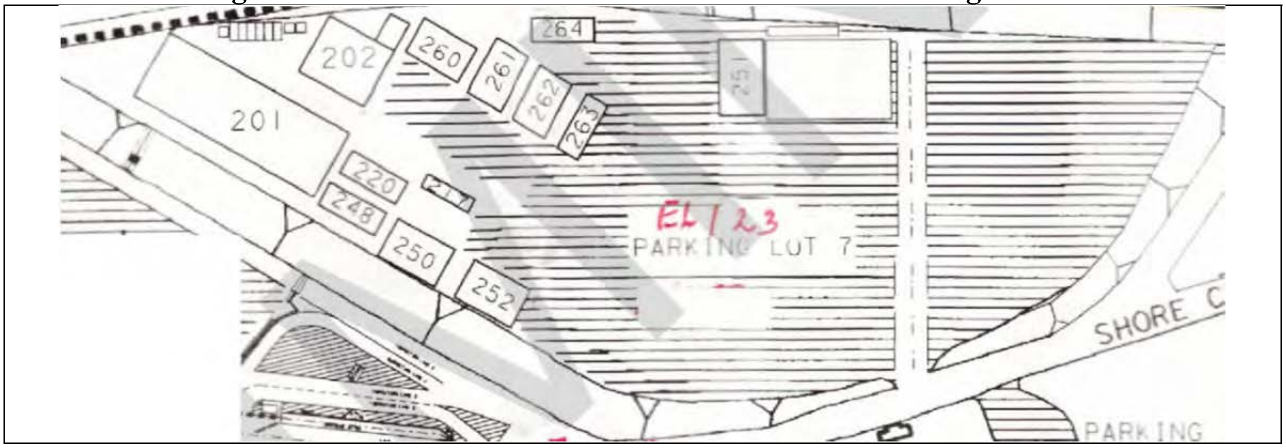

Table 1. Structures in Parking Lot 7 that would be removed to accommodate Unit 2 cooling tower[48,49]

Building number	Building function(s)
201	design engineering offices
202	design engineering offices
217	restrooms
220	design engineering offices
248	outage human resources office
250	project offices
251	fire house
252	project offices
260	security/records storage
261	records storage/offices
262	telecommunications/project offices
263	training facility
264	building services

Shorter and wider cooling tower designs are better adapted to the available parking lot space at DCPP. Cooling towers of similar cross-sectional area, though with different cell width by length dimensions, will yield similar performance when other substantive variables, such as packing type and depth, circulating water flowrate, and fan horsepower, are held constant.[50,51]

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[47] Doug Dismukes – Bechtel, e-mail to Bill Powers, January 17, 2014, attached drawing of preliminary 44-cell cooling tower layout.
[48] Enercon Services, Inc., *Diablo Canyon Power Plant Cooling Tower Feasibility Study*, March 2009, pp. 15-16.
[49] Bechtel also provides a partial list of buildings/function located in Parking Lot 7. See Bechtel Final Addendum, September 17, 2014, p. 18. However, because this list is incomplete, Powers Engineering relies on the list of buildings/function in the March 2009 Enercon cooling tower feasibility study.
[50] Levi Sallee - Technical Sales Engineer, GEA Heat Exchangers, Inc., Cooling Tower Solutions Division, e-mail to Bill Powers, Powers Engineering, September 10, 2013.
[51] Andjelko Piskuric - Global Product Manager SPX Cooling Technologies Inc,, telephone call with Bill Powers, Powers Engineering, November 24, 2014.

Adjustments to the major variables, such as increasing packing depth or increasing fan horsepower, can also be made to incrementally improve the performance of a given cooling tower design.[52]

Bechtel incorrectly identified the width of the cooling cell in the SPX specification as 60 feet. However, if 60 feet is assumed as the cooling cell width that will be used in the ClearSky™ cooling tower, then the length of the cell can be reduced to 48 feet while maintaining similar cross-sectional area and performance compared to the base case 34-cell cooling tower specified by SPX with 54 feet by 56 feet cells.[53] This 34-cell cooling tower, with a width of 120 feet and a length of 816 feet, is shown in Figure 8.

Figure 8. 34-cell Unit 2 cooling tower using cell width of 60 feet per Bechtel and 48 feet length to achieve performance similar to SPX basecase specification

The Newark Energy Center 12-cell ClearSky™ cooling tower uses 66 feet by 56 feet cells. A 28-cell ClearSky™ back-to-back cooling tower using 66 feet by 56 feet cells would have about the same cross-sectional area as the basecase 34-cell ClearSky™ cooling tower shown in Figure 6, and would be expected to achieve similar performance. The 28-cell cooling tower is shown in Figure 9.

[52] Joe Padilla - Western Regional Manager, Power/Industrial Products, Marley Cooling Technologies, e-mail to Bill Powers, Powers Engineering, November 10, 2005.
[53] Andjelko Piskuric - Global Product Manager SPX Cooling Technologies Inc., telephone conversation with Bill Powers, Powers Engineering, November 24, 2014.

Figure 9. 28-cell Unit 2 cooling tower using cell dimensions of 66 feet width by 48 feet length to achieve performance similar to SPX basecase specification

A 15-foot wide buffer around the ClearSky™ cooling tower(s)s is sufficient to provide maintenance access for vehicles. 15- to 20-feet is the approximate width of the access road on one side of the 40-cell back-to-back Plant Yates cooling tower (GA) shown in Figure 10.

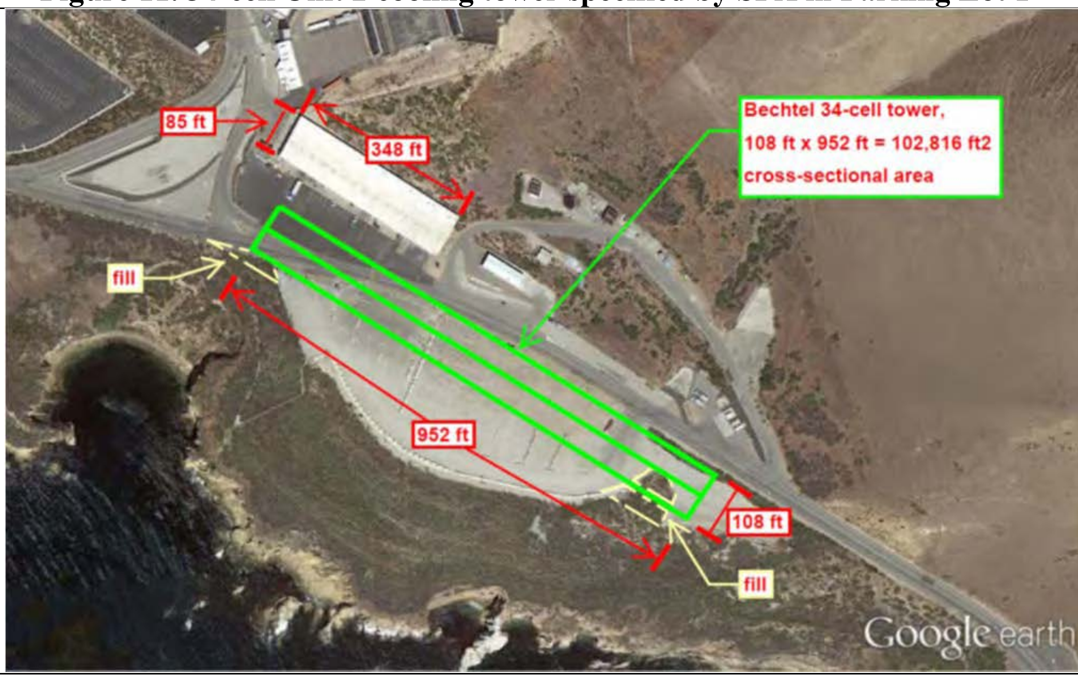
Figure 10. Plant Yates 40-cell back-to-back cooling tower with 15- to 20-foot wide access road on one side[54]

[54] Google Earth photo with lines and tag added by B. Powers.

3c. 34-cell ClearSky™ cooling tower for Unit 1 fits on existing parking lot/road site

The 34-cell cooling tower specified by SPX for Unit 2 is shown in Figure 11 in the Parking Lot 1 location at an elevation of 131 feet.[55] The tower as specified by SPX would extend into the existing paved roadway and truck turnaround area at the adjacent to the northern end of Parking Lot 1.

Figure 11. 34-cell Unit 2 cooling tower specified by SPX in Parking Lot 1[56]



Bechtel incorrectly identified the width of the cooling cell in the SPX specification as 60 feet. However, if 60 feet is assumed as the cooling cell width that will be used in the ClearSky™ cooling tower, then the length of the cell can be reduced to 48 feet while maintaining similar cross-sectional area and performance compared to the base case 34-cell cooling tower specified by SPX with 54 feet by 56 feet cells.[57] This 34-cell cooling tower, with a width of 120 feet and a length of 816 feet, is shown in Figure 12.

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[55] Doug Dismukes – Bechtel e-mail to Bill Powers, January 17, 2014, attached drawing of preliminary 44-cell cooling tower layout. Elevations of each parking lot are hand-drawn on the Bechtel drawing.
[56] Google Earth photo, tags added by B. Powers.
[57] Andjelko Piskuric – Global Product Manager SPX Cooling Technologies Inc., telephone conversation with Bill Powers, Powers Engineering, November 24, 2014.

Figure 12. 34-cell Unit 1 cooling tower using cell width of 60 feet per Bechtel and 48 feet length to achieve performance similar to SPX basecase specification

The Newark Energy Center 12-cell ClearSky™ cooling tower uses 66 feet by 56 feet cells. A 28-cell ClearSky™ back-to-back cooling tower using 66 feet by 56 feet cells would have about the same cross-sectional area as the basecase 34-cell ClearSky™ cooling tower shown in Figure 11, and would be expected to achieve similar performance. The 28-cell cooling tower is shown in Figure 13.

Figure 13. 28-cell Unit 2 cooling tower using cell dimensions of 66 feet width by 48 feet length to achieve performance similar to SPX basecase specification

4. Palisades Nuclear Plant operated as a once-through cooled unit for a year-and-a-half before conversion to closed cycle cooling

Bechtel is wrong to assert that the Palisades Nuclear Plant did not operate initially as a once-through cooled power plant. Entergy's Palisades Nuclear Power Plant began commercial operation on December 31, 1971.[58] Palisades operated as a once-through cooled nuclear plant in 1972 and 1973 before conversion to closed-cycle cooling during an outage from August 1973 to April 1975.[59] The electricity production of Palisades Nuclear in its first ten years of commercial operation is shown in Table 2. The electricity production rate in 1973, when Palisades operated with a once-through cooling system, was comparable to the electricity production rates in 1975, 1978, and 1980 after Palisades converted to a closed-cycle cooling system.

Table 2. Palisades Nuclear Electricity Production – First Ten Years of Operation[60]

Year	Electricity Production (MWh)	Cooling System Type
1972	1,899,100	once through
1973	2,411,300	once through
1974	93,300	unknown
1975	2,427,800	closed cycle
1976	2,846,900	closed cycle
1977	5,084,600	closed cycle
1978	2,624,200	closed cycle
1979	3,433,400	closed cycle
1980	2,379,100	closed cycle
1981	3,462,700	closed cycle

The NRC reported the following causes for the Palisades August 1973 to April 1975 outage:[61]

> An outage was initially estimated for 3 months to repair [the plant's steam generators]. Internal reactor problems and a waste gas release investigation prolonged the outage into 1974. The new cooling towers were completed and placed in operation and the turbine-generator was overhauled.... [Consumers Power] filed a suit against several vendors for startup problems with the condenser, [steam generators], and core internals. Turbine repairs and condenser-retubing extended the outage even further.

According to an article in the October 1974 issue of Nuclear News, Consumers Power had said that the outage was "due principally to steam generator corrosion and damage caused by vibration of the reactor core internals, as well as defective main condenser design and tubing." As a result, Consumers Power sued Bechtel and four other companies who helped to build the

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[58] Entergy Palisades Power Plant webpage: http://www.entergy-nuclear.com/plant_information/palisades.aspx.

[59] **Staff Exhibit 21,** U.S. EPA, 2002 Phase II TDD Chapter 4, *Cooling System Conversions at Existing Facilities*, p. 4-4. The Palisades plant constructed the main portions of the tower system in 1972 and 1973, while the plant operated in once-through mode."

[60] International Atomic Energy Agency website, Power Reactor Information System (PRIS), Palisades Nuclear: http://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=616.

[61] NRC, *Nuclear Power Plant Operating Experience Summary*, NUREG/CR-6577, p. 243.

Palisades nuclear plant because "equipment supplied [in 1966 and 1967] was defective" and that defective equipment had not been promptly and adequately repaired.[62]

5. The quantity of salt drift from the Palo Verde Nuclear Generating Station cooling towers is about the same as salt drift projected for seawater cooling towers at DCPP

Bechtel is wrong to assert that the salt drift rate at Palo Verde is not comparable to the salt drift projected for seawater cooling towers at DCPP. Palo Verde Nuclear Generating Station is the largest nuclear plant in the U.S. It is located about 40 miles west of Phoenix, Arizona. It began operation at about the same time as DCPP, in the mid-1980s.[63] Palo Verde employs round mechanical draft cooling towers in a closed cycle cooling system. Palo Verde utilizes treated wastewater from nearby Phoenix as make-up water supply for the cooling towers. The total dissolved solids content, also known as "salt" content, in the make-up water is concentrated by a factor of 24 to 30 in the circulating cooling water. As a result of this salt concentration, the salt content in the circulating water in the Palo Verde cooling towers is about 70 percent that of seawater at 24,000 parts per million.[64]

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[65] and 1,736,600 gpm at DCPP, are about the same. The estimated drift rate at Palo Verde is 0.001 percent.[66] The SPX guarantee for the ClearSky™ towers proposed for DCPP 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.

Salt deposition from cooling tower drift has been successfully managed at Palo Verde during nearly three decades of operation. Palo Verde Nuclear is shown in Figure 14.

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[62] D. Schlissel – Synapse Energy Economics, *letter report regarding closed-cycle cooling conversion outage duration re EPA's NODA for Phase II Cooling Water Intake Regulations*, submitted to Riverkeeper, Inc., May 30, 2003, p. 2.

[63] 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.

[64] 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."

[65] Ibid, pp. 20-21.

[66] Diablo Canyon Independent Safety Committee, *Final 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 17, 2014, p. 13. See: http://www.dcisc.org/2014-10-17-final-assessment.pdf.

Figure 14. Palo Verde Nuclear Plant with Round Mechanical Draft Cooling Towers[67]

The three DCPP Unit 2 transformer reliability incidents related to salt deposition that are documented in the Oct. 17, 2014 Diablo Canyon Independent Safety Committee final safety evaluation occurred during a light rain (2 incidents) and hot washing overspray (1 incident).[68] Salts deposited on the Unit 2 transformers, which the DCISC attributes to salt spray generated by the once-through cooling discharge structure, combined with flowing water in the form of rain or hot washing overspray, were a substantive contributor to the arcing. The salts are deposited on the transformers and associated insulators through airborne deposition and water flowing over the transformer/insulator creates a saline electrolyte that induces arcing. It is not clear from these DCISC accounts how relative humidity at the site affects the salt deposition rate, or whether it makes a substantial difference if the ambient air is humid (DCPP) or dry (Palo Verde).

[67] [67] J. Maulbetsch, M. DiFilippo, *Performance, Cost, and Environmental Effects of Saltwater Cooling Towers – PIER Final Consultant Report*, prepared for California Energy Commission, January 2010, Appendix C, Section C.6: Palo Verde Nuclear Generating Station, p. APC-39.

[68] Diablo Canyon Independent Safety Committee, *Final 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 17, 2014, pp. 12-13.

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, Figure 2-6: Pressure-Time Profile for the Diablo Canyon Power Plant Cooling Water System, p. 2-10.

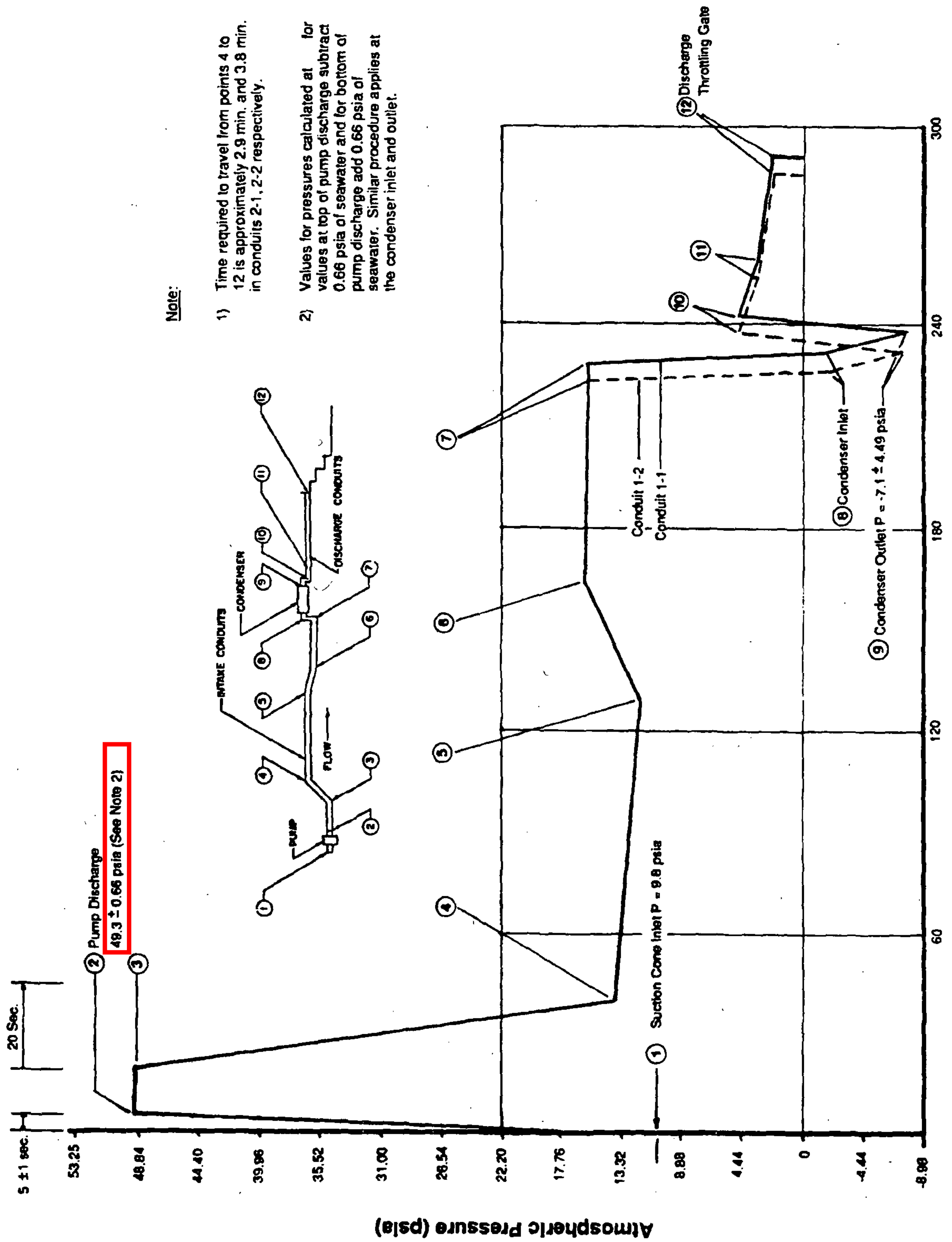


Figure 2-6

Pressure-Time Profile for the Diablo Canyon Power Plant Cooling Water System (Source: Wilson 1977)

Figure B-1. Existing DCPP OTC circulating water system[1]

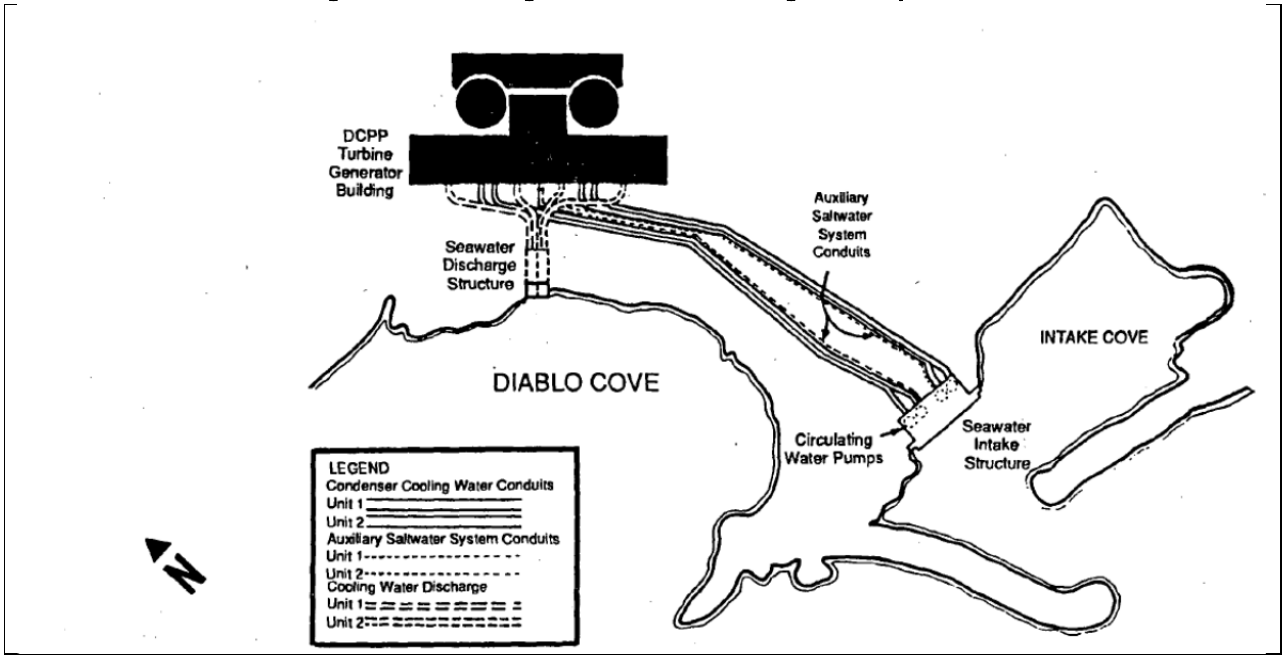
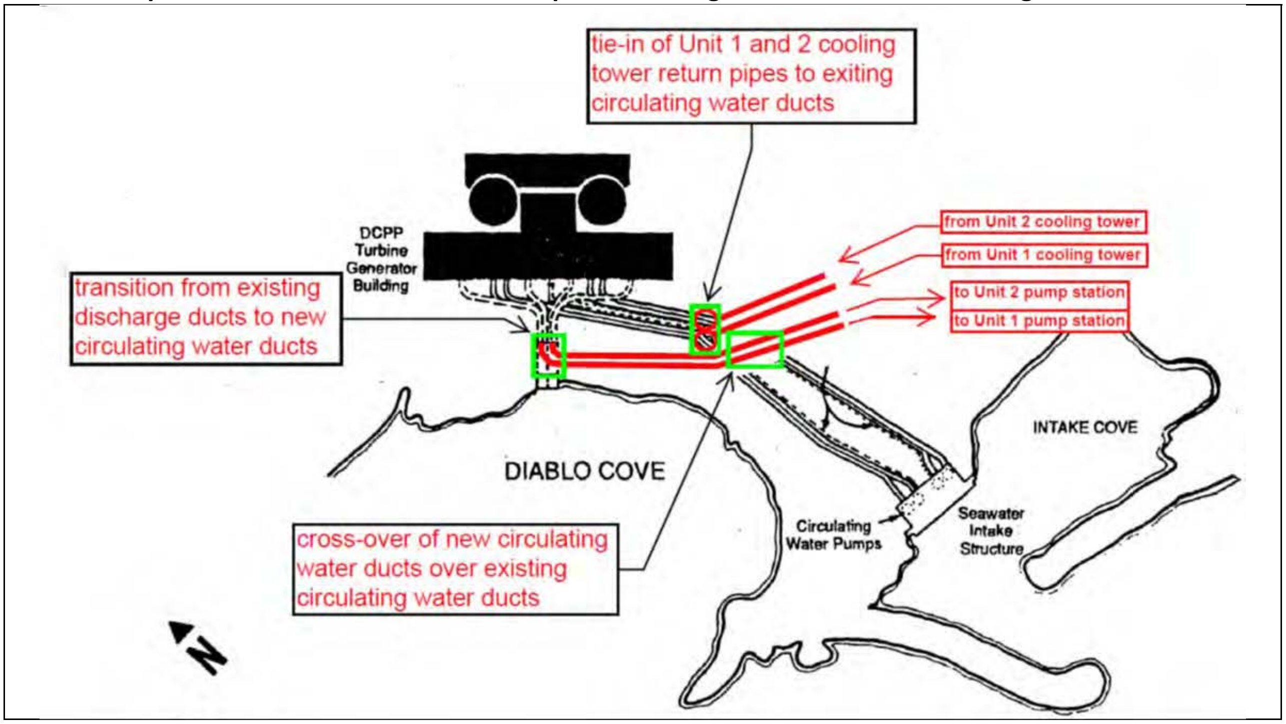


Figure B-2. Three cooling tower retrofit construction activities that require a DCPP plant outage to complete – affected activities that require an outage occur within the three green frames[2]



[1] 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, Figure 2-2: General Configuration of the Diablo Canyon Power Plant Cooling Water System, p. 2-4.
[2] Ibid. Lines and tags added by B. Powers.

Figure B-3. Existing OTC circulating water system in front of and under the DCPP turbine building[3]

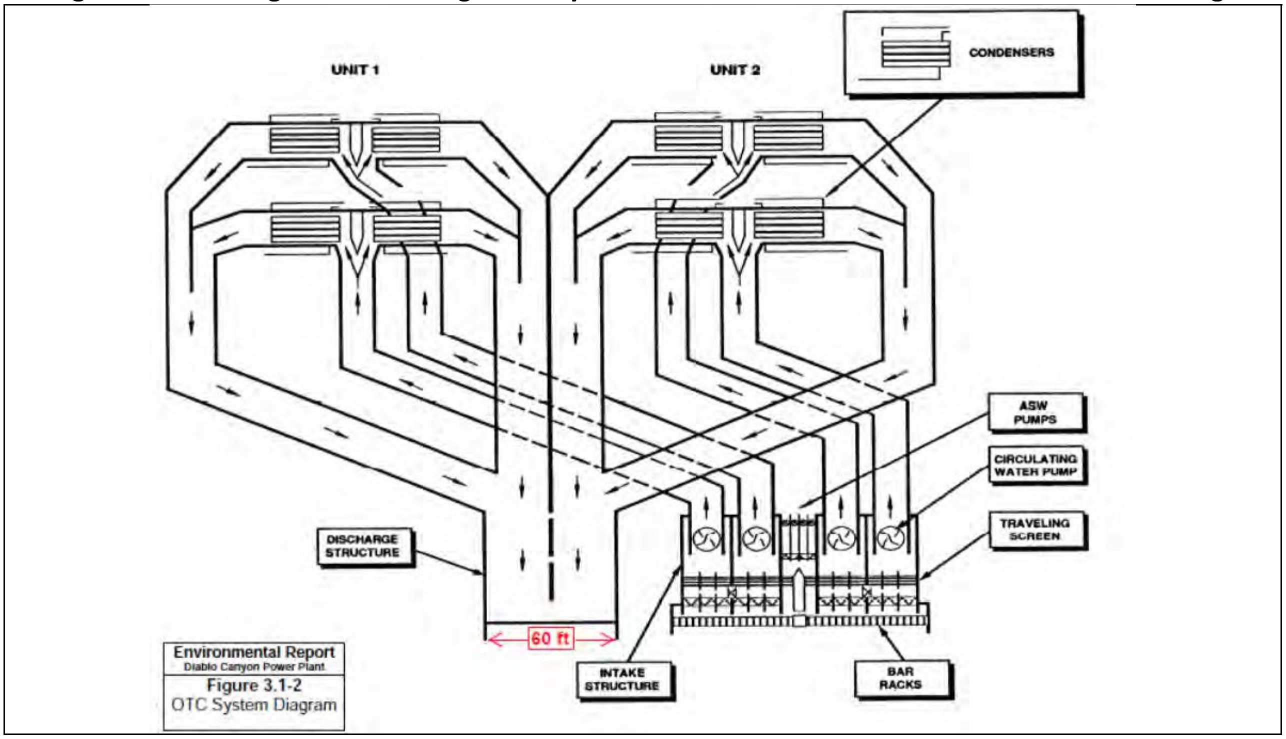
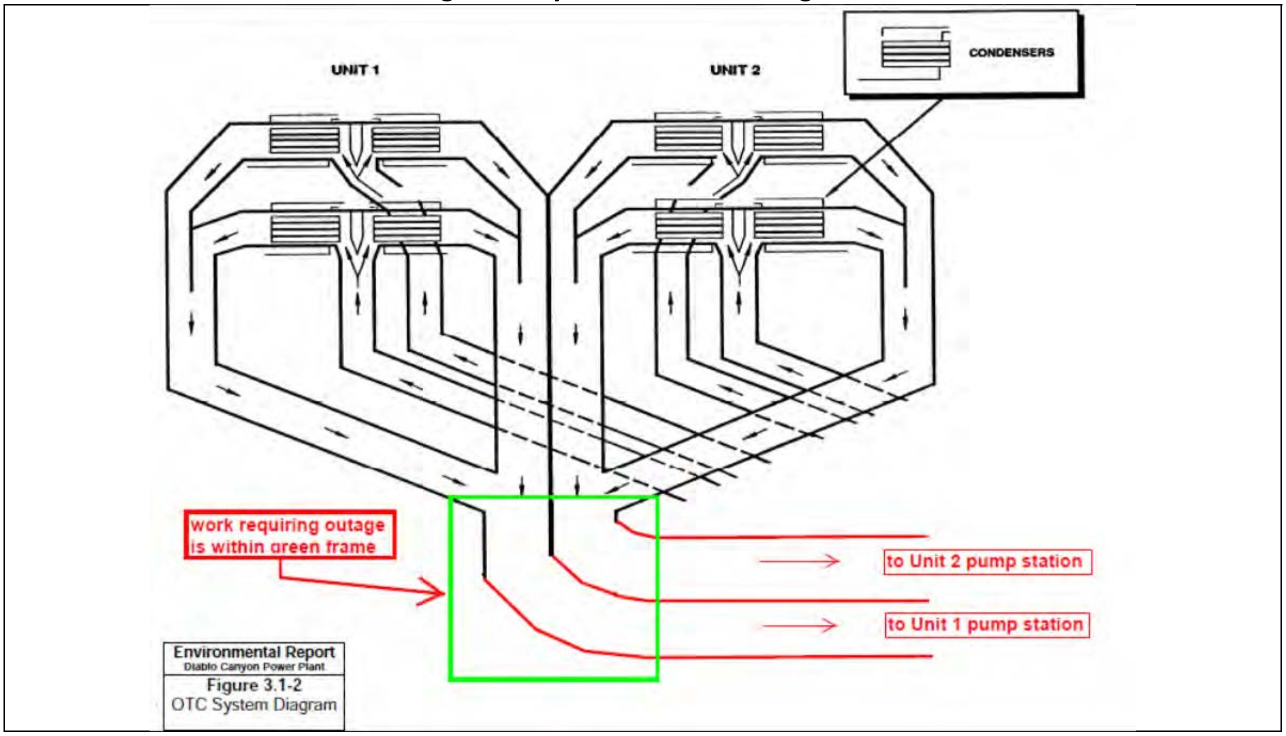


Figure B-4. Area of work at DCPP turbine building requiring outage to convert to closed-cycle circulating water system – area within green frame[4]



[3] PG&E, *DCPP License Renewal Application – Environmental Report: Operating License Renewal Stage, Appendix E*, November 23, 2009, Figure 3.1-2. Tag added by B. Powers.
[4] Ibid. lines and tags added by B. Powers.

EXHIBIT B

March 17, 2023

Chair Joaquin Esquivel and Board Members
State Water Resources Control Board
1001 I Street
Sacramento, CA 95814

RE: Comment Letter – OTC Policy Amendment

Sent via electronic submission to: commentletters@waterboards.ca.gov

Dear Chair Esquivel and Members of the Board**:**

INTRODUCTION

As provided by the State Water Resources Control Board's (WRCB's) Notice of Document Availability, Opportunity for Public Comment, and Public Hearing (Jan. 4, 2023) (hereinafter "Notice"), San Luis Obispo Mothers for Peace, Environmental Working Group, and Friends of the Earth (collectively "Commenters") hereby comment on the Draft Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (hereinafter "Draft Policy Amendment") and the Draft Staff Report submitted in support of the Draft Policy Amendment).[1]

These comments focus on the proposed changes to the deadlines for compliance by the Pacific Gas and Electric Co. (PG&E) with Section 316(b) of the federal Clean Water Act (CWA) for the Diablo Canyon nuclear power plant ("Diablo Canyon"). Section 316 of the CWA requires that "the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts."[2]

As stated in the Notice, the Draft Policy Amendment would make:

> a change without regulatory effect to revise the compliance date for Diablo Canyon Nuclear Power Plant (Diablo Canyon) Units 1 and 2 to October 31, 2030 to comport with the extension provided by Senate Bill 846.[3]

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[1] The WRCB has posted the Notice at https://www.waterboards.ca.gov/public_notices/comments/water_quality_enforcement/notice_wqenforcement_021023.pdf. The Draft Policy Amendment and the Draft Staff Report are posted at https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.html.

[2] 33 U.S.C. § 1326. *See also* 2010 Statewide Water Quality Control Policy at 1; Final Substitute Environmental Document, Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling at 1-2 (May 4, 2010) ("2010 Final Substitute Environmental Document") (https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_sed2010.pdf).

[3] Notice at 1, 3; Draft Policy Amendment at 18; Draft Staff Report at 12.

The Draft Policy Amendment would extend by five to six years the current compliance dates of November 2, 2024 for Unit 1 and August 28, 2025 for Unit 2.[4]

Commenters respectfully submit that the proposed change to the deadlines for complying with Section 316(b) are unlawful because the WRCB has not complied with its own legal processes for establishing or changing CWA compliance deadlines, as set forth in the 2010 Policy.

Moreover, contrary to the WRCB's assertion, a recently passed State law, S.B. 846, purportedly setting a new compliance deadline for Diablo Canyon, has no lawful effect on the 2024 and 2025 deadlines established in the 2010 Policy and 2021 Policy Amendment. The U.S. Environmental Protection Agency (EPA) has delegated the authority to WRCB to carry out the requirements of the CWA.[5] The EPA gave no such authority to the California Legislature. Therefore, statutory compliance deadlines may only be altered by the WRCB under the authority delegated to it by the CWA and the Memorandum of Agreement between the State and the U.S. Environmental Protection Agency (EPA), for implementation of the CWA.

Accordingly, the WRCB must not interpret S.B. 846 as extending Diablo Canyon's compliance deadline with the OTC Policy because to do so would run afoul of WRCB's delegated authority by the USEPA; the existing compliance deadlines of November 2, 2024 (Unit 1) and August 28, 2025 (Unit 2) for PG&E to come into compliance with CWA Section 316(b) must be maintained. And because the WRCB has determined that cooling towers constitute the "best technology available" (BTA) for achieving compliance with Section 316(b), PG&E must be required to install cooling towers by those dates.[6]

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[4] Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling at 15 (May 4, 2010) (hereinafter "2010 Policy"). The WRCB originally established a compliance deadline of December 31, 2024 for both Units 1 and 2. In 2021, upon receiving notification by PG&E that it intended to retire the Diablo Canyon reactors on their operating license expiration dates of November 2, 2024 for Unit 1 and August 26, 2025 for Unit 2, the WRCB changed the previous compliance date to conform to the reactors' retirement dates. Final Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Oct. 19, 2021) ("2021 Policy Amendment") (https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2021/final_amdmt.pdf).

[5] *See* CWA Section 402, 33 U.S.C. § 1342. *See also* NPDES Memorandum of Agreement Between the U.S. Environmental Protection Agency and the California State Water Resources Control Board (Sept. 22, 1989) (https://www.epa.gov/sites/default/files/2013-08/documents/ca-moa-npdes_0.pdf.)

[6] *See* 2010 Policy at 4. *See also* Final Substitute Environmental Document at 58-66. The WRCB must disregard the finding contained in § 5 of S.B. 846 that cooling towers are not "feasible," because the California Legislature has no delegated statutory or regulatory authority to make such a finding, nor is there any substantial evidence supporting such a finding.

LEGAL AND FACTUAL BACKGROUND

The WRCB's authority to issue and amend its 2010 Water Quality Control Policy arises from the CWA, passed by Congress in 1972 to regulate discharges of pollutants into the waters of the United States. The CWA is administered by the EPA through the issuance of National Pollutant Discharge Elimination System (NPDES) permits.[7] Under Section 402(b) of the CWA, EPA has delegated NPDES permitting authority to the California WRCB through the 1989 MOA.[8] As summarized in the 2010 Final Substitute Environmental Document:

> In 1972, the California Legislature amended Porter-Cologne to provide the state the necessary authority to implement an NPDES permit program in lieu of a USEPA-administered program under the CWA. To ensure consistency with CWA requirements, Porter-Cologne requires that the Water Boards issue and administer NPDES permits such that all applicable CWA requirements are met. The State Water Board is designated as the state water pollution control agency under the CWA and is authorized to exercise any powers accordingly delegated to the State.[9]

NPDES permits issued by the WRCB "must comply with all minimum federal clean water requirements" and "are issued under an EPA-approved state water quality control program."[10] In administering this EPA-approved program, the WRCB and all other State agencies must acknowledge and apply "the supremacy of federal law."[11]

In 2010, in an exercise of its delegated authority under the CWA, the WRCB established a Statewide Water Quality Control Policy.[12] Based on an exhaustive environmental study as documented in the Final Substitute Environmental Document, the WRCB concluded that for

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[7] 33 U.S.C. § 1251, *et seq.* The CWA amended and significantly expanded the 1948 Federal Water Pollution Control Act.

[8] *See* note 5 above. The MOA delegates EPA's authority to regulate water quality to the WRCB as "the State water pollution control agency for all purposes of the Clean Water Act." *Id.* at 1.

[9] *Id.* at 8 (citing Wat. Code, div. 7, ch. 5.5; Wat. Code, § 13377; California Code of Regulations (CCR), tit. 23, § 2235; CCR § 13160; CCR §§ 13,372, 13377; 40 C.F.R. Parts 122, 123, and 124).

[10] *Voices of the Wetlands v. State Water Resources Control Board,* (2011) 52 Cal. 4th 499 (citing the Porter-Cologne Water Quality Control Act (Porter-Cologne Act; Wat. Code, § 13000 et seq.); Wat. Code §§ 13372, 13377; 33 U.S.C.§ 1342(b); 40 C.F.R. §§ 123.21-123.25 (2011); 39 Fed. Reg. 26061 (Jul. 16, 1974); 54 Fed. Reg. 40664-40665 (Oct. 31, 1989)).

[11] *Id.,* 52 Cal. 4th at 521 ("Under the CWA, a federal statute, any facility that discharges wastewater into a navigable water source . . . must have an unexpired permit, conforming to federal water quality standards, in order to do so.").

[12] 2010 Statewide Water Quality Control Policy, (https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/cwa316may2010/otcpolicy_final050410.pdf.)

existing power plants including Diablo Canyon, closed cycle wet cooling systems (*i.e.,* cooling towers) constituted the Best Technology Available (BTA).[13]

Thus, Diablo Canyon was required to install cooling towers by December 31, 2024, unless it could demonstrate that cooling towers were infeasible or created a conflict with U.S. Nuclear Regulatory Commission (NRC) safety requirements.[14] The Policy also established a staggered compliance schedule for the 19 electric plants covered by the requirement, and set up a Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) composed of representatives from the WRCB, the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), the California Independent System Operator (CAISO) and other interested State agencies to "review implementation plans and schedules" for the purpose of ensuring that "the implementation schedule takes into account local area and grid reliability, including permitting constraints."[15] Finally, the Policy provided for suspension of compliance dates, but only after a determination by CAISO that continued operation "is necessary to maintain the reliability of the electric systems," and only after a public hearing on that determination.[16] Between 2010 and the deadlines for installing cooling towers, the affected companies (including PG&E) were ordered to contribute to a mitigation fund.[17]

In 2016, PG&E entered a settlement agreement with labor unions and environmental groups to close Units 1 and 2 on their operating license termination dates of November 2, 2024 (Unit 1) and August 28, 2025 (Unit 2).[18] The California Public Utilities Ccommission approved the settlement in 2018.[19] PG&E took no steps to install cooling towers, because PG&E officials considered the expense to be unnecessary given PG&E's 2016 agreement with labor unions and environmental groups to close the reactors on their NRC license termination dates.[20]

On September 2, 2022, California Legislature passed into law S.B. 846, directing the California Public Utilities Commission to execute several tasks and consider specific criteria

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[13] *Id.* at 4. *See also* Final Substitute Environmental Document at 58-66.

[14] *Id.* at 4, 8, 15.

[15] *Id.* at 2.

[16] *Id.* at 6.

[17] *Id.* at 7.

[18] *See* Joint Proposal by Pacific Gas and Electric Company, Friends of the Earth, Natural Resources Defense Council, *et al.* to Retire Diablo Canyon Nuclear Power Plant at Expiration of the current Operating Licenses and Replace it With a Portfolio of GHG Free Resources (filed before the CPUC June 20, 2016).

[19] California Public Utilities Commission Decision No. 18-01-022 (January 11, 2018), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M205/K423/205423920.PDF. The CPUC decision was codified in Cal. Senate Bill 1090 (Monning), signed by then-Governor Jerry Brown on September 19, 2018.

[20] *See* https://www.pgecorp.com/corp_responsibility/reports/2021/pl04_water.html.

related to the potential extension of operations at Diablo Canyon, and providing an over $1billion loan to PG&E to support continued operation for at least five years past the previously-approved retirement dates of 2024 for Unit 1 reactor and 2025 for Unit 2 reactor.[21]

In Section 10 of S.B. 846, the state legislature added a new Section 13193.5 to the California Porter-Cologne Act:

> Notwithstanding any provision to the contrary in the State Water Resources Control Board's Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, as referenced in Section 2922 of Title 23 of the California Code of Regulations, the final compliance dates for Diablo Canyon Units 1 and 2 shall be October 31, 2030. Nothing in this section prevents the state board from ordering the operator of the Diablo Canyon powerplant to conduct any other form of mitigation allowed under this chapter.

S.B. 846 includes a finding in Section 25548(b) that "[p]reserving the option of continued operations of the Diablo Canyon powerplant for an additional five years beyond 2025 may be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online."

DISCUSSION[22]

As held by the California Supreme Court in *Voices of the Wetlands v. State Water Resources Control Bd.* (2011) 52 Cal.4th 499, the WRCB's actions must, above all, be consistent with federal law.[23] Here, federal law is established by Section 316 of the CWA; the MOA; and the WRCB's duly-promulgated policy for implementing Section 316, the 2010 Statewide Water Quality Control Policy. Where action by the State legislature is inconsistent with a federal law, here the CWA and its implementing state law and policy, it must be disregarded.

The WRCB Staff Report interprets S.B. 846 in a manner which results in inconsistencies with the CWA and the 2010 Policy in several key respects.

First, by claiming that the Draft Policy Amendment would make "a change without regulatory effect to revise the compliance date for Diablo Canyon Nuclear Power Plant (Diablo Canyon) Units 1 and 2 to October 31, 2030 to comport with the extension provided by Senate Bill 846" the WRCB staff is essentially claiming that the Legislature has usurped WRCB's regulatory authority and has, as such, *per se* extended the compliance dates legislatively. If this is indeed a correct reading of SB 846, which Commenters do not necessarily concede, then this

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[21] S.B. 846 Sections 5 and 9(c)(1)(a); California Public Utilities Commission Order Instituting Rulemaking (R.23-01-007), at pp..1, 2.

[22] Commenters incorporate by reference the California Coastkeeper Alliance's points and authorities on this matter.

[23] *Voices*, supra 52 Cal.4th 499, 509.

provision of SB 846 is *ultra vires* and must be disregarded. (*Estate of O'Dea* (1973) 29 Cal.App.3d 759,771-772 [If a legislative body passes an act which involves a matter upon which the legislature has not been given the power to legislate, the legislative act is necessarily ultra vires and the court in those instances would have not only the power but the duty to so declare].) The Clean Water Act does not permit the state legislature to contravene its terms, nor does the MOA between the federal government and the state. Under the MOA between the State and USEPA, as well as the corresponding provisions of the Porter-Cologne Act, only the WRCB can change the compliance schedule established in the 2010 Statewide Water Quality Control Policy pursuant to the required procedures and processes.

Further, Section 5 of SB 846 makes a bald claim that "it is not practicable for the Diablo Canyon Power Plant to achieve final compliance" with the OTC Policy before 2030. However, the OTC Policy contains specific procedures and requirements that WRCB must follow when appropriately determining BTA feasibility and compliance deadline extensions. The OTC Policy has federal authority, and thus these procedures are akin to federal regulations with the force of federal law, which the state cannot legislatively circumvent. For this reason, notwithstanding the legislature's claim to the contrary, unless WRCB completes its process of determining whether BTA is cost-prohibitive vis-à-vis its environmental benefits, and supports any such determination with substantial evidence, the Draft Policy Amendment may not lawfully be approved by WRCB.[24]

In addition, the State legislature cannot lawfully mandate the WRCB to "continue to impose an interim mitigation fee"[25] on Diablo Canyon until its retirement, in lieu of the procedures and requirements of the OTC Policy; SB 846 cannot lawfully order the Water Board to impose interim mitigation fees on Diablo Canyon as its sole form of compliance with Clean Water Act Section 316(b) for the rest of its operational life, because to do so would be ordering the Water Board to violate the federal court's holding in *Riverkeeper, Inc. et al. v. U.S. Environmental Protection Agency,* (2nd Cir, January 25, 2007) 475 F.3d 83. *("Riverkeeper II").* Thus, because legislation may not be interpreted in a manner that would lead to absurd results (*Torres v. Parkhouse Tire Service, Inc.* (2001) 26 Cal.4th 995, 1003)[26], the WRCB must do more

[24] As California Coastkeeper Alliance notes in its comment letter, during the State Water Board's March 7th OTC Policy Board Workshop, State Water Board staff responded to CCKA's concerns over the lack of BTA for Diablo Canyon. During the workshop, staff responded to Board Member inquiries by stating that it would be infeasible for Diablo to achieve BTA by 2030 and that the 5-year extension would have minimal environmental impacts. First, there is no evidence in the administrative record that it would be infeasible for Diablo to install BTA by 2030. The Nuclear Review Committee determined that Diablo Canyon had several feasible BTA options – the greatest concern was largely over the cost to comply, but that was ultimately never decided by the State Water Board." To the extent that the WRCB staff's comments at the workshop regarding BTA infeasibility and minimal environmental impacts might be considered implied or express findings, these findings are not supported in law or substantial evidence.

[25] Section 5 of SB 846; Pub. Res. Code section 25548(e).

[26] Legislation should be construed, if reasonably possible, to preserve its constitutionality and thus avoid the constitutional issue inherent in a contrary construction (*Department of Corrections*

than simply impose a mitigation fee on PG&E. Instead, it must order PG&E to install cooling towers by 2024/2025, or demonstrate, supported by substantial evidence, why the environmental benefits of doing so do not outweigh the financial costs of installing them.

As stated by the WRCB Staff in the Final Substitute Environmental Document on its OTC Policy, "[t]his policy is needed to address an ongoing critical impact to the State's waters that remains unaddressed at the national level for existing facilities despite § 316(b)'s enactment more than 35 years ago." With the passage of an additional twelve years since 2010, it is now 47 years since enactment of CWA Section 316. And Diablo Canyon has been operating for many decades with an antiquated OTC system that causes massive adverse impacts to the marine environment. In fact, substantial evidence, which is contained in the record on the OTC Policy, demonstrates that Diablo Canyon's marine life impacts are significantly larger than all the remaining OTC power plants combined.

Commenters urge the WRCB to stay true to its word:

> Thus, in passing the 2021 amendment to the 2010 Statewide Water Quality Control Policy that conformed the compliance dates for the Diablo Canyon reactors to their [2024/2025] retirement dates, the WRCB committed that it remains "firmly committed"to "timely compliance" with the deadlines for modernizing cooling systems at electric plants.[27]

CONCLUSION

The WRCB should withdraw its proposal to revise the November 2, 2024 and August 28, 2025 deadlines as set forth in the 2021 amendment to the 2010 Statewide Water Quality Control Policy. Finally, the WRCB should clarify that it will require Diablo Canyon to operate in compliance with those deadlines or require that the reactors must cease to operate.

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v. Workers' Comp. Appeals Bd. (1979) 23 Cal. 3d 197, 207; *Conservatorship of Hofferber* (1980) 28 Cal. 3d 161, 175; *Rowe v. Superior Court* (1993) 15 Cal. App. 4th 1711, 1722.)

[27] WRCB Resolution 2020-0029 at 4.

Dated: March 17, 2023

Respectfully submitted,

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